Draft Supplemental Recirculated Environmental Impact Report (October 2020) Revisions to Title 19-Kern County Zoning Ordinance– (2020 A), Focused on Oil and Gas Local Permitting

SCH# 2013081079

Volume 1
Chapters 1 through 11

REVISIONS to Title 19 – KERN COUNTY ZONING ORDINANCE – (2020 A), Focused on Oil and Gas Local Permitting

Kern County Planning and Natural Resource Department
2700 M Street, Suite 100
Bakersfield, CA 93301-2370
(661) 862-8600

October 2020

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Lorelei H. Oviatt, AICP, Director
2700 "M" Street, Suite 100
Bakersfield, CA 93301-2323
Phone: (661) 862-8600
Fax: (661) 862-8601 TTY Relay 1-800-735-2929
Email: planning@kerncounty.com
Web Address: http://kernplanning.com/

PLANNING AND NATURAL RESOURCES DEPARTMENT

Planning
Community Development
Administrative Operations

California Environmental Quality Act (CEQA)

Supplemental Recirculated Environmental Impact Report

DATE: October 30, 2020

TO: See Attached Mailing List

FROM: Kern County Planning and
Natural Resources Department
Attn: Cindi Hoover, Lead Planner
2700 "M" Street, Suite 100
Bakersfield, CA 93301
(661) 661-862-8629
hooverc@kerncounty.com

RE: DRAFT SUPPLEMENTAL RECIRCULATED ENVIRONMENTAL IMPACT REPORT (October 2020) (SCH # 2013081079)

This is to advise that the Kern County Planning and Natural Resources Department has prepared a Draft Supplemental Recirculated Environmental Impact Report (SREIR) for the project identified below. As mandated by State law, the public review period for this document is 45 days. The entire Draft SREIR document and documents referenced in the Draft SREIR are available for review online at https://kernplanning.com/SREIR2020-oil-gas-zoning-revisions/ or at the Planning and Natural Resources Department, 2700 "M" Street, Suite 100, Bakersfield, CA 93301 by appointment.

A Draft SREIR (August 2020) was prepared, incorporating agency and public comments received during the NOP/IS and Scoping Process, and circulated August 3, 2020, for a 45 day public review period. This is the second circulation of a DSREIR for this process and incorporates all comments received on the Draft SREIR (August 2020) and the full document circulated August 2020. This SREIR (October 2020) shows all text changes from the earlier SREIR (August 2020) as italics, with text additions underlined and text deletions as strikeouts.

PROJECT TITLE: Draft Supplemental Recirculated Environmental Impact Report (October 2020) for Revisions to Title 19- Kern County Zoning Ordinance 2020 (A), Focused on Oil and Gas Local Permitting (SCH # 2013081079)

PROJECT LOCATION: The project boundary (Local Permitting Boundary Area) encompasses 3,700 square miles and generally includes the San Joaquin Valley Floor portion of Kern County up to an elevation of 2,000 feet. The boundary includes: west side - the San Luis Obispo County line, north side - the Kings and Tulare county lines, east and south sides - the 2,000-foot elevation contours, squared off to the nearest section line.

PROJECT DESCRIPTION: The purpose of this Supplemental Recirculated Environmental Impact Report (October 2020) is to provide compliance with CEQA for the reconsideration by the Planning Commission and Board of Supervisors of the Zoning Ordinance revisions focused on Oil and Gas Local Permitting.

The proposed Project is a reconsideration of revisions to various Chapters of Title 19 Kern County Zoning Ordinance to implement a new permit process for oil and gas activities. The revisions include new site development standards and review processes for all oil and gas exploration, extraction, operations, and production activities in unincorporated Kern County by:

(a) Removing the "Unrestricted Drilling" Section in Chapter 19.98 and updated "Drilling by Ministerial Permit" and "Drilling by Conditional Use Permit" Sections;

(b) Establishing a "Tier Area" maps to address different land uses and zone districts where oil and gas activities occur and are proposed to occur in the future;

(c) Establishing an Oil and Gas Conformity Review and Minor Activity Review, as part of the "Drilling by Ministerial Permit" Section in Chapter 19.98, to ensure compliance with all applicable Development and Implementation Standards and Conditions;

(d) Establishing Development and Implementation Standards and Conditions Section in Chapter 19.98;

(e) Establishing requirements for site plan sign-off by owners of the surface and minerals for split estate ownership;

(f) Revising additional Chapters of the Zoning Ordinance to ensure consistency with the new requirements of this SREIR. These Chapters include: 19.08 – Interpretations and General Standards, 19.48 – Drilling Island (DI) District, 19.50 – Floodplain Primary District, 19.66 – Petroleum Extraction (PE) Combining District, 19.81 - Outdoor Lighting (Dark Skies Ordinance), 19.88 – Hillside Development, 19.102 – Permit Procedures, and 19.108 – Nonconforming Uses, Structures, and Lots.

CEQA Guidelines Section 15088.5 (f) (1) provides that when an Environmental Impact Report (EIR) is recirculated, Kern County, as Lead Agency, may require that reviewers submit new comments on the SREIR, and the lead agency need not to respond to those comments received in the earlier circulation period. Kern County will therefore respond in the Final Supplemental Recirculated EIR to new comments during this comment period and through the Planning Commission and Board of Supervisors hearings.

The Kern County Planning and Natural Resources Department will host a virtual public briefing workshop to provide an overview of the document, take online public comments and review opportunities for public comment on: **November 10, 2020,** at 1:30 pm., via Microsoft Live Events. Instructions for participating in the virtual public workshop will be available on the Kern County Planning and Natural Resources website (www.kernplanning.com) on November 6, 2020.

A public hearing has been scheduled with the Kern County Planning Commission to receive comments and consider the project for recommendation for approval, conditional approval or denial to the Kern County Board of Supervisors on: **February 11, 2021,** at 7:00 p.m. or soon thereafter, Chambers of the Board of Supervisors, First Floor, Kern County Administrative Center, 1115 Truxtun Avenue, Bakersfield, California. A notice, as required by law will be sent in advance of the hearing.

The comment period for this document closes on December 14, 2020. Comments can be submitted to the address above or emailed to Cindi Hoover, Lead Planner (hooverc@kerncounty.com).

Signature: Cindi H

Name: Cindi Hoover, Lead Planner

SREIR Oil & Gas
WO #PP13280
I:\Planning\WORKGRPS\WP\LABELS\
SEIR - Oil & Gas (2nd) labels.doc
Sc 03/19/20 (CLH 10/21/20)

City of Maricopa
P.O. Box 548
Maricopa, CA 93252

City of Arvin
P.O. Box 548
Arvin, CA 93203

Bakersfield City Planning Dept
1715 Chester Avenue
Bakersfield, CA 93301

Bakersfield City Public Works Dept
1501 Truxtun Avenue, 2nd Floor
Bakersfield, CA 93301

California City Planning Dept
21000 Hacienda Blvd.
California City, CA 93515

Delano City Planning Dept
P.O. Box 3010
Delano, CA 93216

City of Shafter
336 Pacific Avenue
Shafter, CA 93263

City of McFarland
401 West Kern Avenue
McFarland, CA 93250

City of Ridgecrest
100 West California Avenue
Ridgecrest, CA 93555

City of Wasco
764 E Street
Wasco, CA 93280

City of Taft
Planning & Building
209 East Kern Street
Taft, CA 93268

City of Tehachapi
Attn: John Schlosser
115 South Robinson Street
Tehachapi, CA 93561-1722

Los Angeles Co Reg Planning Dept
320 West Temple Street
Los Angeles, CA 90012

Inyo County Planning Dept
P.O. Drawer "L"
Independence, CA 93526

Kings County Planning Agency
1400 West Lacey Blvd, Bldg 6
Hanford, CA 93230

Santa Barbara Co Resource Mgt Dept
123 East Anapamu Street
Santa Barbara, CA 93101

San Bernardino Co Planning Dept
385 North Arrowhead Avenue, 1st Floor
San Bernardino, CA 92415-0182

San Luis Obispo Co Planning Dept
Planning and Building
976 Osos Street
San Luis Obispo, CA 93408

U.S. Bureau of Land Management
Caliente/Bakersfield
3801 Pegasus Drive
Bakersfield, CA 93308-6837

Tulare County Planning & Dev Dept
5961 South Mooney Boulevard
Visalia, CA 93291

Ventura County RMA Planning Div
800 South Victoria Avenue, L1740
Ventura, CA 93009-1740

U.S. Forest Service
Los Padres National Forest
6755 Hollister Avenue, Suite 150
Goleta, CA 93117

U.S. Bureau of Land Management
Ridgecrest Field Office
300 South Richmond Road
Ridgecrest, CA 93555

China Lake Naval Weapons Center
Tim Fox, RLA - Comm Plans & Liaison
429 E Bowen, Building 981
Mail Stop 4001
China Lake, CA 93555

Edwards AFB,
Monique Florez, Mission Sustainability Liason
412 TW/XPO, Bldg 2750, Ste 117-14
195 East Popson Avenue
Edwards AFB, CA 93524

Federal Aviation Administration
Western Reg Office/
777 South Aviation Boulevard
Suite 150
El Segundo, CA 90245

Federal Communications Comm
18000 Studebaker Road, #660
Cerritos, CA 90701

U. S. Fish & Wildlife Service
Division of Ecological Services
2800 Cottage Way #W-2605
Sacramento, CA 95825-1846

U.S. Fish & Wildlife Service
Hopper Mountain (Bitter Creek)
2493 Portola Road, Suite A
Ventura, CA 93003

Environmental Protection Agency
Region IX Office
75 Hawthorn Street
San Francisco, CA 94105

U.S. Dept of Agriculture/NRCS
5080 California Avenue, Ste 150
Bakersfield, CA 93309-0711

U.S. Army Corps of Engineers
P.O. Box 997
Lake Isabella, CA 93240

State Air Resources Board
Stationary Resource Division
P.O. Box 2815
Sacramento, CA 95812

So. San Joaquin Valley Arch Info Ctr
California State University of Bkfd
9001 Stockdale Highway
Bakersfield, CA 93311

Caltrans/Dist 6
Planning/Land Bank Bldg.
P.O. Box 12616
Fresno, CA 93778

Caltrans/Dist 9
Planning Department
500 South Main Street
Bishop, CA 93514

Caltrans/
Division of Aeronautics, MS #40
P.O. Box 942873
Sacramento, CA 94273-0001

Caltrans/
Division of Structures
Attn: Jim Roberts
P.O. Box 1499
Sacramento, CA 95807

State Clearinghouse
Office of Planning and Research
1400 10th Street, Room 222
Sacramento, CA 95814

State Dept of Conservation
Director's Office
801 "K" Street, MS 24-01
Sacramento, CA 95814-3528

State Dept of Conservation
Geologic Energy Management Division
4800 Stockdale Highway, Ste 108
Bakersfield, CA 93309

State Dept of Conservation
Geologic Energy Management Division
801 "K" Street, MS 20-20
Sacramento, CA 95814-3530

Office of the State Geologist
Headquarters
801 "K" Street, MS 12-30
Sacramento, CA 95814

State Dept of Conservation
Office of Land Conservation
801 "K" Street, MS 18-01
Sacramento, CA 95814

State Dept of Conservation
Office of Mine Reclamation
801 "K" Street MS 09-06
Sacramento, CA 95814-3529

State Dept of Conservation
Div Recycling Cert. Sec.
801 "K" Street, MS 19-01
Sacramento, CA 95814

State Mining and Geology Board
801 K Street, MS 20-15
Sacramento, CA 95814

California State University
Bakersfield - Library
9001 Stockdale Highway
Bakersfield, CA 93309

California Energy Commission
James W. Reed, Jr.
1516 Ninth Street
Mail Stop 17
Sacramento, CA 95814

California Fish & Wildlife
1234 East Shaw Avenue
Fresno, CA 93710

State Dept of Food & Agriculture
1220 "N" Street
Sacramento, CA 95814

California Highway Patrol
Planning & Analysis Division
P.O. Box 942898
Sacramento, CA 94298-0001

State Office of Historical Pres
Attention Susan Stratton
P.O. Box 942896
Sacramento, CA 95296-0001

Integrated Waste Management
P.O. Box 4025, MS #15
Sacramento, CA 95812-4025

State Dept of Parks & Recreation
Tehachapi District
Angeles District - Mojave Desert Sector
15701 E. Avenue M
Lancaster, CA 93535

State Water Resources Control Board
Division of Drinking Water
Attn: Jesse Dhaliwal, Sr. Sanitary Eng
4925 Commerce Drive, Suite 120
Bakersfield, CA 93309

Public Utilities Comm Energy Div
505 Van Ness Avenue
San Francisco, CA 94102

California Regional Water Quality
Control Board/Central Valley Region
1685 E Street
Fresno, CA 93706-2020

Sequoia National Forest
Kern River Ranger Station
11380 Kernville Road
Kernville, CA 93238

State Lands Commission
100 Howe Avenue, Ste 100-South
Sacramento, CA 95825-8202

State Dept of Toxic Substance Control
Environmental Protection Agency
1515 Tollhouse Road
Clovis, CA 93612

State Department of Toxic
Substances Control
1000 “I” Street
P.O. Box 806
Sacramento, CA 95812

State Dept of Water Resources
San Joaquin Dist.
3374 East Shields Avenue, Room A-7
Fresno, CA 93726

State Dept of Water Resources
Div. Land & Right-of-Way
P.O. Box 942836
Sacramento, CA 94236

CalRecycle
Dept of Resources, Recycling, and Recovery
1001 "I" Street
Sacramento, CA 95812

Kern County
Agriculture Department

Kern County Airports Department

County Clerk

Kern County Administrative Officer

Kern County Public Works Department/
Building & Development/Floodplain

Kern County Public Works Department/
Building & Development/Survey

Kern County
Public Health Services Department/
Environmental Health Division

Kern County Fire Dept
David Witt, Fire Chief

Kern County Fire Dept
Derek Tsinger, Fire Marshal

Kern County Fire Dept
Michael Nicholas

Kern County Library/Beale
Local History Room

Kern County Library/Beale
Andie Sullivan

Kern County Museum
3801 Chester Avenue
Bakersfield, CA 93301

Kern County Parks & Recreation

Kern County Sheriff's Dept
Administration

Kern County Public Works Department/
Building & Development/Development Review

Kern County Public Works
Department/Operations &
Maintenance/Regulatory Monitoring & Reporting

Kern County Public Works Department/
Building & Development/Code Compliance

Kern County Employer’s Training Resource

East Kern Air Pollution
Control District

KernCOG
1401 19th Street - Suite 300
Bakersfield, CA 93301

Kern County Superintendent of Schools
Attention School District Facility Services
1300 17th Street
Bakersfield, CA 93301

Kern High School Dist
5801 Sundale Avenue
Bakersfield, CA 93309

Local Agency Formation Comm/LAFCO
5300 Lennox Avenue, Suite 303
Bakersfield, CA 93309

California Air Resources Board
Kathleen H. Kozawa
Program Assessment Section
Industrial Strategies Division
1001 I Street,
Sacramento CA 95814

California Air Resources Board
Luis A. Leyva
Air Pollution Specialist
1001 I Street,
Sacramento CA 95814

North of the River Parks & Rec Dist
405 Galaxy Avenue
Bakersfield, CA 93308

California Highway Patrol
Shaun C. Crosswhite – Lieutenant, Area Commander Buttonwillow Area 426
29449 Stockdale Highway
Bakersfield, CA 93314

California Highway Patrol
Scot Loetscher – Captain
9855 Compagnoni Street
Bakersfield, CA 93313

California Highway Patrol
Jeffrey L. Briggs – Lieutenant
Bakersfield Area – 420
9855 Compagnoni Street
Bakersfield, CA 93313

Kern County Water Agency
P.O. Box 58
Bakersfield, CA 93302-0058

Delano Mosquito Abatement Dist
Attention John G. Davis
P.O. Box 220
Delano, CA 93215

San Joaquin Valley
Air Pollution Control District
Attn: Morgan Lambert
1990 East Gettysburg Avenue
Fresno, CA 93726

Golden Empire Transit
1830 Golden State Avenue
Bakersfield, CA 93301

West Side Mosquito
Abatement Dist.
P.O. Box 205
Taft, CA 93268

Kern Mosquito Abatement Dist
4705 Allen Road
Bakersfield, CA 93314

South Fork Mosquito Abatement Dist
P.O. Box 750
Kernville, CA 93238-1298

Mojave Airport
1434 Flightline
Mojave, CA 93501

Bakersfield Municipal Airport
4101 Truxtun Avenue
Bakersfield, CA 93309

California City Airport
22636 Airport Way, #8
California City, CA 93505

Rosamond Skypark/Airport
4000 Knox Avenue
Rosamond, CA 93560

Inyokern Airport
P.O. Box 634
Inyokern, CA 93527

Minter Field Airport District
201 Aviation Street
Shafter, CA 93263

Construction Materials Assoc of CA
1029 "J" Street, Suite 420
Sacramento, CA 95814

East Kern Airport Dist
1434 Flightline
Mojave, CA 93501

East Kern Airport Dist Engineer
3900 Ridgemoor Avenue
Bakersfield, CA 93306

Adams, Broadwell, Joseph & Cardozo
Attention: Janet M. Laurain
601 Gateway Boulevard, Suite 1000
South San Francisco, CA 94080

Mountain Valley Airport
P.O. Box 100
Tehachapi, CA 93581

Aero Sports Skypark Corporation
P.O. Box 2567
Rosamond, CA 93560

Los Angeles Audubon
926 Citrus Avenue
Los Angeles, CA 90036-4929

Tehachapi City Hall/Airport
115 South Robinson Street
Tehachapi, CA 93561

Center for Biological Diversity
Attn: Adam Lazar
351 California Street, #600
San Francisco, CA 94104

Desert Tortoise Preserve Committee
4067 Mission Inn Avenue
Riverside, CA 92501

AT&T California
OSP Engineering/Right-of-Way
4901 Ashe Road
Bakersfield, CA 93313

Kern Audubon Society
Attn: Frank Bedard, Chairman
4124 Chardonnay Drive
Bakersfield, CA 93306

Richard Drury
Komalpreet Toor
Stacey Oborne
Lozeau Drury LLP
1939 Harrison Street, Suite 150
Oakland, CA 94612

Friant Water Users Authority
854 North Harvard Avenue
Lindsay, CA 93247-1715

Beth Boyst
Pacific Crest Trail Program Manager
1323 Club Drive
Vallejo, CA 94592

Pacific Gas & Electric Co
Land Projects
650 "O" Street, First Floor
Fresno, CA 93760-0001

Smart Growth - Tehachapi Valleys
P.O. Box 1894
Tehachapi, CA 93581-1894

Southern California Edison
Planning Dept.
421 West "J" Street
Tehachapi, CA 93561

Southern California Gas Co
35118 McMurtrey Avenue
Bakersfield, CA 93308-9477

Chumash Council of Bakersfield
Julio Quair
729 Texas Street
Bakersfield, CA 93307

Kern Valley Indian Council
Historic Preservation Office
P.O. Box 401
Weldon, CA 93283

Mojave Chamber of Commerce
P.O. Box 935
Mojave, CA 93502

Anitra Kass
Pacific Crest Trail Association
41860 Saint Annes Bay Drive
Bermuda Dunes, CA 92203

Sheppard Mullin
Attn: Kendra Joy Casper
333 South Hope Street
Los Angeles, CA 90071

Southern California Edison
120 Woodlands Drive
Wofford Heights, CA 93285

Southern California Edison
Planning Dept.
510 S. China Lake Blvd.
Ridgecrest, CA 93555

Southern California Gas Co
Transportation Dept
9400 Oakdale Avenue
Chatsworth, CA 91313-6511

Matthew Gorman
The Gorman Law Firm
1346 E. Walnut Street, Suite 220
Pasadena, CA 91106

Santa Rosa Rancheria
Ruben Barrios, Chairperson
P.O. Box 8
Lemoore, CA 93245

Tubatulabals of Kern County
Attn: Robert Gomez, Chairperson
P.O. Box 226
Lake Isabella, CA 93240

David Laughing Horse Robinson
P.O. Box 20849
Bakersfield, CA 93390

Center on Race, Poverty
& the Environment
Attn: Marissa Alexander
5901 Christie Avenue, Suite 208
Emeryville, CA 94608

California Farm Bureau
2300 River Plaza Drive, NRED
Sacramento, CA 95833

Native American Heritage Preservation Council of Kern County
Attn: Gene Albitre
3401 Aslin Street
Bakersfield, CA 93312

Pacific Gas & Electric Co
Land Mgt
Attn: Matt Coleman
1918 "H" Street
Bakersfield, CA 93301

Sierra Club/Kern Kaweah Chapter
P.O. Box 3357
Bakersfield, CA 93385

Southern California Edison
P.O. Box 410
Long Beach, CA 90801

Southern California Edison
Planning Dept.
25625 West Rye Canyon
Valencia, CA 91355

Verizon California, Inc.
Attention Engineering Department
520 South China Lake Boulevard
Ridgecrest, CA 93555

Kern Valley Indian Council
Attn: Robert Robinson, Chairperson
P.O. Box 401
Weldon, CA 93283

Tejon Indian Tribe
Octavio Escobedo, Chairperson
1731 Hasti-Acres Drive, Suite 108
Bakersfield, CA 93309

Kitanemuk & Yowlumne Tejon Indians
Chairperson
115 Radio Street
Bakersfield, CA 93305

San Fernando Band of Mission Indians
Attn: John Valenzuela, Chairperson
P.O. Box 221838
Newhall, CA 91322

Tule River Indian Tribe
Neal Peyron, Chairperson
P.O. Box 589
Porterville, CA 93258

Bear Valley Community Services Dist
28999 South Lower Valley Road
Tehachapi, CA 93561-6529

Carol Bender
13340 Smoke Creek Avenue
Bakersfield, CA 93314-9025

Bellanave Corporation
George Borba
11461 Taft Highway
Bakersfield, CA 93311

Bear Valley Springs Assoc
Environmental Control Committee
29541 Rolling Oak Drive
Tehachapi, CA 93561

Country Oak Homeowners Assoc
PO Box 1424
Tehachapi, CA 93581

Bolthouse Properties
Attn: Brad DeBranch
2000 Oak Street, Suite 250
Bakersfield, CA 93301

Capitol Oil Corporation
3840 Watt Avenue, Bldg B
Sacramento, CA 95821-2640

Center on Race, Poverty
& the Environmental/
CA Rural Legal Assistance Foundation
1012 Jefferson Street
Delano, CA 93215

Rosamond Skypark
Attn: George Fischer
4000 Knox Avenue
Rosamond, CA 93560

Clifford, Jenkins & Brown
1430 Truxtun Avenue, Suite 900
Bakersfield, CA 93301

Hurlbutt, Clevenger,
Long, Vortmann & Rauber
615 South Atwood Street
Visalia, CA 93277

Crimson Resource Management
Attention Kristine Boyer
5001 California Avenue, Suite 206
Bakersfield, CA 93309

Cummings Valley Protective Association
P.O. Box 1020
Tehachapi, CA 93581

State Dept of Parks/Hungry Valley
PO Box 1360
Lebec, CA 93243

Metro Water Dist of So CA
Ms. Rebecca De Leon
Environmental Planning Team
700 N. Alameda Street, US3-230
Los Angeles, CA 90012

Kern River Parkway Committee
PO Box 1861
Bakersfield, CA 93303

Kern River Valley Chamber of Commerce
Katherine Evans
P.O. Box 567
Lake Isabella, CA 93240

Tehachapi Resource Cons Dist
321 West "C" Street
Tehachapi, CA 93561-2011

LIUNA
Attn: Danny Zaragoza
2201 “H” Street
Bakersfield, CA 93301

Nature Conservancy West Reg Office
201 Mission Street, 4th Floor
San Francisco, CA 94105

Tricor Energy, LLC
190 Newport Center Drive, Suite 100
Newport Beach, CA 92660

A E Corporation
Planning Department
901 Via Piemonte, 5th Floor
Ontario, CA 91764

WZI, Inc.
1717 - 28th Street
Bakersfield, CA 93301

Tulare Basin Wetlands Association
Attention Dennis Slater
5316 Muirfield Drive
Bakersfield, CA 93306-9704

Bakersfield City Parks & Rec Dept
4101 Truxtun Avenue
Bakersfield, CA 93301

Buttonwillow Rec & Parks Dist
P.O. Box 434
Buttonwillow, CA 93206-9320

Vintage Petroleum, LLC
Attn: Teri Altenburger
10800 Stockdale Highway
Bakersfield, CA 93311

Bear Mountain Rec & Parks Dist
P.O. Box 658
Lamont, CA 93241

Shafter Rec & Parks Dist
700 East Tulare Avenue
Shafter, CA 93263

Tehachapi Parks & Recreation Dist
P.O. Box 373
Tehachapi, CA 93561

West Side Rec & Parks Dist
P.O. Box 1406
Taft, CA 93268

State Dept of Public Utilities Commission
505 Van Ness Avenue, Rm 2003
San Francisco, CA 94102-3214

North West Kern Resource Cons Dist
5080 California Avenue, Suite 150
Bakersfield, CA 93309

So. San Joaquin Muni Utility Dist
P.O. Box 279
Delano, CA 93216

Desert Lake Community Service District
P.O. Box 567
Boron, CA 93516

Arvin Community Services Dist
309 Campus Drive
Arvin, CA 93203

California City Public Works Dept
8190 California City Blvd.
California City, CA 93505

Frazier Park Public Utility Dist
P.O. Box 1512
Frazier Park, CA 93225

Rosamond Community Serv Dist
3179 - 35th Street West
Rosamond, CA 93560

Enos Lane Public Utility Dist
P.O. Box 22198
Bakersfield, CA 93390

Lake Isabella Community Serv Dist
P.O. Box 647
Lake Isabella, CA 93240

Boron Community Service Dist
P.O. Drawer B
Boron, CA 93516

Inyokern Community Serv Dist
P.O. Box 1418
Inyokern, CA 93527

Mojave Public Utility Dist
15844 "K" Street
Mojave, CA 93501

East Niles Community Serv Dist
P.O. Box 6038
Bakersfield, CA 93306

Lost Hills Utility Dist
P.O. Box 249
Lost Hills, CA 93249

Stallion Springs Community Services Dist
28500 Stallion Springs Drive
Tehachapi, CA 93561

Golden Hills Community Serv Dist
P.O. Box 637
Tehachapi, CA 93581

Wasco Public Works Dept
801 - 18th Street
Wasco, CA 93280

Quail Valley Water Dist
3200 21st Street, Ste 401
Bakersfield, CA 93301

Lamont Public Utility Dist
8624 Segrue Road
Lamont, CA 93241

Shafter-Wasco Irrigation Dist
P.O. Box 1168
Wasco, CA 93280-8068

Superior Mutual Water Co
19474 Enos Lane
Bakersfield, CA 93312-9501

Indian Wells Valley Groundwater
Authority
500 West Ridgecrest Boulevard
Ridgecrest, CA 93555

Stockdale Mutual Water Co
P.O. Box 788
Bakersfield, CA 93302

Alta Sierra Mutual Water Co
10502 Sequoia Drive, No. 11
Wofford Heights, CA 93285

Semi Tropic Water Storage Dist
P.O. Box Z
Wasco, CA 93280

Rosedale-Rio Bravo Water Dist
P.O. Box 20820
Bakersfield, CA 93390-0820

Ashe Water Dist
Dept of Water Resources
4101 Truxtun Avenue
Bakersfield, CA 93309

Aerial Acres Water System
18110 Avenue B
North Edwards, CA 93523

Arvin-Edison Water Storage Dist
P.O. Box 175
Arvin, CA 93203

Belridge Water Storage Dist
21908 Seventh Standard Road
McKittrick, CA 93251

Tehachapi-Cummings Co Water Dist
P.O. Box 326
Tehachapi, CA 93561

Bella Vista Water Co
Attention Gerald Hyneman
P.O. Box 15309
Weldon, CA 93283

Brock Mutual Water Co
12001 Brockridge Court
Bakersfield, CA 93309

Antelope Valley-East Kern
Water Agency
6500 West Avenue N
Palmdale, CA 93551

Bodfish Water Co
P.O. Box 842
Lake Isabella, CA 93240

Tejon-Castaic Water Dist
P.O. Box 1000
Lebec, CA 93243

Bakersfield City Water Resource Dept
1000 Buena Vista Road
Bakersfield, CA 93311

Buttonwillow County Water Dist
P.O. Box 874
Buttonwillow, CA 93206

California Water Service Co
3725 South "H" Street
Bakersfield, CA 93304

Berrenda Mesa Water Dist
14823 Highway 33
Lost Hills, CA 93249-9734

Cawelo Water Dist
17207 Industrial Farm Road
Bakersfield, CA 93308-9801

Edgemont Acres Water Co
P.O. Box 966
North Edwards, CA 93523

Buena Vista Water Storage Dist
P.O. Box 756
Buttonwillow, CA 93206

Edmonston Acres Muni Water Co
25465 Barbara Street
Arvin, CA 93203

Friant Water Users Authority
854 North Harvard Avenue
Lindsay, CA 93247-1715

Casa Loma Water Co
1016 Lomita Drive
Bakersfield, CA 93307

Erskine Creek Water Co
P.O. Box 656
Lake Isabella, CA 93240

West Kern Water Dist
P.O. Box 1105
Taft, CA 93268-1105

Kern River Groundwater Sustainability
Agency
City Hall North
1600 Truxtun Avenue
Bakersfield, CA 93301

Vaughn Water Co.
10014 Glenn Street
Bakersfield, CA 93312

Greenfield County Water Dist
551 Taft Highway
Bakersfield, CA 93307

Edmonston Acres Muni Water Co
25465 Barbara Street
Arvin, CA 93203

Gosford Road Water Assoc
13958 Gosford Road
Bakersfield, CA 93313

Kern Delta Water Dist
501 Taft Highway
Bakersfield, CA 93307

Goose Lake Water Co
16232 Palm Avenue
Bakersfield, CA 93314

California Regional Water Quality
Control Board/Lahontan Region
15095 Amargosa Road - Bld 2, Suite 210
Victorville, CA 92392

Kern Water Bank Authority
1620 Mill Rock Way, Suite 500
Bakersfield, CA 93311

Wheeler Ridge-Maricopa Water Dist
12109 Highway 166
Bakersfield, CA 93313-9630

Kern-Tulare Water Dist
5001 California Avenue, Suite 102
Bakersfield, CA 93309-1692

La Hacienda Water Co, Inc.
P.O. Box 60679
Bakersfield, CA 93386-0679

Indian Wells Valley Water Dist
P.O. Box 1329
Ridgecrest, CA 93556

Lamont Storm Water Dist
P.O. Box 543
Lamont, CA 93241

Los Angeles Dept of Water & Power
111 North Hope Street, Rm 1121
Los Angeles, CA 90012

Kern River Valley Water Co
P.O. Box 1260
Lake Isabella, CA 93240

Davenport Mutual Water Assn
P.O. Box 1503
Rosamond, CA 93560

Mountain Mesa Water Co
12707 Highway 178
Lake Isabella, CA 93240

Lake of the Woods
Mutual Water Co.
7025 Cuddy Valley Road
Frazier Park, CA 93225

Mettler County Water Dist
1822 Steven Drive
Bakersfield, CA 93313

North of the River Muni Water Dist
P.O. Box 5638
Bakersfield, CA 93388-5638

Lebec County Water Dist
P.O. Box 910
Lebec, CA 93243

North Kern Water Storage Dist
P.O. Box 81435
Bakersfield, CA 93380-1435

Pinion Pines Mutual Water Co
1467 Tecuya Street
Frazier Park, CA 93225

Lost Hills Water Dist
1405 Commercial Way, Suite 125
Bakersfield, CA 93309

Olcese Water Dist
P.O. Box 60679
Bakersfield, CA 93386-0679

Riverkern Mutual Water Co
P.O. Box 856
Kernville, CA 93238

North Edwards Water Dist
13001 Claymine Road
North Edwards, CA 93523

Rand Communities Co Water Dist
P.O. Box 198
Randsburg, CA 93554

Eastern Kern Resource Cons Dist
300 South Richmond Road
Ridgecrest, CA 93555-4436

Oildale Mutual Water Co
P.O. Box 5638
Bakersfield, CA 93388

Arvin Community Services Dist
309 Campus Drive
Arvin, CA 93203

Midway School Dist
P.O. Box 39
Fellows, CA 93224

Metro Water Dist of So CA
Ms. Rebecca De Leon
Environmental Planning Team
700 N. Alameda Street, US3-230
Los Angeles, CA 90012

Kern Valley Resource Cons Dist
P.O. Box 58
Weldon, CA 93283

Muroc Unified School Dist
17100 Foothill Avenue
North Edwards, CA 93523

Antelope Valley Resource Cons Dist
10148 West Avenue I
Lancaster, CA 93536

Lost Hills Union School Dist
P.O. Box 158
Lost Hills, CA 93249

Richland-Lerdo Union School Dist
331 Shafter Avenue
Shafter, CA 93263

Lerdo School Dist
331 Shafter Avenue
Shafter, CA 93263

Mountain View School Dist
8201 Palm Avenue
Lamont, CA 93241

Semi Tropic School Dist
25300 Highway 46
Wasco, CA 93280-9540

Mojave Unified School Dist
3500 Douglas
Mojave, CA 93501

Pond Union School District
29585 Pond Road
Wasco, CA 93280-9772

South Fork Union School Dist
5225 Kelso Valley Road
Weldon, CA 93283

Norris School Dist
6940 Calloway Drive
Bakersfield, CA 93312

Rosedale Union School Dist
2553 Old Farm Road
Bakersfield, CA 93312

Taft City School Dist
820 North 6th Street
Taft, CA 93268

Rio Bravo-Greeley Union School Dist
6521 Enos Lane
Bakersfield, CA 93314

Sierra Sands Unified School Dist
113 Felspar
Ridgecrest, CA 93555

Vineland School Dist.
8701 Weedpatch Highway
Bakersfield, CA 93307

Shafter High School Dist
526 Mannel Avenue
Shafter, CA 93263

Standard School Dist
1200 North Chester Avenue
Oildale, CA 93308

Maricopa Unified School Dist
955 Stanislaus Street
Maricopa, CA 93252

Southern Kern Unified School Dist
P.O. Box CC
Rosamond, CA 93560

Tehachapi Unified School Dist
300 S Robinson Street
Tehachapi, CA 93561

Beardsley School Dist
1001 Roberts Lane
Bakersfield, CA 93308

Taft Union High School Dist
701 7th Street
Taft, CA 93268

Wasco Union Elementary School Dist
639 Broadway
Wasco, CA 93280

Buttonwillow Union School Dist
42600 Highway 58
Buttonwillow, CA 93206

Wasco Union High School Dist
P.O. Box 250
Wasco, CA 93280

Bakersfield City School Dist
Education Center
1300 Baker Street
Bakersfield, CA 93305

Delano Joint Union High School Dist
1720 Norwalk Street
Delano, CA 93215-1456

Arvin High School
900 Varsity Street
Arvin, CA 93203

Panama-Buena Vista School Dist
4200 Ashe Road
Bakersfield, CA 93313

Edison School Dist
P.O. Box 368
Edison, CA 93220-0368

Blake School Dist
P.O. Box 53
Woody, CA 93287

West Kern Community College Dist
Attn: Office of the President
29 Emmons Park Drive
Taft, CA 93268

Fairfax Union School Dist
1501 South Fairfax Road
Bakersfield, CA 93307

Caliente Union School Dist
12400 Caliente Creek Road
Caliente, CA 93518

DiGiorgio School Dist
Route 1, Box 34
Arvin, CA 93203

Greenfield Union School Dist
Attn: Darrell Hawley, Director of Facilities
1624 Fairview Road
Bakersfield, CA 93307

Delano Union School Dist.
1405 12th Avenue
Delano, CA 93215

Elk Hills School Dist
P.O. Box 129
Tupman, CA 93276

Kern Valley High School
3340 Erskine Creek Road
Lake Isabella, CA 93240

El Tejon Unified School Dist
P.O. Box 876
Lebec, CA 93243

General Shafter School Dist
1825 Shafter Road
Bakersfield, CA 93313

Lamont School Dist
8201 Palm Avenue
Lamont, CA 93241

Fruitvale School Dist.
7311 Rosedale Highway
Bakersfield, CA 93308-5738

McFarland Unified School Dist
601 Second Street
McFarland, CA 93250

U.S. Marine Corps
Attn: Patrick Christman
Western Regional Environmental Officer
Building 1164/Box 555246
Camp Pendleton, CA 92055-5246

Kern Community College Dist
2100 Chester Avenue
Bakersfield, CA 93301

Lakeside Union School Dist
14535 Old River Road
Bakersfield, CA 93311

Terra-Gen
Randy Hoyle, Sr. Vice Pres
11512 El Camino Real, Suite 370
San Diego, CA 92130

Kernville Union School Dist
3240 Erskine Creek Road
Lake Isabella, CA 93240

U.S. Army
Attn: Tim Kilgannon, Region 9
Coordinator
Office of Strategic Integration
721 - 19th Street, Room 427
Denver, CO 80202

Congentrix Sunshine, LLC
Rick Neff
9405 Arrowpoint Blvd
Charlotte, NC 28273

Maple School Dist
29161 Fresno Avenue
Shafter, CA 93263

U.S. Navy
Attn: Steve Chung
Regional Community & Liaison Officer
1220 Pacific Highway
San Diego, CA 92132-5190

Wind Stream, LLC
Albert Davies
1275 - 4th Street, No. 107
Santa Rosa, CA 95404

U.S. Army
Attn: Philip Crosbie, Chief
Strategic Plans, S3, NTC
P.O. Box 10172
Fort Irwin, CA 92310

U.S. Air Force
Attn: David Bell/AFCEC CZPW
Western Regional/Leg Branch
510 Hickam Avenue, Bld 250-A
Travis AFD, CA 94535-2729^

PG&E
Steven Ng, Manager
Renewal Dev, T&D Intercon
77 Beal Street, Room 5361
San Francisco, CA 94105

Buena Vista Resource Cons Dist
P.O. Box 756
Buttonwillow, CA 93206

EDP Renewables Company
North America, LLC
53 SW Yamhill Street
Portland, OR 97204

Kelly Group
Kate Kelly
P.O. Box 868
Winters, CA 95694

Renewal Resources Group
Holding Company
Rupal Patel
113 South La Brea Avenue, 3rd Floor
Los Angeles, CA 90036

Bill Barnes, Dir of Asset Mgt
AES Midwest Wind Gen
P.O. Box 2190
Palm Springs, CA 92263-2190

Michael Strickler, Sr Project Mgr
Iberdrola Renewables
1125 NW Couch St, Ste 700, 7th Fl
Portland, OR 97209

Beyond Coal Campaign/Sierra Club
Sarah K. Friedman
1417 Calumet Avenue
Los Angeles, CA 90026

Earth Justice, Research & Policy
Attn: Adenike Adeyeye
50 California Street, Suite 500
San Francisco, CA 94111

Sierra Club Environmental Law Program
Attn: Nathan Matthews
85 - 2nd Street, 2nd Floor
San Francisco, CA 94105

Law Office of Todd Cardiff
19010 First Avenue, Suite 219
San Diego, CA 92101

Sierra Club of Los Angeles
Attn: Dr. Tom Williams
4117 Barrett Road
Los Angeles, CA 90032

SCS Engineers
Attn: Jessica O'Brien
4900 California Avenue
Bakersfield, CA 93307

Moxley Int
Attn: Larry Moxley
6208 Timber Creek
Bakersfield, CA 93308

Leadership Counsel for Justice & Accountability
1527 - 19th Street, Suite 212
Bakersfield, CA 93301

Recurrent Energy
Seth Israel
300 California Street, 8th Floor
San Francisco, CA 92109

Vaquero
Wyatt Shipley, Operations Manager
15545 Hermosa Road
Bakersfield, CA 93309

Wm Bolthouse
Attn: Troy Carrigton
7200 E. Brundage Lane
Bakersfield, CA 93307

Colliers International
Attn: Stephen Haupt
10000 Stockdale Highway, Suite 102
Bakersfield, CA 93311

Santa Barbara County Planning
Attn: Gary Kaiser
123 E Anapamu Street, 3rd Fl
Santa Barbara, CA 93101

California Resources Corporation, LLC
Attn: Holly Arnold
10800 Stockdale Highway
Bakersfield, CA 93311

City of Taft
Attn: Dave Noerr
P.O. Box 206
Taft, CA 93268

OXY
Attn: Sisoe Geoger
10800 Stockdale Highway
Bakersfield, CA 93311

Kern County Taxpayers Association
Attn: Michael Turnipseed
331 Truxtun Avenue
Bakersfield, CA 93301

Jardin Comunitario
Attn: Elosia and Arturo Fernandez
670 Ohanneson Avenue
Shafter, CA 93263

Fotowatio Renewable Ventures
Sean Kiernan
44 Montgomery Street, Suite 2200
San Francisco, CA 94104

Darren Kelly, Sr. Business Mgr
Terra-Gen Power, LLC
1095 Avenue of the Americas, 25th Floor, Ste A
New York, NY 10036-6797

Wayne Mayes, Dir Tech Serv
Iberdrola Renewables
1125 NW Couch St, Ste 700, 7th Fl
Portland, OR 97209

Tehachapi Area Assoc of Realtors
Carol Lawhon, Assoc Exe, IOM
803 Tucker Road
Tehachapi, CA 93561

Structure Cast
Larry Turpin, Sales Mgr
8261 McCutchen Road
Bakersfield, CA 93311

Ventura Co. Air Pollution Control Dist
Attn: Tyler Harris
669 County Square Drive, 2nd Fl
Ventura, CA 93003

San Joaquin Valley Op & Maint
Attn: Mark Dedon
3401 Crow Canyon Road
San Ramon, CA 94583

Cal Environmental Protection Agency/
Dept of Toxic Substances Control, Reg 1
Attn: Dave Kereazis, Permit Div - CEQA
8800 Cal Center Drive, 2nd Floor
Sacramento, CA 95826

Kern Audubon Society
Attn: Frank Bedard, Chairman
4124 Chardonnay Drive
Bakersfield, CA 93306

U.S. Bureau of Land Management
Attn: Jeff Prude
3801 Pegasus Drive
Bakersfield, CA 93309

AECOM
Attn: Sarah Esterton
999 Town and Country Road
Orange, CA 92868

Jardin Comunitario
Attn: Amalia Belecher
700 S Shafter Avenue, SP 73
Shafter, CA 93263

ERM
Attn: Denise Toombs
1277 Treat Boulevard, Suite 500
Walnut Creek, CA 94597

Dee Jaspar and Associates, Inc.
Attn: Dee Jaspar
2730 Unicorn Road, Suite A
Bakersfield, CA 93308

CIPA
Attn: Willie Rivera
1200 Discovery Drive, Suite 100
Bakersfield, CA 93309

Aera
Attn: Cindy Pollard
10000 Ming Avenue
Bakersfield, CA 93311

LINN Energy, LLC
Attn: Trent Rosenlieb
5201 Truxtun Avenue, Suite 100
Bakersfield, CA 93309

Canary, LLC
7778 South Union Avenue
Bakersfield, CA 93307

Chevron, USA
Attn: Robin Fleming
9525 Camino Media
Bakersfield, CA 93311

EDF Renewable Energy
Attn: Rick Miller
505 - 14th Street, Suite 1150
Oakland, CA 94612

Jardin Comunitario
Attn: Rodrigo Romo
P.O. Box 795
Shafter, CA 93263

Aera
Attn: Andy Anderson
10000 Ming Avenue
Bakersfield, CA 93311

U.S. Bureau of Land Management
Attn: Sara Acridge
2800 Cottage Way, RM W-1623
Sacramento, CA 95825

W.M. Beaty & Assoc
Attn: Boby Rynearson
P.O. Box 990898
Redding, CA 96099-0898

Aera
Attn: Kathy Miller
10000 Ming Avenue
Bakersfield, CA 93311

California Resources Corporation, LLC
Attn: Bill Gillespie
10800 Stockdale Highway
Bakersfield, CA 93311

Chevron, USA
Attn: John Gruber
9525 Camino Media
Bakersfield, CA 93311

Chevron, USA
Attn: Carla Musser
9525 Camino Media
Bakersfield, CA 93311

Exxon/Mobil Production Company
Attn: Troy Tranquada
12000 Calle Real
Goleta, CA 93117

Hathaway, LLC
Attn: Chad Hathaway
P.O. Box 81385
Bakersfield, CA 93380

Wegis and Young
Attn: Mike Young
12816 Johmani Drive
Bakersfield, CA 93312

Day Centery Murphy
Attn: Tracy Hunckler
3620 American River Drive, Ste 205
Sacramento, CA 95864

Jardin Comunitario
Attn: Samuel Romo
654 Vasquez Avenue
Shafter, CA 93263

Ramsgate Engineering
Attn: Kerrie Roberts
2331 Cepheus Court
Bakersfield, CA 93308

Holder Law Group
Attn: Jason Holder
339 - 15th Street, Suite 202
Oakland, CA 94612

Paul Hastings
Attn: Michael Balster
55 Second Street, 24th Floor
San Francisco, CA 94105

IOPA
Attn: Les Clark
4520 California Avenue, Suite 230
Bakersfield, CA 93309

WSPA
Attn: Suzanne Noble
1518 Mill Rock Way, Suite 103
Bakersfield, CA 93311

California Resources Corporation, LLC
Attn: Joe Ashley
10800 Stockdale Highway
Bakersfield, CA 93311

E&B Natural Resources Management
Attn: Jim Tague
1600 Norris Road
Bakersfield, CA 93309

Halliburton
Attn: Steve Pruett
34722 Seventh Standard Road
Bakersfield, CA 93314

Macpherson Oil Company
Attn: John Miller
P.O. Box 5368
Bakersfield, CA 93388

GE Energy
13000 Jameson Road
Tehachapi, CA 93561

Macpherson Oil Company
Attn: Phil Sorbet
P.O. Box 5368
Bakersfield, CA 93388

Venoco, Inc.
Attn: Ian Livett
6267 Carpentaria Avenue, Suite 100
Carpentaria, CA 93013

Hess Corporation
1675 Chester Avenue
Bakersfield, CA 93301

Seneca Resources Corporation
Attn: Brad Elliott
2131 Mars Court
Bakersfield, CA 93308

Mt Poso CoGen Company, LLC
Attn: Paul Sorbet
100 Wilshire Boulevard, Suite 800
Santa Maria, CA 90401

Macpherson Oil Company
Attn: Tim Lovley
P.O. Box 5368
Bakersfield, CA 93388

Naftex Operating Company
Attn: Randy Horne
P.O. Box 308
Edison, CA 93220

Tricor Refining, LLC
1134 Manor Street
Bakersfield, CA 93308

Vintage Production California
9600 Ming Avenue, Suite 300
Bakersfield, CA 93311

San Joaquin Refining
Attn: Cyrus Mojibi
3129 Standard Street
Bakersfield, CA 93308

Kern County Cattleman's Assoc.
Attn: Austin Snedden
9501 West Lokern Road
McKittrick, CA 93251

Kern Oil and Refining
Attn: Jacob Belin, Jr.
7724 East Panama Lane
Bakersfield, CA 93307

Kern County Farm Bureau
801 Mount Vernon Avenue
Bakersfield, CA 93312

Sequoia Riverland Trust
Attn: Cam Tredennick
427 South Garden Street
Visalia, CA 93277

Western States Petroleum Association
1518 Mill Rock Way, Suite 103
Bakersfield, CA 93311

Kern Citizens for Energy
Attn: Jimmy Yee
5001 California Avenue, Suite 211
Bakersfield, CA 93309

Greater Bakersfield Chamber of Commerce
Attn: Nick Ortiz
1725 Eye Street
Bakersfield, CA 93301

Kern Citizens for Energy
Attn: Tracy Leach
P.O. Box 558
Bakersfield, CA 93302

Kern County Black Chamber of Commerce
P.O. Box 81171
Bakersfield, CA 93380

Greater Lamont Chamber of Commerce
P.O. Box 593
Lamont, CA 93241

Kern County Hispanic Chamber of Commerce
Attn: Jay Tamsi
1601 "H" Street, Suite 201A
Bakersfield, CA 93301

Shafter Chamber of Commerce
336 Pacific Avenue
Shafter, CA 93263

Wasco Chamber of Commerce
1280 Poplar Avenue
Wasco, CA 93280

Arvin Chamber of Commerce
P.O. Box 645
Arvin, CA 93203

Kern Citizens for Sustainable Govn't
1801 Oak Street
Bakersfield, CA 93301

Kern Economic Development Corporation
Attn: Richard Chapman
2700 "M" Street, Suite 200
Bakersfield, CA 93301

Delano Chamber of Commerce
931 High Street
Delano, CA 93215

Grazing Advisory
c/o Farm & Home Office
1031 South Mount Vernon
Bakersfield, CA 93307

Kern County Board of Trade
1115 Truxtun Avenue, 5th Floor
Bakersfield, CA 93301

Taft Chamber of Commerce
400 Kern Street
Taft, CA 93268

Regional Water Quality Control Board
Central Valley Region
Attn: Mary Nichols
11020 Sun Center Drive, Suite 200
Rancho Cordova, CA 95670

Kern Ground Water Authority
P.O. Box 20820
Bakersfield, CA 93390-0850

State Water Resources Control Board
P.O. Box 100
Sacramento, CA 95812-0100

Wonderful Farms
6801 East Lerdo Highway
Shafter, CA 93263

Wm. Bolthouse Farms
7200 East Brundage Lane
Bakersfield, CA 93307

Grimmway Farms
P.O. Box 81498
Bakersfield, CA 93380

Braum Electric
Attn: John Braum
300 East Belle Terrace
Bakersfield, CA 93307

Sun Pacific
Attn: Bob DiPiazza
1095 East Green Street
Pasadena, CA 91106

Tejon Ranch
P.O. Box 1000
Lebec, CA 93243

Ensign
Attn: Larry Lorenz
7001 Charity Avenue
Bakersfield, CA 93308

Earthjustice
Attn: Liz Judge
50 California Street, Suite 500
San Francisco, CA 94111

Sunview Cold Storage
Attn: Marko Zaninovich
31381 Pond Road, Suite 4
McFarland, CA 93250

PCL Industrial Services
Attn: Joe Carrieri
1500 Union Avenue
Bakersfield, CA 93307

Braum Electric
Attn: Kevin Blakenship
301 East Belle Terrace
Bakersfield, CA 93307

Baker Hughes
Attn: Rick Pierucci
3901 Fanucchi Way
Shafter, CA 93263

Sturgeon Services Int'l
Attn: John Powell
3511 Gilmore Avenue
Bakersfield, CA 93308

Key Energy Services, Inc.
Attn: Graham Blaiber
5080 California Avenue
Bakersfield, CA 93309

William L. Trivitt
4509 Devlin Court
Bakersfield, CA 93311

Weatherford Completions
Attn: Gregg Hurst
5060 California Avenue, Suite 1150
Bakersfield, CA 93309

PLCL Plus Int'l, Inc.
Attn: Bill Scroggins
12418-B Rosedale Highway
Bakersfield, CA 93312

Nabors Completion & Production
Attn: Alan Pouds
3651 Pegasus Drive, Suite 101
Bakersfield, CA 93308

Harlan Chappelle
Alta Mesa Holdings, LP
15021 Katy Freeway, Suite 400
Houston, TX 77094

Sturgeon Services Int'l
Attn: Paul Sturgeon
3511 Gilmore Avenue
Bakersfield, CA 93308

Schlumberger Oilfield Services
Attn: Rob Watson
2157 Mohawk Street
Bakersfield, CA 93308

Robert McJilton
Axis Petroleum Company
2420 East 28th Street, Suite 5
Signal Hill, CA 90755

Alan Adler
ABA Energy Corporation
7612 Meany Avenue
Bakersfield, CA 93308

Total Western
Attn: Jeff Jordan
2811 Fruitvale Avenue
Bakersfield, CA 93308

Carl Dean
Bellaire Oil Company
5299 DTC Boulevard, Suite 1300
Greenwood Village, CO 80111

Amiel David
Amrich Energy, Inc.
5315 FM 1960 Road West #B132
Houston, TX 77069

Charles Albright
Albright, Mr. Charles C. 'Jock,' III
729 W. 16th Street, #B8
Costa Mesa, CA 92627

Robert Ferguson
Bob Ferguson - Independent
30448 Rancho Viejo Road, Suite 172
San Juan Capistrano, CA 92675

Bruce Berwager
B&H Energy Partners, LLC
335 N. Sierra Vista Road
Santa Barbara, CA 93108

Casey Armstrong
Armstrong Petroleum Corporation
P.O. Box 1547
Newport Beach, CA 92659

Rey Javier
Brea Canon Oil Company
23903 South Normandie
Harbor City, CA 90710

Clifton Simonson
BFLP (Bentley Family L.P.)
1746-F S. Victoria Avenue, #382
Ventura, CA 93003

Kevin Kane
Bayswater Exploration & Product, LLC
730 17th Street, Suite 610
Denver, CO 80202

Theresa Mitchell
Bud's Oil Company, Inc.
P.O. Box 413
Edison, CA   93220

Tom Gladney
Bodog Resources, LLC
1835 Riada Drive
New Braunfels, TX 78132

Wolf Regener
BNK Petroleum, Inc.
760 Paseo Camarillo, Suite 350
Camarillo, CA 93010

Robert Hodges
Cal E.D.I., Inc.
2200 Pacific Coast Highway, #302
Hermosa Beach, CA 90254

Rick Niemann
Bridgemark Corporation
17671 Irvine Boulevard, Suite 217
Tustin, CA 92780

George Brayton
Brayton-Hodges Petroleum
P.O. Box 3751
Seal Beach, CA 90740

Andrew Prestridge
Cascade Resources, LLC
290 Maple Court, Suite 290
Ventura, CA 93003

James Morrison
C&M Oil Company & Investments, LLC
P.O. Box 2427
Bakersfield, CA 93303

Bruce Holmes
Brittany Oil Co.
23556 Highway 166
Maricopa, CA 93252

Anthony Rausin
Cimarron Oil, LLC
9251 Brunello Court
Bakersfield, CA 93314

Ted Lamare
California Petroleum Holdings, Inc.
506 Santa Monica Boulevard, Suite 218
Santa Monica, CA 90401

Jeanne Case
C. Case Company, Inc.
7010 West Cerini Avenue
Riverdale, CA 93656

Sherwin Yoelin
Columbine Associates
808 Dolphin Circle
Encinitas, CA 92024

Randall Howard
Central Resources, Inc.
1775 Sherman Street, #2600
Denver, CO 80203

Stephen Brooks
Capitol Oil Corporation
3840 Watt Avenue, Building B
Sacramento, CA 95821

Bruce Webster
Concordia Resources, Inc.
400 Capitol Mall, Suite 900
Sacramento, CA 95814

Robert Sterling
Cirque Resources. LP
475 17th Street, Suite 1600
Denver, CO 60202

Mark Plummer
Chestnut Petroleum, Inc.
2201 N. Central Expressway, Suite 240
Richardson, TX 75080

Wayne Estill
Drilling Exploration & Operating Co.
30423 Canwood Street, #107
Agoura Hills, CA 91301

Mel Riggs
Clayton Williams Energy, Inc.
6 Desta Drive, Suite 6500
Midland, TX 79705

Phil McPherson
Citadel Exploration (COIL)
417 31st Street, Unit A
Newport Beach, CA 92663

Ty Stillman
EOG Resources, Inc.
600 - 17th Street, Suite 1100 N
Denver, CO 80202

Stephen Snow
Commander Oil Co., Ltd.
28212 Kelly Johnson Pkwy, #195
Valencia, CA 91355

Julie Blake
CMO, Inc.
5001 California Avenue, Suite 105
Bakersfield, CA 93309

Michael Decker
Gasco Energy, Inc.
7979 E. Tufts Avenue, Suite 1150
Denver, CO 80237

Bob Cree
Cree Oil Limited
3250 Cherry Avenue
Long Beach, CA 90807

Terry Budden
Compass Global Resources
P.O. Box 2858
Carmel, CA 93921

Richard Field
Golden Gate Oil, LLC
2370 Skyway Drive, Suite 101
Santa Maria, CA 93455

Jim Hutchings
E & T, Limited Liability Company
21520-G Yorba Linda Boulevard, #554
Yorba Linda, CA 92887

Gary Buntmann
Crimson Resources Management
410 Seventeenth Street, #1010
Denver, CO 80202

Chad Hathaway
Hathaway, LLC
P.O. Box 81385
Bakersfield, CA 93380-1385

Phillip Sorbet
ERG Resources, LLC
333 Clay Street, Suite 4400
Houston, TX 77002

Jerome Magee
Emjayco, L.P.
3189 Danville Boulevard, Suite 240
Alamo, CA 94507

David Herley
Herley Kelley Company
P.O. Box 7397
Long Beach, CA 90807

Rusty Risi
General Production Service, Inc.
P.O. Box 344
Taft, CA 93268

Richard Setser
Ferguson Resources, Inc.
P.O. Box 2508
Bakersfield, CA 93303

Fred Holmes
Holmes Western Oil Corporation
4300 Midway Road
Taft, CA 93268

C.E. Olsen
H.T. Olsen Oil & Gas
P.O. Box 579
Paso Robles, CA 93446

Robert Lee
George Kahn Operating Company
25 Fifteenth Place, #601
Long Beach, CA 90802

John Whisler
Incremental Oil and Gas, LLC
600 - 17th Street, Suite 2625-S
Denver, CO 80202

Darren Katic
Hawker Energy
326 S. PPCH, Suite 102
Redondo Beach, CA 90277

Bennett Yannkowitz
Harmon International Petroleum, LLC
P.O. Box 5778
Beverly Hills, CA 90209

Jim Kellogg
K.M.T. Oil Company
P.O. Box 386
Sun City, CA 92586

Joel Noyes
Hess Corporation
1501 McKinney Street
Houston, TX 77010

Renick Sampson
Hellman Properties, LLC
P.O. Box 2398
Seal Beach, CA 90407

Bob Shore
Kern River Holdings, Inc.
7700 Downing Street
Bakersfield, CA 93308

Howard Caywood
Howard E. Caywood, Inc.
500 Hilliard Street
Taft, CA 93268

Bruce Holmes
Holmes Oil Company
24115 Western Minerals Road, POB 219
Maricopa, CA 93252

Chris Garner
Long Beach Gas & Oil
211 East Ocean Boulevard, Suite 500
Long Beach, CA 90802

Dave Jones
Island Energy Partners, LLC
5451 South Durango Drive, Suite 110
Las Vegas, NV 89113

Brian DeWitt
Hoyt Energy, LLC
4520 California Avenue, Suite 310
Bakersfield, CA 93309

Terry English
Mission Oil Company
P.O. Box 81566
Bakersfield, CA 93380

Donald Kelly
Kelpetro Operating, Inc.
P.O. Box 17831
Reno, NV 89511

Rob Graner
J. B. Graner Oil Company
3377 California Avenue
Long Beach, CA 90755

Ernest Filippi
Modus, Inc.
P.O. Box 1809
Porterville, CA 93258

Richard Langdon
KMD Operating Company, LLC
2170 Buckthorne Place, Suite 240
Tomball, TX 77380

Ken Hudson
Kern Bluff Resources, LLC
P.O. Box 3262
La Jolla, CA 92038

Alberto Vasquez
Optima Conservation Resources
13089 Peyton Drive, #C420
Chino Hills, CA 91709

Gregg Kozlowski
MAKOIL, Inc.
25371 Commercentre Drive, Suite 120
Lake Forest, CA 92630

Ron Bowman
LBTH, Inc.
5574 B Everglades Street
Ventura, CA 93003

Bruce Johnston
Pacific Operators Offshore, Inc.
P.O. Box 5565
Oxnard, CA 93031

Dick Mitchell
Mitchell-Grossu Oil Company
5375 E. 2nd Street, Suite 200
Long Beach, CA 90803

Richard Mertz
Mertz, Mr. Richard S.
P.O. Box 50250
Eugene, OR 97405

Blake Davenport
Peak Operator LLC
300 Esplanade Drive, Suite 1810
Oxnard, CA 93036

Joe Sill
O'Brien-Sill
1508 18th Street, Suite 320
Bakersfield, CA 93301

J.M. Kerr
MKCA, LLC
901 Tower Way, Suite 302
Bakersfield, CA 93309

Joe Rose
Petro Resources
1730 Art Street
Bakersfield, CA 93312

CE Peter Allen
P & M Oil
2109 Gundry Avenue
Signal Hill, CA 90755

Douglas Off
Ojai Oil Company
400 W. Ventura Boulevard, Suite 100
Camarillo, CA 93010

Rodger Hunt
Power Run, LLC
P.O. Box 3087
Redondo Beach, CA 90277

Vladimir Katic
Pacific States Energy, LLC
1500 Rosecrans Avenue, Suite 500
Manhattan Beach, CA 90266

Daniel Finley
Pacific Operating Company
P.O. Box 967
Houston, TX 77001

Wolf Regener
R & R Resources, LLC
760 Paseo Camarillo, Suite 350
Camarillo, CA 93010

Karen Wicke
Pearson-Sibert Oil Company
2304 Huntington Drive, #200
San Marino, CA 91108

Steven Coombs
Patriot Resources LLC
1565 Las Canoas Road
Santa Barbara, CA 93105

Ken Teague
Rock Creek Oil, LLC
26000 Commercentre Drive
Lake Forest, CA 92630

Kenneth Hunter
PetroRock, LLC
4700 Stockdale Highway, Suite 120
Bakersfield, CA 93309

Jeff Williams
Petro Capital Resources, LLC
3600 Pegasus Dr., Unit 6
Bakersfield, CA 93308

Louis Witte
Salt Creek Oil, LLC
4521 Witte Street
Bakersfield, CA 93308

Mark Choury
PRE Resources, LLC
1888 Sherman Street, Suite 200
Denver, CO 80203

Peter Dinkelspiel
Pioneer Midway Oil Company
29 Tarry Lane
Orinda, CA 94563

LP Brown, III
Shale Energy International
1070-B West Causeway Approach
Mandeville, LA 70471

Karthik Revana
Reef Ridge Energy Company LLC
17418 Ridge Top Drive
Houston, TX 77090

John Alexander
Pyramid Oil Company
P.O. Box 832
Bakersfield, CA 93302

Gregg Kozlowski
Stone Cabin Resources, LLC
25371 Commercentre Drive, Suite 120
Lake Forest, CA 92630

Ron Surgener
S & S Oil Company
1406 N. Chester Avenue
Bakersfield, CA 93308

H.L. Evans
Ridgeway Corporation
6500 Meadowglade
Moorpark, CA 93021

John McKeown
Synergy Oil & Gas
6433 E. 2nd Street
Long Beach, CA 90803

Renick Sampson
Sampson Operators
301 Ultimo Avenue
Long Beach, CA 90814

Roger Hartley
Sacramento Energy, Inc.
P.O. Box 2551
Bakersfield, CA 93303

George Witter
Temblor Petroleum Company LLC
5201 California Avenue, Suite 340
Bakersfield, CA 93309

Alan Rimel
Sojitz Energy Venture, Inc.
2000 W Sam Houston Prk So, Ste 1450
Houston, TX 77042

Tim Smale
Sequoia Exploration, Inc.
7208 St. Andrews Drive
Bakersfield, CA 93309

Robert Richardson
Towne Exploration Company
5949 Sherry Lane, Suite 1610
Dallas, TX 75255

Brad DeWitt
Summit Energy, LLC
4520 California Avenue, Suite 310
Bakersfield, CA 93309

Pilsbury Winthrop Shaw Pittman LLP
Attn: Norman F. Carlin, Blaine I. Green
Four Embarcadero Center, 22nd Floor
San Francisco, CA 94111

Richard Woodall
Virginia Oil & Land Company
P.O. Box 82515
Bakersfield, CA 93380

John Moran
Tamarack Oil and Gas LLC
1401 Commercial Way, Suite 100
Bakersfield, CA 93309

David Suek
Stephens Production Co - Rockies Div
1825 Lawrence Street, Suite 300
Denver, CO 80202

Daniel Franchi
Watt Mineral Resources
2716 Ocean Park Boulevard, Suite 2025
Santa Monica, CA 90405

Deborah Sycamore
TGC Resources LLC
770 L Street, Suite 932
Sacramento, CA 95814

Warren Treacher
Sun Mountain Oil & Gas
438 Encina Avenue
Davis, CA 95616

Joseph Grigg
American Energy Operations, Inc.
550 N. Brand Boulevard, #1960
Glendale, CA 91203

William Trumbull
Trumbull Oil Properties LLC
333 Tigertail Road
Los Angeles, CA 90049

Harry Barnum
TEG Oil & Gas USA, Inc.
21 S. California Street, Suite 305
Ventura, CA 93001

Gregory Brown
Breitburn Energy
515 S. Flower Street, 48th Floor
Los Angeles, CA 90071

Kerry Zemp
Vista Energy, LLC
1520 Las Canoas Road
Santa Barbara, CA 93105

Rob Thompson
Thompson Energy Resources, LLC
2833 1 Las Cabos
Laguna Niguel, CA 92677

Chris Hall
Drilling & Production Co.
P.O. Box 4120
Torrance, CA 90510

Steven Marshall
Western Energy Production
P.O. Box 7068
Rancho Santa Fe, CA 92067

Tim Smale
U.S. Oil & Gas
7208 St. Andrews Drive
Bakersfield, CA 93309

Donald Macpherson
Macpherson Energy Corporation
100 Wilshire Boulevard, Suite 800
Santa Monica, CA 90401

Hormoz Ameri
Naftex Operating Company
1900 Avenue of the Stars, Suite 2450
Los Angeles, CA 90067

Ramon Elias
Santa Maria Energy
2811 Airpark Drive
Santa Maria, CA 93455

Bill Buss
The Termo Company
3275 Cherry Avenue
Long Beach, CA 90807

Kenneth Hunter
Vaquero Energy, Inc.
P.O. Box 13550
Bakersfield, CA 93389

Wegis and Young
Attn: Greg Wegis
12816 Jomani Dr.
Bakersfield CA 93312

California Department of
Parks and Recreation
1416 9th Street
Sacramento, CA 95814

California Environmental
Protection Agency
1001 I Street
P.O Box 2815
Sacramento, CA 95812-2815

California Director of Government
Affairs
Attn: Bill Allayaud
910 K Street, Suite 300
Sacramento, CA 95814

Earthworks, Oil and Gas Accountability
Project
Attn: Jhon Arbelaez
2150 Allston Way, Suite 460
Berkley, CA 94704

Bruce Conway
B.E. Conway Energy, Inc.
P.O. Box 2050
Orcutt, CA 93457

Frank Komin
California Resources Corporation
111 W. Ocean Boulevard, Suite 800
Long Beach, CA 90802

Stephen Layton
E & B Natural Resources Management
1600 Norris Road
Bakersfield, CA 93308

Linn Energy
Attn: Tim Crawford
JPMorgan Chase Tower
600 Travis, Suite 5100
Houston, TX 77002

Jeff Smith
Maranatha Petroleum, Inc.
1601 "H" Street, Suite 200
Bakersfield, CA 93301

Marc Traut
Renaissance Petroleum, LLC
P.O. Box 20456
Bakersfield, CA 93390

Barry McMahan
Seneca Resources Corp.
1201 Louisiana Street, Suite 400
Houston, TX 77002

Charles Comfort
TRC Operating Company, Inc.
P.O. Box 227
Taft, CA 93268

Larry Huskins Venoco, Inc.
370 17th Street, Suite 3260
Denver, CO 80202

US Army Corps of Engineers
Sacramento District
Attn.: Tambour Eller
1325 J Street
Sacramento, CA 95814-2922

Robert Dowell
Warren Exploration and Production
100 Oceangate, Suite 950
Long Beach, CA 90802

Caltrans – Planning South Branch
Attn: Alec Kimel
1352 West Olive Ave
P.O. Box 12616
Fresno, CA 93778

Dave Cosgrove
Beta Offshore
111 W. Ocean Boulevard, Suite 1240
Long Beach, CA 90802

Jeff Cooper
Cooper & Brain, Inc.
P.O. Box 1177
Wilmington, CA 90748

Rod Eson
Foothill Energy LLC
P.O. Box 131512
Spring, TX 77393

Brad Califf
Longbow, LLC
1701 Westwind, Suite 126
Bakersfield, CA 93301

Johnny Jordan
Matrix Oil Corporation
104 W. Anapamu, Suite C
Santa Barbara, CA 93101

Mike Kranyak
San Joaquin Facilities Management
4520 California Avenue, Suite 300
Bakersfield, CA 93308

Craig Barto
Signal Hill Petroleum
2633 Cherry Avenue
Signal Hill, CA 90755

Stanford Eschner
Trio Petroleum LLC
5401 Business Park South, Suite 115
Bakersfield, CA 93309

Office of Planning and Research State
Clearinghouse and Planning Unit
Attn: Scott Morgan
1400 10th Street P.O. Box 3044
Sacramento, CA 95812

California Native American
Heritage Commission
Capitol Mall, Room 364
Sacramento, CA 95814

Eric Miller
South Valley Farms
15443 Beech Avenue
Wasco, CA 93280

Los Padres Forest Watch
Attn: Jeff Kuyper
P.O. Box 831
Santa Barbara, CA 93102

South Coast Air Quality
Management District
21865 Copley Drive
Diamond Bar, CA 91675

California Natural Resources Agency
Secretary Wade Crowfoot
1416 Ninth Street, Suite 1311
Sacramento, CA 95814

Kern County Water Agency
James M. Beck, General Manager
P.O. Box 58
Bakersfield, CA 93302-0058

Nossaman LLP
Attn: Gregory W. Sanders
18101 Von Karman Ave, Suite 1800
Irvine, CA 92612

State Department of Water Resources
P.O Box 942836
Sacramento, CA 94236-001

Bakersfield Association of Realtors
Ronda Newport, President
2300 Bahamas Drive
Bakersfield, CA 93309

Kern County Water Agency
3200 Rio Miranda Dr.
Bakersfield, CA 93308

Central Valley Flood
Management Planning
3310 El Camino Ave, Rm 151
Sacramento, CA 95821

Politico
Attn: Colby Bermel
925 L St, Suite 150
Sacramento, CA 95814

Association of Irritated Residents
Attn: Tom Frantz
29389 Fresno Ave
Shafter, CA 93263

Natural Resources Defense Council
Attn: David Pettit, Senior Attorney
1314 Second Street
Santa Monica, CA 90401

Holland & Knight LLP
Attn: Jennifer Hernandez, Charles L.
Coleman, Daniel Golub
50 California Street, Ste 2800
San Francisco, CA 94611

Manatt, Phelps & Phillips LLP
Attn: Craig A. Moyer
695 Towne Center Drive, 14th Floor
Costa Mesa, CA 92626

Christian Marsh
Downey Brand LLP
455 Market Street, Suite 1500
San Francisco, CA 94105

Hanna & Morton LLP
Attn: Edward Renwick
444 South Flower Street, Ste 2530
Los Angeles, CA 90071

Shute, Mihaly & Weinburg LLP
Attn: Rachel B. Hooper, Heather Minner
396 Hayes Street
San Francisco, CA 94102

Center for Biological Diversity
Attn: Hollin N. Kretzmann, Clare
Lakewood
1212 Broadway, Ste 800
Oakland, CA 94612

Center on Race, Poverty, and the
Environment
Attn: Caroline Farrell
5901 Christie Avenue, Suite 208
Emeryville, CA 94608

Earthjustice
Attn: Byron Jia-Boa Chan
Colin O'Brien
50 California Street, Suite 500
San Francisco, CA 94111

Natural Resources Defense Council
Attn: Mary K. Umekubo
111 Sutter Street, 21st Floor
San Francisco, CA 94104

Natural Resources Defense Council
Attn: Margaret T. Hsieh
40 West 20th Street, 11th Floor
New York, NY 10011

Sierra Club
Attn: Elizabeth F. Benson
2101 Webster Street, Ste 1300
Oakland, CA 94612

Kern Economic Development Corp
Tamara Baker, Investor Relations
2700 M Street, Suite 200
Bakersfield, CA 93301

Kern River Watermaster
P.O. Box 81435
Bakersfield, CA 93380-1435

Leland Bell Farms, Inc.
David Bell,
1499 East Los Angeles St
Shafter, CA 93263

Kern Inyo Mono Building Trades Council
John Spaulding
200 W Jeffrey St
Bakersfield, CA 93305

State Water Resources Control Board
John Borkovich, P.G., Groundwater
P.O. Box 100
Sacramento, CA 95812-0100

SCS Engineers
Nathan Eady
Dianna Beck
2370 Skyway Drive, Suite 101
Santa Maria CA 93455

Five America North Combustion
Peter Decker
3232 Rio Mirada, Suite C4
Bakersfield, CA 93308

National Association of Royalty Owners
Edward S. Hazard, President
179 Niblick Road, #418
Paso Robles, CA 93446-4845

San Joaquin Valley Air Pollution Control District
Arnaud Marjollet, Director of Permit Services
34946 Flyover CourtBakersfield, CA 93308-9725

Clean Water and Air Matter (CWAM)
12430 Backdrop Court
Bakersfield, CA 93306

CA Department of Fish & Wildlife
Central Region
Julie Vance, Acting Regional Manager
1234 East Shaw Avenue
Fresno, CA 93710

Carolyn Lozo
Oil and Gas GHG Mitigation Branch
Industrial Strategies Division
P.O. Box 2815
Sacramento, CA 95812

Audubon California
Garry George
Renewable Energy Director
4700 Griffin Ave
Los Angeles, CA 90031

Cuyama Basin
Groundwater Sustainability Agency
4900 California Ave, Tower B, 2nd Floor
Bakersfield, CA 93309

Plains All American
Joanne Pruitt
Director, Engineering & Quality Control
333 Clay Street, Ste. 1200
Houston, TX 77002

Steve Greig
Director, Government Affairs
Plains All American Pipeline
5951 Encina Rd., Suite 100
Goleta CA 93110

North Kern Water Storage District
Richard Diamond, General Manager
P.O. Box 81435
Bakersfield, CA 93380-1435

Natural Resource Defense Council
Guilia C. S. Good Stephani,
111 Sutter St., 20th Floor
San Francisco, CA 94104

California Department of Transportation District 6
Alec Kimmel, Associate Transportation Planner
1352 W. Olive Avenue
Fresno, CA 93778-2616

South Valley Farms
Eric Miller, General Manager
15443 Beech Avenue
Wasco, CA 93280

LiUNA
2005 W. Pico Boulevard
Los Angeles, CA 90006

California Attorney General's Office
Yuting (Yvonne) Chi, Deputy Attorney General
Bureau of Environmental Justice
1515 Clay Street, 20th Floor
Oakland, CA 94612

Janet Stockton,
18050 Johnson Rd.
Bakersfield, CA 93314

Committee for a Better Arvin
1241 Bear Mountain Blvd
Arvin, CA 93203

Plains All American Pipeline
James Buchanan
Sr. Environmental Regulatory & Comp
333 Clay Street, Suite 1600
Houston, TX 77002

Home Builders Association of Kern County
P.O. Box 21118
Bakersfield, CA 93390

Kern County Superindendent of Schools
1300 17th Street - City Centre
Bakersfield, CA 93301-4533

Earthjustice
Yana Garcia,
50 California St., Suite 500
San Francisco, CA 94111

Wonderful Orchards
Joseph C. MacIlvaine, President
6801 East Lerdo Highway
Shafter, CA 93263

Sierra Club
Kern-Kaweah Chapter
Babak Naficy, Attorney
1504 Marsh St.
San Luis Obispo, CA 93401

The Center on Race, Poverty & the Environment
Sofia Parino, Senior Attorney
1012 Jefferson Street
Delano, CA 93215

Sequoia Riverland Trust
Adam Livingston,
427 South Garden Street
Visalia, CA 93277

Kern County Farm Bureau
Greg Wegis, President
801 South Mount Vernon Avenue
Bakersfield, CA 93307-2888

Committee for a Better Shafter
209 Golden West Ave
Shafter, CA 93263

Center on Race, Poverty & the Environment
Chelsea Tu
5901 Christie Avenue, Suite 208
Emeryville, CA 94608

Comité Progreso de Lamont
Jose Mireles
9812 San Fernando Street
Lamont, CA 93241

Kern County Cattleman's Assoc.
Attn: Carl F. Twisselman II
9501 West Lokern Road
McKittrick, CA 93251

The Bakersfield Californian
Attn: John Cox
3700 Pegasus Drive
Bakersfield, CA 93308

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DRAFT SUPPLEMENTAL RECIRCULATED ENVIRONMENTAL IMPACT REPORT (SREIR)
(OCTOBER 2020)
CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)
NOTICE OF AVAILABILITY FOR PUBLIC REVIEW

This is to advise that the Kern County Planning and Natural Resources Department has prepared a Draft Supplemental Recirculated Environmental Impact Report (SREIR) (October 2020) for Revisions to the Kern County Zoning Ordinance – 2020 (A), Focused on Oil and Gas Local Permitting. (SCH 2013081079)

As mandated by State law, the public review period for this document is 45 days.

CEQA Guidelines Section 15088.5 (f) (1) provides that when an Environmental Impact Report (EIR) is recirculated, Kern County, as Lead Agency, may require that reviewers submit new comments on the SREIR, and the lead agency need not to respond to those comments received in the earlier circulation period. Kern County will therefore respond in the Final Supplemental Recirculated EIR to new comments during this comment period and through the Planning Commission and Board of Supervisors hearings. The document and documents referenced in the Draft SREIR (October 2020), are available for review at the Planning and Natural Resources Department, 2700 "M" Street, Suite 100, Bakersfield, CA 93301 by appointment or on the Department website (https://kernplanning.com/SREIR2020-oil-gas-zoning-revisions/).

The Kern County Planning and Natural Resources Department will host a virtual public briefing workshop to provide an overview of the document on: **November 10, 2020,** at 1:30 pm., via Microsoft Live Events. Instructions for participating in the virtual public workshop will be available on the Kern County Planning and Natural Resources website (www.kernplanning.com) on November 6, 2020.

A public hearing has been scheduled with the Kern County Planning Commission to receive comments and consider the project for recommendation for approval, conditional approval or denial to the Kern County Board of Supervisors on: **February 11, 2021,** at 7:00 p.m. or soon thereafter, Chambers of the Board of Supervisors, First Floor, Kern County Administrative Center, 1115 Truxtun Avenue, Bakersfield, California. A notice, as required by law will be sent in advance of the hearing and will provide the details for participation. Spanish translation will be provided at the Planning Commission Hearing.

The comment period for this document closes on December 14, 2020.

Project Title: **Draft Supplemental Recirculated Environmental Impact Report (October 2020) for Revisions to the Kern County Zoning Ordinance – 2020 (A), Focused on Oil and Gas Local Permitting**

Project Location: The Project Boundary (Local Permitting Boundary Area) encompasses 3,700 square miles and generally includes the San Joaquin Valley Floor portion of Kern County up to an elevation of 2,000 feet. The boundary includes: west side -the San Luis Obispo County line, north side - the Kings and Tulare county lines, east and south sides - the 2,000-foot elevation contours, squared off to the nearest section line.

Project Description: The purpose of this Supplemental Recirculated Environmental Impact Report is to provide compliance with CEQA for the reconsideration by the Planning Commission and Board of Supervisors of the Zoning Ordinance revisions focused on Oil and Gas Local Permitting.

The proposed Project is a reconsideration of revisions to various Chapters of Title 19 Kern County Zoning Ordinance to implement a new permit process for oil and gas activities. The revisions include new site development standards and review processes for all oil and gas exploration, extraction, operations, and production activities in unincorporated Kern County by:

(a) Removing the "Unrestricted Drilling" Section in Chapter 19.98 and updated "Drilling by Ministerial Permit" and "Drilling by Conditional Use Permit" Sections;

(b) Establishing "Tier Area" maps to address different land uses and zone districts where oil and gas activities occur and are proposed to occur in the future;

(c) Establishing an Oil and Gas Conformity Review and Minor Activity Review, as part of the "Drilling by Ministerial Permit" Section in Chapter 19.98, to ensure compliance with all applicable Development and Implementation Standards and Conditions;

(d) Establishing Development and Implementation Standards and Conditions Section in Chapter 19.98;

(e) Establishing requirements for site plan sign-off by owners of the surface and minerals for split estate ownership;

(f) Revising additional Chapters of the Zoning Ordinance to ensure consistency with the new requirements of this SREIR. These Chapters include: 19.08 – Interpretations and General Standards, 19.48 – Drilling Island (DI) District, 19.50 – Floodplain Primary District, 19.66 – Petroleum Extraction (PE) Combining District, 19.81 - Outdoor Lighting (Dark Skies Ordinance), 19.88 – Hillside Development, 19.102 – Permit Procedures, and 19.108 – Nonconforming Uses, Structures, and Lots.

Proposed 2020 revisions to Title 19 – Kern County Zoning Ordinance are the same as the ordinance adopted by the Board of Supervisors in November 09, 2015, and implemented until March 25, 2020, with the exception of the following changes:

- Update of names of County departments and State agencies that have changed since 2015, reference to this SREIR, and implementation details.
- Clarification of process for monitoring Split Estate 120 day process.
- Adjustment of Tier Maps for technical geographic information system (GIS) errors identified from 2015 adoption.

Background

The County prepared and circulated a Draft Environmental Impact Report (DEIR) and Final Environmental Impact Report (FEIR) for amendments to Title 19 of the Kern County Zoning Ordinance (Ordinance), Chapter 19.98 (Oil and Gas Production) and related sections of the Ordinance in 2015. The Kern County Board of Supervisors unanimously approved the Ordinance amendments and certified the FEIR on November 9, 2015 (2015 FEIR). Several parties filed lawsuits challenging the adequacy of the certified 2015 FEIR, and the cases were consolidated in the Kern County Superior Court. On April 20, 2018, the Court issued a judgment upholding 2015 FEIR, except for two issues. The judgment did not vacate any portion of the Ordinance or 2015 FEIR. The County subsequently prepared and circulated a Draft Supplemental Environmental Impact Report (2018 SEIR) in response to the judgment. The SEIR was certified by the County Board of Supervisors on December 11, 2018, and was not legally challenged.

Several parties appealed the Superior Court judgment. In October 2019, the Appellate Court rejected constitutional claims against the Ordinance amendments. On February 25, 2020, the Appellate Court issued an opinion that upheld the Superior Court judgment and the adequacy of the certified 2015 FEIR except for "five areas in which the EIR did not comply with CEQA: (1) mitigation of water supply impacts; (2) impacts from PM2.5 emissions; (3) mitigation of conversion of agricultural land; (4) noise impacts; and (5) recirculation of the Multi-Well Health Risk Assessment (MWHRA) for public review and comment." The opinion set aside the previously approved Ordinance amendments and the certification of the 2015 FEIR. The opinion further directed the County, "in the event it decides to present the Ordinance (in its present or a modified form) to the Board for approval, to correct the CEQA violations identified in this opinion," to prepare "a revised EIR correcting the CEQA violations," and to prepare and publish "responses to the comments received before certifying the revised EIR and reapproving the Ordinance." The County Board of Supervisors rescinded the approved Ordinance amendments and decertified the 2015 FEIR on May 19, 2020 (Resolution 2020-116). The purpose of this Supplemental Recirculated Environmental Impact Report is to provide compliance for CEQA.

A Draft SREIR (August 2020) was prepared, incorporating agency and public comments received during the NOP/IS and Scoping Process, and circulated August 3, 2020, for a 45 day public review period. This is the second circulation of a DSREIR for this process and incorporates all comments received on the Draft SREIR (August 2020) and the full document circulated August 2020. This SREIR (October 2020) shows all text changes from the earlier SREIR (August 2020) as italics, with text additions underlined and text deletions as strikeouts.

Anticipated Significant Impacts on Environment: Aesthetics, Agricultural Resources, Air Quality; Biological Resources; Cultural Resources, Greenhouse Gas, Energy, Hydrology and Water Quality, Noise, and Utilities and Service Systems.

Document can be viewed online at: https://kernplanning.com/SREIR2020-oil-gas-zoning-revisions/

For further information, please contact: Cindi Hoover, Planner III at (661) 862-8629 or hooverc@kerncounty.com

AMERICANS WITH DISABILITIES ACT
(Government Code Section 54953.2)

Disabled individuals who need special assistance to attend or participate in a Kern County Planning and Natural Resources virtual workshop may request assistance at the Kern County Planning and Natural Resources Department, 2700 "M" Street, Suite 100, Bakersfield, California 93301, or by calling Cindi Hoover at (661) 862-8629. Every effort will be made to reasonably accommodate individuals with disabilities by making meeting materials available in alternative formats. Requests for assistance should be made five (5) working days in advance whenever possible.

Lorelei H. Oviatt
LORELEI OVIATT, AICP, Director
Planning and Natural Resources Department

To be published once only on next available date and as soon as possible

The Bakersfield Californian
Daily Independent
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Mojave Desert News
Tehachapi News
Rosamond Weekly News
Daily Midway Driller

CLH

cc: County Clerk (2) (with fee)
All Supervisorial Districts
Environmental Status Board
Planning Commissioners

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Notice of Completion & Environmental Document Transmittal

Mail to: State Clearinghouse, P. O. Box 3044, Sacramento, CA 95812-3044 (916) 445-0613
For Hand Delivery/Street Address: 1400 Tenth Street, Sacramento, CA 95814

SCH # 2013081079

Project Title: Revisions to Title 19 – Kern County Zoning Ordinance (2020A) Focused on Oil and Gas Local Permitting

Lead Agency: Kern County Planning and Natural Resources Department
Contact Person: Cindi L. Hoover
Mailing Address: 2700 "M" Street Suite 100
Phone: (661) 862-8629
City: Bakersfield
Zip: 93301-2323
County: Kern

Project Location: County: Kern
City/Nearest Community: Multiple
Cross Streets: n/a
Zip Code Multiple
Lat. / Long.:
Total Acres: 3,700 square miles
Assessor's Parcel No.: Multiple
Section: Multiple Twp.: Multiple Range: Multiple Base:
Within 2 Miles: State Hwy #: 99, 58, 43, 46, 119, 223, 204, 33 Waterways: Kern River
Airports: Multiple Railways: Multiple Schools: Multiple

Document Type:

CEQA:
- ☐ NOP
- ☐ Early Cons
- ☐ Neg Dec
- ☐ Mit Neg Dec
- ☐ Draft EIR
- ☒ Supplement/Subsequent EIR
- (Prior SCH No.) 2013081079
- Other

NEPA:
- ☐ NOI
- ☐ EA
- ☐ Draft EIS
- ☐ FONSI

Other:
- ☐ Joint Document
- ☐ Final Document
- ☐ Other

Local Action Type:

- ☐ General Plan Update
- ☐ General Plan Amendment
- ☐ General Plan Element
- ☐ Community Plan
- ☐ Specific Plan
- ☐ Master Plan
- ☐ Planned Unit Development
- ☐ Site Plan
- ☐ Rezone
- ☐ Prezone
- ☐ Use Permit
- ☐ Land Division (Subdivision, etc.)
- ☐ Annexation
- ☐ Redevelopment
- ☐ Coastal Permit
- ☒ Amendment to Zone Ord.

Development Type:

- ☐ Residential: Units ____ Acres ____
- ☐ Office: Sq.ft. ____ Acres ____ Employees ____
- ☐ Commercial: Sq.ft. ____ Acres ____ Employees ____
- Industrial: Sq.ft. ____ Acres ____ Employees ____
- ☐ Educational
- ☐ Recreational
- ☐ Water Facilities: Type ____ MGD ____
- ☐ Transportation: Type
- ☐ Mining: Mineral
- ☐ Power: Type ____ MW ____
- ☐ Waste Treatment: Type ____ MGD ____
- ☐ Hazardous Waste: Type
- ☒ Other: Oil and Gas Exploration and Production

Project Issues Discussed in Document:

- ☐ Aesthetic/Visual
- ☒ Agricultural Land
- ☒ Air Quality
- ☐ Archeological/Historical
- ☐ Biological Resources
- ☐ Coastal Zone
- ☐ Drainage/Absorption
- ☐ Economic/Jobs
- ☐ Fiscal
- ☐ Flood Plain/Flooding
- ☐ Forest Land/Fire Hazard
- ☐ Geologic/Seismic
- ☐ Minerals
- ☒ Noise
- ☐ Population/Housing Balance
- ☒ Public Services/Facilities
- ☐ Recreation/Parks
- ☐ Schools/Universities
- ☐ Septic Systems
- ☐ Sewer Capacity
- ☐ Soil Erosion/Compaction/Grading
- ☐ Solid Waste
- ☐ Toxic/Hazardous
- ☐ Traffic/Circulation
- ☐ Vegetation
- ☐ Water Quality
- ☒ Water Supply/Groundwater
- ☐ Wetland/Riparian
- ☐ Wildlife
- ☐ Growth Inducing
- ☐ Land Use
- ☒ Cumulative Effects
- ☐ Other

Present Land Use/Zoning/General Plan Designation: Developed and undeveloped land in Kern County. Current Zoning Classifications and General Plan Map Code Designations to remain the same.

Project Description: The proposed project is the preparation of a Supplemental Recirculated EIR (SREIR) (October 2020) for reconsideration of Revision to Title 19 of the Kern County Zoning Ordinance (2020 A) (Ordinance) for local permitting for oil and gas focused on Chapter 19.98 (Oil and Gas Production). On November 9, 2015 the Kern County Board of Supervisors approved amendments to Title 19 of the Kern County Zoning Ordinance, 19.98(Oil and Gas Production) and related sections of the Kern County Zoning Ordnance (Ordinance) to address oil and gas exploration and operation activities within the Project Area in greater detail. The Board of Superiors also certified an Environmental Impact Report (EIR) analyzing the impacts of the amendments, and the implementation of future oil and gas development activities expected to be undertaken pursuant to the amended Ordinance in accordance with the California Environmental

Quality Act (CEQA). Effective March 25, 2020, the previously-approved Ordinance amendments and certified EIR were set aside pursuant to an opinion issued by the Fifth Appellate District of the California Court of Appeal (Appellate Court) on February 25, 2020. The Appellate Court opinion rejected most of the legal challenges to the certified EIR except for five "CEQA violations" that the County must correct "in the event it decides to present the Ordinance (in its present or a modified form) to the Board for reapproval."

A Draft SREIR (August 2020) was prepared, incorporating agency and public comments received during the NOP/IS and Scoping Process, and circulated August 3, 2020 for a 45 day public review period. This is the second circulation of a DSREIR for this process and incorporates all comments received on the Draft SREIR (August 2020) and the full document circulated August 2020. The County is preparing this SREIR to provide analysis to address the CEQA deficiencies found by the Appellate Court decision. The Draft SREIR will provide compliance for CEQA for reconsideration by the Planning Commission and Board of Supervisors of the Zoning Ordinance revisions focused on Oil and Gas Local Permitting.

Reviewing Agencies Checklist

Lead Agencies may recommend State Clearinghouse distribution by marking agencies below with and "**X**".
If you have already sent your document to the agency please denote that with an "S".

S	Air Resources Board		Office of Emergency Services
	Boating & Waterways, Department of	S	Office of Historic Preservation
S	California Highway Patrol		Office of Public School Construction
	CalFire	S	Parks & Recreation
S	Caltrans District # 6 & 9		Pesticide Regulation, Department of
S	Caltrans Division of Aeronautics	S	Public Utilities Commission
S	Caltrans Planning (Headquarters)	S	Regional WQCB # Lahontan & Central Valley
	Central Valley Flood Protection Board	S	Resources Agency
	Coachella Valley Mountains Conservancy		S.F. Bay Conservation & Development Commission
	Coastal Commission		San Gabriel & Lower L.A. Rivers and Mtns Conservancy
	Colorado River Board		San Joaquin River Conservancy
S	Conservation, Department of		Santa Monica Mountains Conservancy
	Corrections, Department of	S	State Lands Commission
	Delta Protection Commission		SWRCB: Clean Water Grants
	Education, Department of	S	SWRCB: Water Quality
S	Energy Commission		SWRCB: Water Rights
S	Fish & Game Region # Fresno		Tahoe Regional Planning Agency
S	Food & Agriculture, Department of	S	Toxic Substances Control, Department of
	General Services, Department of	S	Water Resources, Department of
	Health Services, Department of		
	Housing & Community Development		Other
S	Integrated Waste Management Board		Other
S	Native American Heritage Commission		

Local Public Review Period (to be filled in by lead agency)

Starting Date October 30, 2020 Ending Date December 14, 2020

Lead Agency (Complete if applicable):

Consulting Firm:
Address:
City/State/Zip:
Contact:
Phone:

Applicant:
Address:
City/State/Zip:
Phone:

Signature of Lead Agency Representative: **Date: 10/30/2020**

Authority cited: Section 21083, Public Resources Code. Reference: Section 21161, Public Resources Code.

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NOTE TO REVIEWER OF ELECTRONIC FILES: To assist you in reviewing this electronic document, *bookmarks* and/or *links* have been provided for easier navigation between sections. When available, bookmarks are located in the panel to the left. Links are shown in **BLUE** in the Table of Contents. Clicking on either the bookmarks or links will take you to the selected item. This document may consist of multiple linked PDF files. If saving this document to your computer, you must save all corresponding files to one folder on your hard drive to maintain the link connections.

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The following volumes are included on the ~~CD~~ *flash drive* that is inserted in the front cover of Volume 1 of this SREIR.

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B - Health Risk Assessments

B-1 - Supplemental Health Risk Assessment Technical Memorandum (October 2020)

C - Oil and Gas Emission Reduction Agreement (20160168) KC Agreement # 890-2016

D - Supplemental Water Supply Baseline Technical Report (2020)

E - Supplemental Noise Technical Memorandum (October 2020)

F - Sensitive Receptor Community Analysis (October 2020)

G - Comments Received on the Draft SREIR (August 2020)

VOLUME 3

Draft Environmental Impact Report: Revisions to the Kern County Zoning Ordinance – 2015 (C) Focused on Oil and Gas Local Permitting, Chapters 1 through 11

VOLUME 4

Draft Environmental Impact Report: Revisions to the Kern County Zoning Ordinance – 2015 (C) Focused on Oil and Gas Local Permitting, Appendices

VOLUME 5

Final Environmental Impact Report: Revisions to the Kern County Zoning Ordinance – 2015 (C) Focused on Oil and Gas Local Permitting, Chapter 7 – Response to Comments

VOLUME 6

Final Environmental Impact Report: Revisions to the Kern County Zoning Ordinance – 2015 (C) Focused on Oil and Gas Local Permitting, Appendices to Chapter 7 – Response to Comments

VOLUME 7

Final Environmental Impact Report: Revisions to the Kern County Zoning Ordinance – 2015 (C) Focused on Oil and Gas Local Permitting, Chapter 12 Consolidated FEIR

VOLUME 8

Final Supplemental Environmental Impact Report for Approved Amendments to the Kern County Zoning Ordinance – 2015 (C) Focused on Oil and Gas Local Permitting~~, *2018 Draft Supplemental EIR*~~

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Executive Summary

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Chapter 1
Executive Summary

1.1 Introduction

The Kern County (County) Board of Supervisors on November 9, 2015, after a public process of workshops, circulation of the Notice of Preparation and Draft Environmental Impact Report (DEIR), and consideration at a noticed Planning Commission hearing with a recommendation to the Board for adoption, approved changes to Title 19 of the Kern County Zoning Ordinance to implement local permitting of oil and gas activities. The Ordinance contained extensive new protective measures for health and safety of communities and residents while providing for a clear and certain process for permitting. A history of that permitting, which commenced on December 9, 2015, and ended March 25, 2020, can be found in Section 1.3.1, History of Local Oil and Gas Permitting, below.

Several parties filed lawsuits challenging the adequacy of the certified Environmental Impact Report (EIR), and the cases were consolidated in the Kern County Superior Court. On April 20, 2018, the Court issued a judgment upholding the EIR in its entirely except for requiring supplemental environmental review under the California Environmental Quality Act (CEQA) for two issues. The judgment did not vacate any portion of the Ordinance or the EIR. The County subsequently prepared and circulated a draft Supplemental Environmental Impact Report (SEIR) in response to the judgment. The SEIR was certified by the County Board of Supervisors on December 11, 2018, and was not legally challenged.

Several parties appealed the judgment to the Fifth Appellate District of the California Court of Appeal (Appellate Court). In October 2019 the Appellate Court rejected certain constitutional claims against the Ordinance amendments. On February 25, 2020, the Appellate Court issued an opinion that upheld the judgment and the adequacy of the certified EIR except for “five areas in which the EIR did not comply with CEQA: (1) mitigation of water supply impacts; (2) impacts from PM2.5 emissions; (3) mitigation of conversion of agricultural land; (4) noise impacts; and (5) recirculation of the Multi-Well Health Risk Assessment for public review and comment.” The opinion directed the Superior Court to set aside the certification of the EIR and the previously approved Ordinance amendments, effective March 25, 2020. The opinion states that “pending CEQA compliance, the County will return to the regulatory scheme in place prior to the ordinance's adoption.” The opinion further directs the County, “in the event it decides to present the Ordinance (in its present or a modified form) to the Board for approval, to correct the CEQA violations identified in this opinion,” to prepare “a revised EIR correcting the CEQA violations,” and to prepare and publish “responses to the comments received before certifying the revised EIR and reapproving the Ordinance.”

Under direction of the court the Board of Supervisors on May 19, 2020 (Board Resolution 2020-116) rescinded the 2015 Final Environmental Impact Report (FEIR) and Ordinance and reinstated the current ordinance. This current ordinance (described in Section 1.3.1) has few protective measure, has no required Kern County permit, and completely depends on the California Geologic Energy Management Division (CalGEM) permit for health and safety protections for land use. The Kern County Board of Supervisors has jurisdiction over land use, while CalGEM has authority for the extraction and exploration practices under the ground for oil and gas. The Board, concerned for both the land use considerations and jurisdiction to protect public health and safety and the economic stability of the industry, directed the Planning and Natural Resources Department to correct the deficiencies identified by the court, review the Ordinance for any necessary changes, and commence the public process for review and reconsideration.

The purpose of this Supplemental Recirculated Environmental Impact Report (SREIR) is to provide analysis to address the CEQA deficiencies found by the Appellate Court decision and provide compliance for CEQA for reconsideration by the Planning Commission and Board of Supervisors of the Zoning Ordinance revisions focused on Oil and Gas Local Permitting.

This Draft SREIR has been prepared by Kern County as the Lead Agency under CEQA. It provides information about the environmental setting and impacts of the Project and alternatives. It informs the public about the Project and its impacts and provides information to meet the needs of local, state, and federal permitting agencies that are required to consider the Project. The SREIR will be used by the County to determine whether to approve the proposed amendment to Chapter 19.98 and related chapters of the Kern County Zoning Ordinance. It is based on the information contained in the 2015 FEIR, which is provided as Volume 3 of this SREIR.

The public process for this project has resulted in two draft SREIRs that have been prepared and circulated for public comment. The first draft SREIR was completed in August 2020 and is referred to as the SREIR (August 2020), and this second draft SREIR has been released in October 2020 and is referred to as the SREIR (October 2020). This SREIR (October 2020) shows all text changes from the earlier SREIR (August 2020) as italics, with text additions underlined and text deletions as strikeouts. Unless otherwise noted, all references to the SREIR refer to this SREIR (October 2020).

This Executive Summary summarizes the requirements of the CEQA Statute and Guidelines, provides an overview of the Project and alternatives, identifies the purpose of the Draft SREIR, outlines the potential impacts of the Project and the recommended mitigation measures, and discloses areas of controversy and issues to be resolved for both this SREIR and the 2015 FEIR

1.2 Project Summary

The Project is to amend Chapter 19.98 and related chapters of the Kern County Zoning Ordinance to provide for local permitting of Oil and Gas Activities. This project includes a limitation on the number of annual permits that can be issued and the development scenario for oil and gas activities in Kern County, which is summarized in Section 1.5.4, below. The Draft SREIR, once certified, will be used to satisfy the CEQA requirements for the following discretionary approvals

1. Amendment of Kern County Zoning Ordinance Chapter 19.98 – Oil and Gas Activities and related chapters for consistency with the new provisions of Chapter 19.98;
2. Approval of the proposed Project Mitigation Measure Monitoring Program;
3. Approval of the CEQA Findings pursuant to CEQA Guidelines Sections 15091; and
4. Approval of a Statement of Overriding Consideration CEQA Guidelines Section 15093.

The following agencies are included as Responsible Agencies under the provisions of CEQA and could utilize the certified FEIR for oil and gas activities:

1. California Geologic Energy Management Division (CalGEM) permitting of oil and gas activities, including well stimulation, in the Project Area;
2. San Joaquin Valley Air Pollution Control District (SJVAPCD) permitting for oil and gas-related equipment/facilities, including, for example, boilers, steam generators, process heaters, flares, tanks, and portable equipment;
3. Central Valley Regional Water Quality Control Board Waste Discharge Requirements (WDRs) and Clean Water Act section 401 Water Quality Certifications and WDR waivers;
4. California Department of Fish and Wildlife incidental take permits;
5. California Department of Toxic Substances Control oversight of routine management and cleanup of non-petroleum spills and releases;
6. California Department of Transportation encroachment permits;
7. Central Valley Flood Protection Control Board encroachment permits; and
8. Kern County Water Agency and other water districts' permits for water-related uses.

1.3 Project History

1.3.1 History of Oil & Gas Extraction in Kern County

Prior to the 2015 FEIR and adoption of a comprehensive oil and gas permitting application, oil and gas operations were authorized as "unrestricted drilling" with no County permit required, in County lands zoned for Exclusive Agriculture (A), Limited Agriculture (A-1), Medium Industrial (M-2), Heavy Industrial (M-3), and Natural Resource (NR). This activity was subject to compliance with specified conditions and standards that augment the State agencies and Air District requirements, as well as applicable fire and safety ordinances and regulations of the County. In these Zoning Districts, no County review or permit is required for the drilling of any steam injection well, steam drive well, service well, or any well intended for the exploration for, or development or production of, oil, gas, and other hydrocarbon substances, or for any related ancillary equipment, structure, or facility used as part of the oil and gas production process. This is the ordinance that is currently in place due to the recession of the Kern County Title 19 Ordinance for Local Oil and Gas Permitting (2015-C) by the Board of Supervisors on May 19, 2020 (Board Resolution 2020-116).

Certain zone districts (Section 19.98.030) provide for drilling by “ministerial permit.” A ministerial permit requires an application and review process, but the County does not impose site-specific conditions in such permits, and the applicant is entitled to receive the permit once it demonstrates that relevant standards are met. Ministerial permits are required in the Light Industrial (M-1) and Recreation-Forestry (RF) districts, subject to specified development standards, which also apply in Drilling Island (DI) zone districts and Petroleum Extraction (PE) combining districts. Under this ministerial permit provision, no injection well and no well for the exploration for, or development or production of, oil or gas or other hydrocarbon substances may be drilled, and no related accessory equipment, structure, or facility may be installed in the above-referenced zone categories, until an application for a plot plan review has been submitted to and approved by the Kern County Planning Director; the application must show consistency with the development standards set out in Section 19.98.050.

A Conditional Use Permit (CUP), which is a discretionary permit process allowing the County to establish site-specific conditions and, under appropriate circumstances, deny an application, is required for oil or gas exploration or production in all residential districts, including the Estate District (E), as well as in the Low-, Medium-, and High-Density Residential Districts (R-1, R-2, and R-3, respectively). A CUP is also required in commercial districts, including the Commercial Office District (CO), Neighborhood Commercial District (C-1), General Commercial District (C-2), and the Highway Commercial District (CH), as well as in the Platted Lands District (PL). The CUP provisions are set out in Section 19.104.

Oil or gas exploration or production is prohibited in the Mobile Home Park District (MP) (Section 19.26.040) and in the Open Space District (OS) Zoning Districts (Section 19.44.040).

A full description of the requirements currently in place, including the development standards, can be found in Section. 3.2.5, Kern County Zoning Ordinance of this SREIR.

In 2012 representatives of the oil and gas industry associations—specifically, the California Independent Petroleum Association (CIPA), the Independent Oil Producers Agency (IOPA), and the Western States Petroleum Association (WSPA) (collectively, “Project Proponents”)—requested an amendment to Chapter 19.98 (Oil and Gas Production) and related chapters of the Kern County Zoning Ordinance to include additional provisions for local permitting of oil and gas activities. Under Chapter 19.112, amendments to the text of the Zoning Title of the Kern County Zoning Ordinance can only be initiated by the Kern County Board of Supervisors. The request was considered in a public hearing before the Board of Supervisors on January 22, 2013, and the Board directed Planning and Community Development Staff (now renamed Planning and Natural Resources Department) to proceed with processing the requested amendments. After a public process of workshops, circulation of the Notice of Preparation and Draft EIR and consideration at a noticed Planning Commission hearing with a recommendation to the Board for adoption, on November 9, 2015, the County certified a Final EIR and approved the proposed Ordinance revisions as amendments to Title 19. The requirement that any new well, rework, well stimulation, or pipelines, as well as changes to existing facilities, now needed a permit first from the Kern County Planning and Natural Resources Department before applying to CalGEM for a permit, was commenced December 9, 2015, and ended March 25, 2020.

Beginning in December 2016, an annual report has been prepared and filed on the agenda with the Kern County Board of Supervisors, as well as posted on the department website. https://kernplanning.com/planning/kern-county-oil-gas-permitting-3-2/. The Department Oil and Gas Permitting Division managed the program through an online portal (Accela) program linked to the Building Inspection Division and other Planning functions. Various materials were prepared to assist applicants in submitting complete, compliant applications, including the Permitting Handbook and Small Producers Handbook. The annual reports contained the statistics for the program since commencement on December 9, 2015. Under the court order, the Department ended processing any permits on March 25, 2020. Tables 1-1 and 1-2 summarize the permitting done under the approved zoning ordinance amendments.

Table 1-1 Total Approved and Issued Permits

	Issued					
Permit Type	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
Oil and Gas Conformity Review	1,122	1,891	1,055	1,208	585	5,861
Minor Reworks	N/A	399	903	880	432	2,614
Minor Activity Review	72	105	151	177	117	622
TOTAL	1,194	2,395	2,109	2,265	1,134	9,097

Table 1-2 Mitigation Funds From Approved Permits

Mitigation Measure	FEE CODE	AMOUNT					
		2016	2017	2018	2019	2020	Total
4.16-1	POG050 – Roadway Maintenance/Improvements	$388,700.00	$1,444,500.00	$2,805,000.00	$2,769,000.00	$2,122,500.00	$9,529,700.00
4.14-1	POG051 – Firefighting Equipment	$162,450.00	$380,700.00	$299,550.00	$47,026.00	-	$889,726.00
4.5-3	POG052 – Paleontological Resource	$10,300.00	$37,950.00	$61,800.00	$59,200.00	$33,525.00	$202,775.00
4.14-2	POG053 – Rural Crimes Unit	$432,225.00	$1,065,050.00	$1,427,575.00	$1,312.975.00	$691,819.60	$4,929,644.60
Done 4.2-1	POG054 - Mitigation of Agricultural Land Replacement	$30,996.00	$20,817.00	$66,247.67	$28,242.00	-	$146,302.67
4.3-8	POG055 - Air Quality Impacts	$3,329,332.87	$14,443,711.93	$32,268,388.27	$38,896,506.00	$25,161,192.61	$114,099,131.68
4.3-8	POG057 – SJVAPCD Fee	$138,722.20	$584,744.32	$1,301,032.45	$1,554,270.00	$991,502.98	$4,570,271.95
4.4-16	POG056 - Biological Resources Mitigation	$60,502.50	$349,985.29	$431,815.40	$505,495.00	$362,193.94	$1,709,992.13
	Total	$4,553,228.57	$18,327,458.54	$38,661,408.79	$45,172,714.00	$29,362,734.13	$136,077,544.03

1.3.2 Revision to Title 19-Kern County Zoning Ordinance (2020)

The proposed 2020 revisions to Title 19 – Kern County Zoning Ordinance are the same as the ordinance adopted by the Board of Supervisors November 9, 2015, and implemented until March 25, 2020, with the exception of the following changes:

- Update of names of County departments and State agencies that have changed since 2015, reference to this SREIR, and implementation details;
- Clarification of the process for monitoring Split Estate 120-day process; and
- Adjustment of Tier Maps for technical geographic information system errors identified from 2015 adoption.

1.4 Purpose and Use of the Draft SREIR

An EIR is a public informational document used in the planning and decision-making process. This SREIR analyzes the environmental impacts of the proposed Project. The Kern County Planning Commission and Board of Supervisors will consider the information in the SREIR, including public comments and staff responses to those comments, during the public hearing process. As amending the Zoning Ordinance is a legislative action, the final decision will be made at the Board of Supervisors' public hearing, where the Project may be approved, conditionally approved, or denied.

The purpose of this SREIR is to correct deficiencies identified by the court in the 2015 FEIR and analyze potential impacts to agricultural resources, air quality, ($PM_{2.5}$ and multi-well health risk assessment) hydrology and water quality (groundwater supply and Sustainable Groundwater Management Act (SGMA), noise, and utilities and service systems (groundwater supply and SGMA. ~~To support this purpose, this SREIR identifies~~ <u>*This SREIR will provide the following information and analysis:*</u>

- The significant potential impacts of a proposed project on the environment in relation to the five topic areas identified by the Courts and the manner in which those significant impacts can be avoided or mitigated;
- Any unavoidable adverse impacts that cannot be mitigated in relation to the five topic areas identified by the Courts; and
- Reasonable and feasible alternatives to the Project that would eliminate any significant adverse environmental impacts or reduce the impacts in relation to the five topic areas identified by the Courts to a less than significant level.

An EIR also discloses growth-inducing impacts, impacts found not to be significant, and significant cumulative impacts of past, present, and reasonably anticipated future projects.

CEQA requires an EIR to reflect the independent judgment of the lead agency regarding the impacts, the level of significance of the impacts both before and after mitigation, and mitigation measures proposed to reduce the impacts. A DEIR is circulated to public agencies, special districts, responsible and trustee agencies that manage resources affected by the project, and interested agencies and individuals. The purposes of public and agency review of a DEIR include sharing expertise, disclosing agency analyses, checking for accuracy, detecting omissions, discovering public concerns, and soliciting counterproposals.

The first draft SREIR (August 2020) was issued for a 45-day public comment period. During the public comment period, a virtual public workshop was held to explain the Project and public process and receive written comments. Spanish translation was available for listeners to the virtual workshop, as well as closed captioning. The virtual workshop did not provide an opportunity for oral comments in any language. Nine comment letters were received during the public comment period, and one additional comment letter (dated October 2, 2020) was received after the 45-day period ended. During the virtual public workshop, nine participants made written comments. All comments received on the SREIR (August 2020) are included in Appendix G to this SREIR (October 2020).

Comments on the SREIR (August 2020) addressed multiple topics. A list of comments, the full text of all written comments received, and a transcript of the public workshop are included in Appendix G of this SREIR (October 2020). Some comments included submittal of technical reports. This SREIR (October 2020) includes additional analysis and text modifications to address the technical reports submitted in comments in response to the earlier SREIR (August 2020), a full analysis of the alternative for a 2,500-foot setback from sensitive receptors, and additional analyses and mitigation from the lead agency.

To provide members of the public and interested parties with an opportunity to review this additional analysis and text changes in this second SREIR (October 2020), a second 45-day public comment period and public workshop will be provided. Responses to comments made on the initial draft SREIR (August 2020), as well as this second Draft SREIR (October 2020), will be provided in a single comprehensive Response to Comments document (Chapter 7) as part of the Final SREIR for consideration by the Planning Commission and Board of Supervisors.

Reviewers of this *draft SREIR (October 2020)* should focus on the sufficiency of the document in identifying and analyzing the possible impacts on the environment and ways in which the significant effects of the Project might be avoided or mitigated. Comments are most effective when they suggest additional and specific alternatives or mitigation measures that would provide better ways to avoid or mitigate significant environmental effects. *For reading purposes, changes to the SREIR (August 2020) are all italicized, and text additions are underlined and text deletions are strikeouts.*

1.4.1 Structure of this SREIR

As a Supplemental Recirculated document with a focus on updated analysis of five resource topics identified by the Courts, this document is structured to include the 2015 FEIR as a reference and referral resource, and that full document is included as Volumes 3 through 7. The following outline is provided to assist the reader in reviewing the document.

Chapter 2, Introduction: Provides a background of the Project and the legal history leading to the need for this SREIR.

Chapter 3, Project Description: Contains a full description of all aspects of Project implementation for oil and gas activities.

Chapter 4, Environmental Setting, Impacts, and Mitigation Measures - Supplemental Analysis: Contains the topic resource areas that are the subject of this SREIR, numbered for easy reference to the 2015 FEIR and a section on clarification of other mitigation measures not identified as deficient by the court.

4.2, Agriculture and Forest Resources

4.3, Air Quality

4.9, Hydrology and Water Quality

4.12, Noise

4.17, Utilities and Service Systems

4.18, Supplemental Analysis – Clarification of Mitigation Measures

All sections required for compliance with CEQA have been included in this SREIR.

1.5 Project Overview

This section describes the local and regional setting, surrounding land uses, Project objectives, and Project characteristics. The Project is described in further detail in Chapter 3, Project Description. The proposed revisions to the Zoning Ordinance are included in Chapter 3, Project Description as Attachment A.

1.5.1 Local and Regional Setting

Kern County is California’s third-largest county in terms of land area, encompassing 8,202 square miles. Located at the southern end of the Central Valley, Kern County serves as the gateway to southern California, the San Joaquin Valley, and California's high desert. The geography of Kern County is diverse, containing mountainous areas, agricultural lands, and desert areas.

Kern County is bounded by Kings, Tulare, and Inyo Counties on the north, San Bernardino County on the east, Los Angeles and Ventura Counties on the south, and Santa Barbara and San Luis Obispo Counties on the west. Kern County includes eight incorporated cities within the portion of the County located in the San Joaquin Valley including Arvin, Bakersfield, Delano, Maricopa, McFarland, Shafter, Taft, and Wasco. Oil and gas exploration and development activities have historically occurred in the San Joaquin Valley Floor portion of the County and are likely to continue to occur in the same vicinity. For this reason, the SREIR evaluates potential impacts of future oil and gas exploration and production activities within a defined boundary.

The Kern County General Plan (KCGP) describes the San Joaquin Valley region as "the southern San Joaquin Valley below an elevation of 1,000 feet mean sea level (MSL)" within Kern County. The San Joaquin Valley portion is characterized by relatively low rainfall, averaging less than 10 inches per year. Average temperatures are relatively high, and total evaporation exceeds total precipitation. Summers are relatively cloudless, hot, and dry. Winter is generally mild, but an occasional freeze does occur and may cause substantial agricultural damage. Average length of the growing season is 265 days. The San Joaquin Valley region is within the southern end of the San Joaquin Valley Air Basin managed by the SJVAPCD. This district encompasses Fresno, Kings, Madera, Merced, San Joaquin, Stanislaus, and Tulare Counties, as well as the San Joaquin Valley portion of Kern County. Further, the San Joaquin Valley region is within the Tulare Lake Groundwater Basin, which includes the Kern River Hydrographic Unit and the Poso Hydrographic Unit. These are subject to Regional Water Quality Control Board oversight.

1.5.2 Surrounding Land Use

The Project Area is bordered on the west by San Luis Obispo County. The border between the two counties approximates the San Andreas Fault line. The Temblor Range forms a general barrier between the more industrial oil drilling operations on the Kern County side of the border verses the more rural and agricultural nature of neighboring San Luis Obispo County, with the exception of the Midway Sunset Oilfield, which crosses into neighboring San Luis Obispo County. The portion of the Midway Sunset Oilfield located within San Luis Obispo County is outside of the Project Area and is not subject to Kern County jurisdiction. Other oil and gas uses exist to the west of the Project Area; however, such activities are less intensive in nature and dispersed throughout a rural area.

To the south, the Project Area is bordered by the San Emigdo Mountains and the Tehachapi Mountains. The Project Area extends to the border of the Los Padres National Forest. The unincorporated community of Frazier Park is located in the uplands several miles south of the Project Area and west of Interstate 5.

To the north, the Project Area is bordered by Kings and Tulare Counties. The bordering areas of these two counties contain agricultural and oil and gas operations, as well as dispersed rural residences. The incorporated City of Delano is located on the northern border of Kern County, and adjacent land uses in Tulare County consist of large lot residential, agriculture, and industrial uses.

To the east, the Project Area is bordered by the foothills of surrounding mountain ranges, such as the Greenhorn Mountains and Tehachapi Mountains, as well as the Tejon Hills southeast of the incorporated City of Arvin. The Project Area also borders the Sequoia National Forest northeast of Bakersfield. Land uses along the border are generally rural in nature.

1.5.3 Project Objective

County Objectives

The County has defined the following objectives for the Project:

- Update the County's Zoning Ordinance to create a local permit for oil and gas activities so that County development standards and protective mitigation measures for the purpose of reducing or eliminating potential significant adverse environmental impacts, to the extent feasible, of future oil and gas activities, thereby ensuring that current County ordinances implement the Board of Supervisor's policies to protect the health, safety, and general welfare of communities, residents, and visitors.
- Encourage ongoing economic development by the oil and gas industry that creates quality, high-paying jobs and promotes capital investment in Kern County, which enables the County to invest in capital improvement projects and social programs, which benefit County residents, retail businesses, and capital industries, thus ensuring the County's fiscal stability.
- Continue Kern County's ongoing commitment to consult and cooperate with federal, state, regional, and local agencies by periodically reviewing adopted regulations to ensure the long-term viability of Kern County's resources.
- Continue to improve and streamline current energy regulations and increase County monitoring and involvement in state and federal energy legislation.
- Protect areas of important mineral, petroleum, and agricultural resource potential for future use by promoting sustainability and encouraging best management practices, which are mutually beneficial, through strategic short- and long-range planning.
- Ensure the protection of environmental resources by emphasizing the conservation of productive agricultural lands, the encouragement of planned urban growth, the promotion of clean air strategies to address existing air quality issues, and the promotion of long-term water conservation strategies that will ensure the quality and adequacy of surface and groundwater supplies for future growth of all of Kern County's industries.
- Contain new development within an area large enough to meet generous projections of foreseeable need but in locations that will not impair the economic strength derived from residential developments, agriculture, rangeland, or mineral resources, or diminish the other amenities that exist in Kern County.

Applicant Objectives

The Project Proponents have defined the following objectives for the Project:

- Create an effective regulatory and permitting process for oil and gas exploration and production that can be relied on by the County, as well as CalGEM and other responsible agencies.
- Achieve an efficient and streamlined environmental review and permitting process for all oil and gas operations covered by the proposed Project.
- Provide for economically feasible and environmentally responsible growth of the Kern County oil and gas industry.
- Develop industry-wide best practices, performance standards, and mitigation measures that ensure adequate protection of public health and safety and the environment.
- Increase oil and gas exploration and production in Kern County as a means of reducing California's dependence on foreign sources of energy.
- Increase oil and gas exploration and production in Kern County as a means of increasing employment opportunities and economic prosperity for Kern County's residents, businesses, and local government.

1.5.4 Project Characteristics

The proposed Project consists of a reconsideration of revisions to Title 19 of the Kern County Zoning Ordinance, Chapter 19.98 (Oil and Gas Production), and related sections of the Kern County Zoning Ordinance to include updated procedures, development standards and conditions for future oil and gas exploration, and development and production activities in unincorporated Kern County. In addition, the proposed Project includes the implementation of future oil and gas development activities expected to be undertaken pursuant to the amended ordinances.

Potential Future Oil and Gas Development Scenario

This section describes the potential future drilling and operational activities that could occur within the Project Area. For analytical purposes, as described in Chapter 2, Introduction, this SREIR assumes that 2,697 new producing wells per year—a relatively high level of new oil and gas production activity—would be projected to occur each year for the next 20 years. In practice, annual activity levels would likely be lower. There is no scheduled expiration date for a Zoning Ordinance, and the development standards and conditions specified in the Amended Zoning Ordinance would continue to apply unless and until the Zoning Ordinance is amended again. Further environmental review would not likely be needed for annual oil and gas activities that qualify for ministerial permits under the Conformity Review Process, as long as the annual projected activity level is not exceeded (e.g., no more than 2,697 new producing wells are drilled in a single calendar year) and the total projected activity level assumed to occur over the next 25 years is not exceeded (e.g., no more than 67,425 wells are drilled). However, at the point that either the annual project activity level or total projected activity level is exceeded, the County will need to consider whether the exceedance triggers further CEQA review in accordance with the criteria provided in CEQA (Public Resources Code) Section 21166 and CEQA Guidelines Section 15162 (e.g., due to new or substantially more severe significant environmental impacts than those considered in this SREIR). If the criteria for subsequent or supplemental CEQA review are met, further review would be required for continued reliance on the Conformity Review Process.

By amending the existing Zoning Ordinance to provide a new review process and site development standards, the proposed Project would provide for the continuation of existing oil and gas activity, which would have continued even if there were no Project, under current zoning. Therefore, the Potential Future Oil Development Scenario represents a continuation of existing oil and gas activities that, in conventional CEQA analysis, would be considered baseline conditions. Based on the current permitting in Kern County, the proposed Project's impacts on the existing environment would be beneficial by imposing new site development standards that incorporate more stringent, environmentally protective conditions than exist in the current Zoning Ordinance.

This SREIR takes an environmentally conservative approach to the impact analysis. The future environmental impacts associated with new oil and gas activities subject to approval by the County, utilizing the Oil and Gas Conformity Review process, are considered impacts of the proposed Project.

For example, air emissions associated with construction and operation of new wells or new wellbore re-entry activities (e.g., deepening, redrilling, workovers, reworking etc.), all subject to Oil and Gas Conformity Review under the amended Zoning Ordinance, are attributed to the proposed Project even though these emissions have occurred in the past and are likely to occur at the same levels in the future whether or not the Ordinance is amended. In addition, emissions from operation of ancillary facilities are attributed to the wells that receive Oil and Gas Conformity Review, on a per-well basis, even though a specific well may utilize existing ancillary facilities that have emitted in the past and are likely to continue emitting at the same levels in the future, whether or not the Ordinance is amended. Thus, all construction and operational emissions from, and associated with, wells that are subject to Oil and Gas Conformity Review are treated as new emissions of the proposed Project, regardless of whether Countywide emissions would change from historic baseline levels as a result of the amended Ordinance.

It should be emphasized that this approach differs from the conventional use of baselines in CEQA impact analysis. In the conventional analysis, the anticipated Countywide emissions after the proposed Project zoning amendments take effect would be estimated, and then the baseline emissions from existing oil and gas activities would be subtracted from post-Project emissions, in order to determine the extent of impacts attributable to the proposed Project. As a simplistic example, assuming that the average historic levels of oil and gas activities that generate air emissions do not change at all after the Zoning Ordinance amendments take effect, emissions would remain constant at the baseline, or perhaps even decline due to implementation of the performance standards that would be required by the amended ordinance. By definition, as long as the baseline standards were not exceeded, there would be no air quality impacts, even if thousands of new wells were drilled and began operating. By contrast, in the analytic approach taken in this SREIR, post-

Project emissions have been evaluated to identify impacts without subtracting baseline emissions. Thus, even if Countywide emissions remain constant at the baseline, the air quality impacts of the proposed Project would be determined by the total operational emissions of the new wells and ancillary activities approved under the amended Zoning Ordinance.

This analysis is more conservative than the conventional approach, by capturing ongoing environmental effects that otherwise would come under the baseline. Moreover, the conventional approach would not serve the objective of providing an environmental analysis that can be relied on by CalGEM and other responsible agencies in their own permitting and approval processes, as well as by Kern County.

The SREIR applies a similar approach to other categories of environmental impacts, although the details vary for some impact categories. For example, land disturbance, habitat loss, and biological resource impacts associated with construction and operation of wells (and related ancillary facilities) that receive Oil and Gas Conformity review would be considered impacts of the proposed Project. However, land disturbance, habitat loss, and other biological resource impacts associated with pre-existing wells, constructed under the current Zoning Ordinance, are part of the baseline and not impacts of the proposed Project. Unlike air emissions, which are emitted anew each day even if just due to continuing a pre-existing activity, land that has been disturbed remains in its disturbed state unless it is restored. As Communities for a Better Environment v. South Coast Air Quality Management District (2010) 48 Cal. 4th 310 emphasized, EIRs should not use a hypothetical baseline of conditions that do not actually exist; therefore, this SREIR does not assume a pristine, pre-oil and gas landscape where none currently exists. Similarly, the analysis of aesthetics/visual impacts takes into account existing permanent installed facilities and existing disturbed landscapes.

1.6 Environmental Impacts

Section 15128 of the CEQA Guidelines requires that an EIR contain a statement briefly indicating the reasons that various, possible, new significant effects of a project were determined not to be significant, and were therefore not discussed in detail in the EIR. The County has engaged the public to participate in the scoping of the environmental document.

The contents of this Draft SREIR were provided by the direction of the Court and modified based on a Notice of Preparation/Initial Study (NOP/IS) prepared in accordance with the CEQA Guidelines, as well as public and agency input that were received during the scoping process. The comments on the NOP/IS are found in Appendix A of this SREIR. Based on the findings of the NOP/IS and the results of scoping, a determination was made that this SREIR must contain an analysis of the five resource topic areas found deficient by the Court, as well as provide the reader with access to the 2015 FEIR analysis.

Impacts Not Further Considered in This SREIR

All relevant impacts are discussed in this Draft SREIR or included by reference from the 2015 FEIR. No resource areas were eliminated from discussion through the Initial Study for the 2015 FEIR, and all areas continue to be included in the record.

1.6.1 Impacts of the Proposed Project

This SREIR addresses the five topic areas (agricultural resources, air quality ($PM_{2.5}$ and multi-well health risk assessment), hydrology and water quality (groundwater supply and SGMA), noise, and utilities and service systems (groundwater supply and SGMA) identified by the Court as deficient. This section includes all impacts from both this SREIR and the 2015 FEIR as a comprehensive summary.

No Potential for Impacts to Occur

Potential environmental effects of the Project and corresponding mitigation measures are discussed in detail in Chapter 4, Environmental Setting, Impacts, and Mitigation Measures, of the 2015 FEIR (SREIR Volume 3) and Chapter 4 of this SREIR. The following effects were determined to have no potential for impacts to occur:

Agriculture and Forestry Resources

- Impact 4.2-3: Conflict with Existing Zoning For, Or Cause Rezoning Of, Forest Land or Timberland
- Impact 4.2-4: Result in the Loss of Forest Land or Conversion of Forest Land to Non-Forest Use
- Impact 4.2-6: Result in the Cancellation of an Open Space Contract Made Pursuant to the California Land Conservation Act of 1965 or Farmland Security Zone Contract for Any Parcel of 100 or More Acres

Hydrology and Water Quality

- Impact 4.9-7: Place Housing within a 100-year Flood Hazard Area as Mapped on a Federal Flood Hazard Boundary or Flood Insurance Rate Map or Other Flood Hazard Delineation Map
- Impact 4.9-10: In flood hazard, tsunami, seiche zones, risk release of pollutants due to project inundation

Population and Housing

- Impact 4.13-2 Displace Substantial Numbers of Existing Housing, Necessitating the Construction of Replacement Housing Elsewhere

- Impact 4.13-3 Displace Substantial Numbers of People, Necessitating the Construction of Replacement Housing Elsewhere

Less than Significant with No Required Mitigation Measures

Agriculture and Forestry Resources

- Impact 4.2-2: Conflict with Existing Zoning for Agricultural Use or a Williamson Act Contract
- Impact 4.2-7: Substantially decrease the productivity of livestock grazing activity within Kern County.

Hazards and Hazardous Materials

- Impact 4.8-6: Result in Safety Hazard for People Residing or Working in Project Area within Vicinity of a Private Airstrip.
- Impact 4.8-7: Impair Implementation of, or Physically Interfere with, an Adopted Emergency Response Plan or Emergency Evacuation Plan.

Land Use and Planning

- Impact 4.10-2: Conflict with Any Applicable Land Use Plan, Policy, or Regulation of an Agency with Jurisdiction Over the Project.
- Impact 4.10-3: Conflict with Any Applicable Habitat Conservation Plan or Natural Community Conservation Plan.
- Impact 4.10-4: Contribute to Cumulative Land Use Impacts.

Minerals

- Impact 4.11-1: Result in the Loss of Availability of a Known Mineral Resource that Would be of Value to the Region and the Residents of the State.
- Impact 4.11-2: Result in the Loss of Availability of a Locally Important Mineral Resource Recovery Site Delineated on a Local General Plan, Specific Plan, or Other Land Use Plan.
- Impact 4.11-3: Contribute to Cumulative Mineral Resources Impacts.

Noise

- Impact 4.12-2: Exposure of Persons to, or Generate, Excessive Ground-borne Vibration or Ground-borne Noise Levels.

Recreation

- Impact 4.15-1: Increase the Use of Existing Neighborhood and Regional Parks or Other Recreational Facilities Such That Substantial Physical Deterioration Would Occur or Be Accelerated.
- Impact 4.15-2: Include Recreational Facilities or Require Construction or Expansion of Recreational Facilities That Might Have an Adverse Physical Effect on the Environment
- Impact 4.15-3: Cumulative Impact on Recreational Facilities.

Less than Significant with Incorporation of Mitigation Measures

Potential environmental effects of the Project and mitigation measures are discussed in detail in Chapter 4, Environmental Settings, Impacts, and Mitigation Measures, of this SREIR. After full analysis, the following effects were determined to be less than significant with the incorporation of mitigation measures.

Air Quality

- Impact 4.3-1: Conflict With or Obstruct Implementation of the Applicable Air Quality Plan

Biological Resources

- Impact 4.4-1: Have a Substantial Adverse Effect, either Directly or through Habitat Modifications, on any Species Identified as a Candidate, Sensitive, or Special Status Species in Local or Regional Plans, Policies, or Regulations or by the California Department of Fish and Wildlife or the United States Fish and Wildlife Service
- Impact 4.4-2: Have a Substantial Adverse Effect on Any Riparian Habitat or Other Sensitive Natural Community Identified in Local or Regional Plans, Policies, Regulations, or by the California Department of Fish and Wildlife or the United States Fish and Wildlife Service
- Impact 4.4-3: Have a Substantial Adverse Effect on Federally Protected Wetlands as Defined by Section 404 of the Clean Water Act (Including, but Not Limited to, Marsh, Vernal Pool, Coastal, etc.) through Direct Removal, Filling, Hydrological Interruption, or Other Means
- Impact 4.4-4: Interfere Substantially with the Movement of any Native Resident or Migratory Fish or Wildlife Species, or with Established Native Resident or Migratory Wildlife Corridors, or Impede the Use of Native Wildlife Nursery Sites
- Impact 4.4-5: Conflict with Any Local Policies or Ordinances Protecting Biological Resources, Such as a Tree Preservation Policy or Ordinance

- Impact 4.4-6: Conflict with the Provisions of an Adopted Habitat Conservation Plan, Natural Community Conservation Plan, or Other Approved Local Regional, or State Habitat Conservation Plan

Cultural Resources

- Impact 4.5-1: Cause a substantial adverse change in the significance of a historical resource
- Impact 4.5-2: Cause a substantial adverse change in the significance of an archaeological resource
- Impact 4.5-3: Directly or indirectly destroy a unique paleontological resource or site
- Impact 4.5-4: Disturb any human remains, including those interred outside of formal cemeteries

Geology and Soils

- Impact 4.6-1: Expose People or Structures to Substantial Adverse Effects, Including the Risk of Loss, Injury, or Death Involving the Rupture of a Known Earthquake Fault
- Impact 4.6-2: Expose People or Structures to Substantial Adverse Effects, Including the Risk of Loss, Injury, or Death Involving Strong Seismic Ground Shaking
- Impact 4.6-3: Expose People or Structures to Substantial Adverse Effects, Including the Risk of Loss, Injury, or Death Involving Seismic-Related Ground Failure, Including Liquefaction
- Impact 4.6-4: Expose People or Structures to Substantial Adverse Effects, Including the Risk of Loss, Injury, or Death Involving Landslides
- Impact 4.6-5: Result in Substantial Soil Erosion or the Loss of Topsoil
- Impact 4.6-6: Be Located on a Geological Unit or Soil That is Unstable, or That Would Become Unstable as a Result of the Project, and Potentially Result in On- or Off-site Landslide, Lateral Spreading, Subsidence, Liquefaction, or Collapse
- Impact 4.6-7: Be Located on Expansive Soil, as Defined in Table 18-1-B of the Uniform Building Code (1994), Creating Substantial Risks to Life or Property
- Impact 4.6-8: Have Soils Incapable of Adequately Supporting the Use of Septic Tanks or Alternative Wastewater Disposal Systems Where Sewers Are Not Available for the Disposal of Wastewater
- Impact 4.6-9: Cumulative Impacts to Geologic and Soil Resources

Greenhouse Gas Emissions

- Impact 4.7-1: Generate Greenhouse Gas Emissions, Either Directly or Indirectly, That May Have a Significant Impact on the Environment

Hazards and Hazardous Materials

- Impact 4.8-1: Create a Significant Hazard to the Public or the Environment through the Routine Transport, Use, or Disposal of Hazardous Materials
- Impact 4.8-2: Create a Significant Hazard to the Public or the Environment through Reasonably Foreseeable Upset and Accident Conditions Involving the Release of Hazardous Materials into the Environment
- Impact 4.8-3: Emit Hazardous Emissions or Handle Hazardous or Acutely Hazardous Materials, Substances, or Waste within One-Quarter Mile of Existing or Proposed School.
- Impact 4.8-4: Create a Hazard to the Public or the Environment as a Result of Being a Site that is Included on a List of Hazardous Materials Sites Compiled Pursuant to Government Code Section 65962.5
- Impact 4.8-5: For a Project Located within the Adopted Airport Land Use Compatibility Plan, Result in a Safety Hazard for People Residing or Working in the Area
- Impact 4.8-8: Expose People or Structures to a Significant Risk of Loss, Injury, Or Death Involving Wildland Fires, Including Where Wildlands are Adjacent to Urbanized Areas or Where Residences are Intermixed with Wildlands
- Impact 4.8-9: Generate Vectors or Have a Component that Includes Agricultural Waste Exceeding Adopted Qualitative Thresholds
- Impact 4.8-10: Contribute to Cumulative Hazards and Hazardous Materials Impacts

Hydrology and Water Quality

- Impact 4.9-1: Violate any water quality standards or waste discharge requirements or otherwise substantially degrade surface or groundwater quality.
- Impact 4.9-3: Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or through the addition of impervious surfaces, in a manner which would: (i) result in a substantial erosion or siltation on- or offsite; (ii) substantially increase the rate of amount of surface runoff in a manner which would result in flooding on-or offsite; (iii) create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff; or (iv) impede or redirect flood flows.
- Impact 4.9-4: Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or through the addition of impervious surfaces, in a manner which would: (i) result in a substantial erosion or siltation on- or offsite; (ii) substantially increase the rate of amount of surface runoff in a manner which would result in flooding on-or offsite; (iii) create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff; or (iv) impede or redirect flood flows.

- Impact 4.9-5: Impact 4.9-5: Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or through the addition of impervious surfaces, in a manner which would: (i) result in a substantial erosion or siltation on- or offsite; (ii) substantially increase the rate of amount of surface runoff in a manner which would result in flooding on-or offsite; (iii) create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff; or (iv) impede or redirect flood flows.
- Impact 4.9-6: Violate any water quality standards or waste discharge requirements or otherwise substantially degrade surface or groundwater quality.
- Impact 4.9-8: Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or through the addition of impervious surfaces, in a manner which would: (i) result in a substantial erosion or siltation on- or offsite; (ii) substantially increase the rate of amount of surface runoff in a manner which would result in flooding on- or offsite; (iii) create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff; or (iv) impede or redirect flood flows.
- Impact 4.9-9: Expose People or Structures to a Significant Risk of Loss, Injury, or Death Involving Flooding, Including Flooding as a Result of the Failure of a Levee or Dam

Land Use and Planning

- Impact 4.10-1: Physically Divide an Established Community

Public Services

- Impact 4.14-1: Result in Substantial Adverse Physical Impacts Associated with the Provision of New or Physically Altered Government Facilities, Need for New or Physically Altered Government Facilities, the Construction of Which Could Cause Significant Environmental Impacts, in Order to Maintain Acceptable Service Ratios, Response Times, or Other Performance Objectives for Any of the Public Services, which Include: Fire Protection, Police Protection, Schools, Parks, and Other Public Facilities
- Impact 4.14-2: Contribute to Cumulative Public Service Impacts

Transportation and Traffic

- Impact 4.16-1: Conflict with an Applicable Plan, Ordinance, or Policy Establishing Measures of Effectiveness for the Performance of the Circulation System, Including but Not Limited to Intersections, Streets, Highways and Freeways, Pedestrian and Bicycle Paths, and Mass Transit
- Impact 4.16-2: Conflict with an Applicable Congestion Management Program, including, but not limited to Level of Service Standards and Travel Demand Measures, or Other

Standards Established by the County Congestion Management Agency or Adopted County Threshold for Designated Roads or Highways

- Impact 4.16-3: Result in a Change in Air Traffic Patterns, including Either An Increase in Traffic Levels or a Change in Location that Results in Substantial Safety Risks
- Impact 4.16-4: Substantially Increase Hazards due to a Design Feature (e.g., Sharp Curves or Dangerous Intersections) or Incompatible Uses
- Impact 4.16-5: Result in Inadequate Emergency Access
- Impact 4.16-6: Conflict with Adopted Policies, Plans, or Programs regarding Public Transit, Bicycle, or Pedestrian Facilities, or Otherwise Decrease the Performance or Safety of Such Facilities
- Impact 4.16-7: Cumulative Impacts on Transportation and Traffic

Utilities and Service Systems

- Impact 4.17-1: Exceed Wastewater Treatment Requirements of the Applicable Regional Water Quality Control Board
- Impact 4.17-2: Require or Result in the Construction of New Water or Wastewater Treatment Facilities or Expansion of Existing Facilities, the Construction of which could cause Significant Environmental Effects
- Impact 4.17-3: Require or Result in the Construction of New Stormwater Drainage Facilities or Expansion of Existing Facilities, the Construction of which could cause Significant Environmental Effects
- Impact 4.17-5: Result in a Determination by the Wastewater Treatment Provider that Serves or May Serve the Project that it has Adequate Capacity to Serve the Project's Projected Demand in Addition to the Provider's Existing Commitments
- Impact 4.17-6: Generate solid waste in excess of state or local standards, or in excess of the capacity of local infrastructure, or otherwise impair the attainment of solid waste reduction goals
- Impact 4.17-7: Comply with federal, State, and local management and reduction statutes and regulations related to solid waste

Unavoidable Significant Adverse Impacts

Section 15126.2(b) of the CEQA Guidelines requires that an EIR describe any significant impacts, including those that can be mitigated but not reduced to less-than-significant levels. Potential environmental effects of the proposed Project and proposed mitigation measures are discussed in detail in Chapter 4 of this EIR. The following environmental impacts were determined to be significant and unavoidable (Table 1-3).

Table 1-3: Summary of Unavoidable Significant Adverse Impacts of the Project

Resources	Project Impacts	Cumulative Impacts
Aesthetics and Visual Resources	Although implementation of mitigation measures would reduce the adverse visual changes experienced at individual key observation point locations, there are no mitigation measures that would preserve the existing character and quality of the Project Area and its surroundings. Project-related oil and gas activities would continue to produce visible changes to the existing environment and the resultant visual impact is considered **significant and unavoidable**. The Project has the potential to create a new source of substantial light or glare that would adversely affect day or nighttime views in the area. After implementation of MM 4.1-6, this impact would remain **significant and unavoidable.**	The oil and gas industry has a visible presence on the landscape of the San Joaquin Valley Floor, and the Project in combination with the implementation of other reasonably foreseeable oil and gas projects will continue to result in adverse visible changes within Kern County. Therefore, the Project's cumulative contribution after implementation of the recommended mitigation measures would remain cumulatively **significant and unavoidable** as a result of these changes in visual character and quality.
Air Quality	The construction and operational activities of oil and gas activities that would be authorized under the Project would result in an increase of criteria pollutants (oxides of nitrogen [NO_X], volatile organic compounds [VOCs], carbon monoxide [CO], particulate matter less than 10 microns and less than 2.5 microns in diameter [$PM_{10]}$ and $PM_{2.5}$, respectively]) in excess of the recommended criteria pollutant significance thresholds adopted by the San Joaquin Valley Air Pollution Control District (SJVAPCD) Board. Therefore, the proposed Project would result in a cumulatively considerable net increase of criteria pollutants (NO_X, PM_{10}, $PM_{2.5}$, CO, and SO_2) emissions for which the San Joaquin Valley Air Basin (SJVAB) is in non-attainment. After implementation of MM 4.3-1 through MM 4.3-4, and MM 4.3-8, impacts would remain **significant and unavoidable**. The Project would expose sensitive receptors to substantial pollutant concentrations and poses health risks With implementation of MM 4.3-5, MM 4.3-6, and MM 4.3-9, impacts would remain **significant and unavoidable**. The Project would continue to generate odors. With	The construction and operational activities of oil and gas activities that would be authorized under the Project would result in an increase of criteria pollutants (oxides of nitrogen [NO_X], volatile organic compounds [VOCs,], carbon monoxide [CO], particulate matter less than 10 microns and less than 2.5 microns in diameter [PM_{10}, and $PM_{2.5}$, respectively]) in excess of the recommended criteria pollutant significance threshold adopted by the SJVAPCD Board. Emission sources in Kern County contribute between 11% and 21% of criteria pollutant emissions in the San Joaquin Valley Air Basin. The Project would contribute between 2% and 14% of these pollutants in the San Joaquin Valley Air Basin or between 19% and 97% of Kern County's contribution. This analysis indicates that most sulfur dioxide (SO_2) emissions in Kern County would originate from oil and gas activities. Therefore, the proposed Project would have a **cumulatively considerable** contribution of criteria pollutant (NO_X, PM_{10}, $PM_{2.5}$, CO, and SO_2) emissions to the Kern

Table 1-3: Summary of Unavoidable Significant Adverse Impacts of the Project

Resources	Project Impacts	Cumulative Impacts
	implementation of MM 4.3-7, impacts would remain **significant and unavoidable**.	County portion of the SJVAB, including health risks for vulnerable populations. After implementation of MM 4.3-8, impacts would remain **significant and unavoidable**.
Agricultural Resources	There are no feasible mitigation measures to reduce the Project's potential to convert prime farmland, unique farmland, or farmland of statewide importance to non-agricultural use and this impact would be **significant and unavoidable**. The Project has the potential to involve other changes in the existing environment which, because of their location or nature, could result in the conversion of farmland to non-agricultural use or conversion of forest land to non-forest use. With implementation of MM 4.2-1, this impact would remain **significant and unavoidable**.	The geographic scope for cumulative impacts to agricultural and forest resources encompasses the whole of Kern County. The oil and gas exploration and production activities that would be authorized through implementation of the proposed Project, along with projected population growth, could result in **significant and unavoidable** cumulative impacts on farmland conversion.
Biological Resources	None.	Future oil and gas exploration and production activities related to the proposed Zoning Ordinance amendment could contribute to a significant cumulative impact on Project Area biological resources because future use and development of federal, state, and incorporated urban lands are not within the County's jurisdiction or control. Future land uses and development could affect biological resources in each of these jurisdictions and would be undertaken as independent actions with associated impacts, avoidance and minimization requirements, and mitigation, if required, under applicable federal, state, regional and local agency law. Impacts would remain **significant and unavoidable** with mitigation.
Cultural Resources	None.	The geographic scope for cumulative impacts to cultural and paleontological resources includes the area within a one-mile radius from the Project Area. Cumulative impacts could result when paleontological, historical, and archaeological resources or human

Table 1-3: Summary of Unavoidable Significant Adverse Impacts of the Project

Resources	Project Impacts	Cumulative Impacts
		remains cannot be avoided by future projects. For paleontological and archaeological resources, it is important to recover a scientifically significant sample so the information can be preserved. For historic buildings and structures, detailed recordings, including measured drawings and photographs, can preserve the information. For human remains, reburial in a location not slated for future development can protect those remains from future disturbance. There could be **significant cumulative impacts** to paleontological, historical, and archaeological resources or human remains as a result of the oil and gas exploration and production activities that would be authorized under the Project. Implementation of best professional practices would reduce many impacts to a less than significant level. However, buried archaeological and paleontological resources could be damaged or destroyed. Direct mitigation using the measures above would reduce most of these impacts to a **less than significant level**.
Greenhouse Gases	The Project has the potential to conflict with an applicable plan, policy or regulation adopted for the purpose of reducing the emissions of greenhouse gases. With the implementation of MM 4.7-5, the impact would remain **significant and unavoidable.**	The geographic scope for cumulative impacts for GHGs includes the area within 6 miles of the external Project Area boundary, and areas (e.g., incorporated cities) within the Project Area. Climate change impacts are inherently global and cumulative, and not Project specific. While implementation of MM 4.7-1 through MM 4.7-3 and the 2014 Regional Transportation Plan mitigation measures would encourage reduction in GHG emissions at a regional level, they do not provide a mechanism that guarantees GHG emission reductions on a cumulative basis. The Project's cumulative

Table 1-3: Summary of Unavoidable Significant Adverse Impacts of the Project

Resources	Project Impacts	Cumulative Impacts
		contribution after implementation of the recommended mitigation measures would remain **cumulatively significant and unavoidable** as a result of the GHG emissions associated with the Project.
Hydrology and Water Quality	The Project has the potential to substantially decrease groundwater supplies or interfere substantially with groundwater recharge such that the Project may impede sustainable groundwater management of the basin or conflict with or obstruct implementation of a water quality control plan or sustainable groundwater management plan. <u>*MM 4.17-3 and MM 4.17-4 will ensure that future activities permitted under the Project will provide regional groundwater management agencies with sufficient information, including groundwater use from metered wells, to integrate Project-related groundwater use with the development of a comprehensive sustainable groundwater management solution for basins and subbasin in the Project Area.*</u> As discussed in Section 4.9, Hydrology and Water Quality, there is no feasible mitigation to reduce this impact, which would be **significant and unavoidable**.	The Project's increased oil and gas use of domestic and irrigation quality water, although relatively small in comparison to other uses, is a significant impact and contributes to a cumulatively significant impact to sustainable groundwater management and sustainable groundwater management plan implementation. <u>*MM 4.17-5 provides funds that will mitigate for the Project's fair share of cumulative impacts to disadvantaged communities that are insufficiently considered in the existing SGMA process.*</u> As discussed in Section 4.9, Hydrology and Water Quality, there is no feasible mitigation to reduce this impact, which would be **significant and unavoidable**.
Noise	The Project could generate a substantial temporary or permanent increase in ambient noise levels in the vicinity of the Project. Although the construction and operational noise would be mitigated to the level of standards established in the local general plan due to oil and gas activities authorized under the Project, the sensitivity of sensitive receptors to noise in excess of the their ambient experience is considered significant. With the implementation of MM 4.12-1 and MM 4.12-2, impacts would remain **significant and unavoidable**. The Project, located within the vicinity of a private or public airstrip, could expose people residing or working in the Project Area to excessive noise levels. With the implementation	The Project, in combination with other existing or reasonably foreseeable projects, could result in cumulative impacts on noise receptors due to noise levels in excess of the County's General Plan standard. Further, the sensitivity of sensitive receptors to noise in excess of their ambient experience is considered significant. With the implementation of MM 4.12-1 and MM 4.12-2, impacts would remain **significant and unavoidable**.

Table 1-3: Summary of Unavoidable Significant Adverse Impacts of the Project

Resources	Project Impacts	Cumulative Impacts
	of MM 4.12-1 and MM 4.12-2, impacts would remain **significant and unavoidable**.	
Utilities and Service Systems	The Project would have the potential to have insufficient groundwater supplies to serve both the Project and reasonably foreseeable future development during normal, dry, and multiple dry years. The allocation of water supplies and water demands, the complex laws affecting water rights, the many water districts that have legal jurisdiction over one or more sources of water in the Project Area, the requirements of the Sustainable Groundwater Management Act, the varied technical feasibility of treating produced water, and the produced water reuse opportunities all present complex variables that fall outside the scope of the County's jurisdiction or control under CEQA. <u>*MM 4.17-3 and MM 4.17-4 will ensure that future activities permitted under the Project will provide regional groundwater management agencies with sufficient information, including groundwater use from metered wells, to integrate Project-related groundwater use with the development of a comprehensive sustainable groundwater management solution for basins and subbasin in the Project Area.*</u> As discussed in Section 4.17, Utilities and Service Systems, there is no feasible mitigation to reduce this impact, which would be **significant and unavoidable**.	The geographic scope for cumulative impacts to utilities and service systems includes the area within 6 miles of the external Project Area. Cumulative impacts would be **significant and unavoidable with respect to groundwater supply**. <u>*MM 4.17-5 provides funds that will mitigate for the Project's fair share of cumulative impacts to disadvantaged communities that are insufficiently considered in the existing SGMA process.*</u> For other public utilities, including municipal wastewater treatment, stormwater management, or landfills with mitigation, impacts would be **less than significant** with mitigation measures.

1.6.2 Significant Cumulative Impacts

According to Section 15355 of the CEQA Guidelines, the term cumulative impacts "refers to two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts." Individual effects that may contribute to a cumulative impact may be from a single project or a number of separate projects. Individually, the impacts of a project may be relatively minor, but when considered along with impacts of other closely related or nearby projects, including newly proposed projects, the effects could be cumulatively considerable.

This SREIR has considered the potential cumulative effects of the proposed Project. Impacts for the following issue areas have been found to be cumulatively considerable:

- Aesthetics
- Agriculture and Forest Resources
- Air Quality
- Greenhouse Gases
- Biology
- Cultural
- Hydrology (related to Groundwater Supply)
- Noise
- Utilities (related to water supply)

Each of these significant cumulative impacts is discussed in the applicable section of Chapter 4, Environmental Settings, Impacts, and Mitigation Measures, of the 2015 FEIR, 2018 SEIR, and this SREIR.

1.6.3 Growth Inducement

The KCGP and Metropolitan Bakersfield General Plan (MBGP) recognize that certain forms of growth are beneficial, both economically and socially. Section 15126.2(d) of the CEQA Guidelines provides the following guidance on growth-inducing impacts: a project is identified as growth inducing if it "could foster economic or population growth, or the construction of additional housing, either directly or indirectly, in the surrounding environment." The Project's potential impacts related to growth inducement were assessed in the 2015 FEIR (SREIR Volume 3).

1.6.4 Irreversible Impacts

Section 15126.2(c) of the CEQA Guidelines defines an irreversible impact as an impact that uses nonrenewable resources during the initial and continued phases of a project. Irreversible impacts can also result from damage caused by environmental accidents associated with a project. Irretrievable commitments of resources should be evaluated to ensure that such consumption is justified. Oil and gas development and operational activities associated with the implementation of the Amendment to Chapter 19.98 (Oil and Gas Production) and related ordinance amendments to the Kern County Zoning Ordinance would commit nonrenewable resources during construction and operation activities. During these activities, oil, gas, and other nonrenewable resources would be consumed. Therefore, an irreversible commitment of nonrenewable resources would occur as a result of the ongoing production of oil and gas in the Project Area as is authorized by the current and proposed Amended Zoning Ordinance. However, assuming that those commitments occur in accordance with the adopted goals, policies, and implementation measures of the KCGP and

MBGP, as a matter of public policy, those commitments have been determined to be acceptable. The KCGP and MBGP ensure that any irreversible environmental changes associated with those commitments will be minimized.

1.7 Alternatives to the Proposed Project

Section 15126.6 of the CEQA Guidelines states that an EIR must address "a range of reasonable alternatives to the Project, which would feasibly attain most of the basic objectives of the Project but would avoid or substantially lessen any of the significant effects of the Project, and evaluate the comparative merits of the alternatives." Based on the significant and unavoidable impacts related to aesthetics, agricultural resources, air quality, greenhouse gases, biology, cultural resources, hydrology, and utilities, along with the proposed Project objectives, several alternatives were considered, as summarized below and discussed in detail in Chapter 6, Alternatives.

1.7.1 Alternatives Eliminated from Further Consideration

Kern County considered several alternatives to reduce the Project's significant and unavoidable impacts. Per CEQA, the lead agency may make an initial determination as to which alternatives are feasible and warrant further consideration, and which are infeasible. The following alternatives were initially considered but were eliminated from further consideration in this EIR because they do not meet Project objectives and/or were infeasible.

- **Drilling Ban on Agriculturally Productive Lands Alternative:**
  - *Example:* The Ordinance could require the conformity review process within a smaller area, which would not include land that is currently being used to produce agricultural products.
  - This alternative would accomplish some County Project objectives by providing environmental restrictions to protect agricultural land. It would accomplish Oil Applicant objectives of continued, projected development. However, it may not reduce environmental impacts of the oil development as much as the proposed Project and with the implementation of the SGMA agriculturally productive land definitions are in transition.
- **Drilling Ban on All Lands Alternative:**
  - *Example:* The ordinance would ban all drilling.
  - *Rejected as Infeasible*: This alternative is legally infeasible because of the property rights of mineral holder exposing the County to a regulatory takings challenge. Such an ordinance would infringe on operators' rights to develop mineral resources. The economic stability of the provision of public services through property tax revenues supplied by the oil and gas industry have no identifiable replacement.
- **Larger Project Area Alternative:**
  - *Example***:** The Ordinance would apply to a larger area than in the proposed Project.

  - *Rejected because Will Not Reduce Significant Impacts:* Analysis of this alternative for Kern County cannot occur as the Project boundary as currently defined is where oil occurs and drilling is expected. If no drilling is expected outside this area, no purpose is served by expanding the Project scope.

- **More Wells within Project Footprint Alternative:**
  - *Example*: The current proposal limits the number of annual permits based on the environmental impacts on the SJVAPCD attainment plans. CEQA does not require a speculative alternative that cannot be achieved.
  - *Rejected because Will Not Reduce Significant Impacts:* A larger number of wells would not reduce significant impacts.

- **Fewer Wells within the Project Footprint Alternative, with a 2,500-Foot Setback from Sensitive Receptors**
  - *Example:* The Ordinance would limit/constrain the number of wells drilled annually over the life of the Project and include a 2,500-foot setback from sensitive receptors.
  - *Feasibility:* This alternative was eliminated as legally infeasible because it may illegally restrict someone's rights to develop their resources

- **Offsite Alternative:**
  - *Feasibility:* This is not a feasible alternative because the development facilities need to be in proximity to the resources (Guidelines 15126.6(f)(2)(B)).

1.7.2 Alternatives to the Project

Alternatives that would avoid or substantially lessen any of the significant effects of the Project and that would feasibly attain most of the basic Project objectives are discussed below. Each alternative is discussed and summarized with respect to its relationship to the Project objectives and fully discussed in Chapter 6.0, Alternatives of this SREIR.

Alternative 1: No Project

As required by CEQA Guideline §15126.6, this chapter describes and analyzes a "no project" alternative for the purpose of comparing the impacts of approving the Project with the impacts of not approving the Project. Alternative 1, the No Project Alternative, thus assumes that the Project's proposed amendment to Title 19 of the Zoning Ordinance will not be approved. Accordingly, Alternative 1 assumes that Chapter 19.98 of the Zoning Ordinance will not be amended to establish updated development standards and conditions to address environmental impacts of pre-drilling exploration, well drilling, and the operation of wells and other oil and gas production-related equipment and facilities, including exploration, production, completion, stimulation, reworking, injection, monitoring, and plugging and abandonment. Moreover, Alternative 1 assumes that Chapter 19.98 of the Zoning Ordinance will not be amended to establish a new Oil and Gas Conformity Review ministerial permit procedure for County approval of future well drilling and operations to ensure compliance with the updated development standards and conditions and provide for ongoing tracking and compliance monitoring. Finally, under Alternative 1, the Zoning Ordinance would not be updated to incorporate the Project's relevant proposed development standards into the County's Dark Skies Ordinance or the Zoning Ordinance provisions governing Hillside Development as well as the Floodplain Primary (FPP) and the Petroleum Extraction (PE) Combining District.

Alternative 1 assumes that oil and gas development and production activities will continue in the Project Area in accordance with the existing Zoning Ordinance. As discussed in Chapter 3, Project Description, Section 19.98.020 of the existing Zoning Ordinance currently authorizes "unrestricted drilling," with no County permit required, in County lands zoned for Exclusive Agriculture (A), Limited Agriculture (A-1), Medium Industrial (M-2), Heavy Industrial (M-3), and Natural Resource (NR), subject to compliance with specified conditions and standards which augment those of CalGEM, the SJVAPCD, and applicable fire and safety ordinances and regulations of the County. Thus, in these zoning districts, no review or permit would be required under the No Project Alternative for the drilling of any well intended for the exploration for, or development or production of, oil, gas, and other hydrocarbon substances, or for any related accessory equipment, structure, or facility used as part of the oil and gas production process. However, per the existing Zoning Ordinance, under Alternative 1, drilling would continue to be prohibited within, at minimum, 100 feet of any existing residence without the written consent of the owner thereof.

Under Alternative 1, oil or gas exploration or production would continue to be allowed within the FPP, subject to the Special Review Procedures and Development Standards set forth in Zoning Ordinance Section 19.50.130. Moreover, oil or gas exploration or production would continue to be permitted within a Special Planning District, provided it is consistent with the County General plan land use designation applicable to the subject property and does not create a conflict with the public health, safety, and welfare.

In addition, under Alternative 1, drilling by "ministerial permit" will continue in several zoning districts pursuant to Zoning Ordinance Section 19.98.030. A "ministerial" permit requires an application and review process, but the County does not impose site-specific conditions in such permits and the Applicant is entitled to receive the permit once it demonstrates that relevant standards are met. Under Alternative 1, ministerial permits will continue to be required in the Light Industrial (M-1) and Recreation-Forestry (RF) Districts, subject to specified development standards, which will also continue to apply in Drilling Island Zone Districts, and PE Combining District.

Under Alternative 1, a CUP will continue to be required for oil or gas exploration or production in all residential districts, including the Estate District, as well as in the Low, Medium, and High-Density Residential Districts. A CUP will also continue to be required in commercial districts, including the Commercial Office District, Neighborhood Commercial District, General Commercial District, and Highway Commercial District, as well as in the Platted Lands District. Finally, under Alternative 1, oil and gas exploration or production will continue to be prohibited in Mobile Home Park District (Section 19.26.040) and in the Open Space District zoning districts (Section 19.44.040).

Alternative 2: Conditional Use Permit

Under Alternative 2, the CUP Alternative, all new oil and gas exploration, development, and production activities would be permitted in the Project Area only upon the County's issuance of a CUP that authorizes such activities. Under Alternative 2, Chapter 19.98 of the Zoning Ordinance would be amended to eliminate Sections 19.98.020 (Unrestricted Drilling) and 19.98.030 (Drilling By Ministerial Permit), and amend Section 19.98.040 to require a conditional use permit for new oil and gas development and production activities in the following zoning districts: Exclusive Agriculture (A); Limited Agriculture (A-1); Medium Industrial (M-2); Heavy Industrial (M-3); Natural Resource (NR); Light Industrial (M-1); Recreation-Forestry (RF); Estate District (E); Low, Medium, and High-Density (R-1, R-2, and R-3); Commercial Office (CO); Neighborhood Commercial (C-1); General Commercial (C-2); Highway Commercial (CH); Platted Lands (PL); FPP; and Special Planning (SP). Conforming amendments would also be made to the Zoning Ordinance chapters applicable to each of these zoning districts to clarify that oil and gas exploration, development, and production activities are conditionally permitted uses within such districts. In effect, Alternative 2 would amend the Zoning Ordinance to eliminate all unrestricted, and ministerial approval of, oil and gas exploration, development, and production activities. Under Alternative 2, such activities would only be permitted upon issuance of a CUP in all zoning districts, except the Mobile Home Park District (MP) and the Open Space District (OS), where new oil and gas development and production activities would continue to be prohibited.

Like the Project, Alternative 2 would amend Zoning Ordinance Chapter 19.98 to establish updated development standards and conditions to address environmental impacts of pre-drilling exploration, well drilling and the operation of wells and other oil and gas production-related equipment and facilities, including exploration, production, completion, stimulation, reworking, injection, monitoring, and plugging and abandonment. Unlike the Project, however, Alternative 2 would not amend the Zoning Ordinance to establish a new Oil and Gas Conformity Review procedure to ensure compliance with all of the updated development standards and conditions and provide for ongoing tracking and compliance monitoring. Instead, under Alternative 2, implementation of the updated development standards and conditions would occur on a case-by-case basis as deemed necessary through the standard CUP approval and compliance monitoring processes.

Alternative 3: Reduced Ground Disturbance Alternative

Alternative 3, the Reduced Ground Disturbance Alternative, is identical to the Project, except that it would prohibit all new well drilling activities outside existing CalGEM-designated "Administrative Boundary" areas and would require subsurface oil and gas to be extracted from surface equipment located within such Administrative Boundary areas. This alternative would also limit the disturbance footprint on existing agricultural lands to requiring clustering of new wells in locations immediately adjacent to existing oil and gas equipment. As discussed in Chapter 3, Project Description, the vast majority of future oil and gas production in Kern County will occur in and adjacent to Administrative Boundary areas. Accordingly, this alternative assumes that subsurface oil and gas resources located outside of existing Administrative Boundary areas could still be accessed from inside existing Administrative Boundary areas through use of directional and horizontal drilling techniques. Thus, Alternative 3's restrictions on oil and gas exploration and development are assumed to be legally feasible.

Like the Project, Alternative 3 would amend sections of the Zoning Ordinance relating to oil and gas drilling, including Chapter 19.98 (Oil and Gas Production), to establish updated development standards and conditions to address environmental impacts of pre-drilling exploration, well drilling and the operation of wells and other oil and gas production-related equipment and facilities, including exploration, production, completion, stimulation, reworking, injection, monitoring, and plugging and abandonment. Like the Project, Alternative 3 would amend Zoning Ordinance Chapter 19.98 to establish a new Oil and Gas Conformity Review ministerial permit procedure for County approval of future well drilling and operations within the Project Area to ensure compliance with the updated development standards and conditions and provide for ongoing tracking and compliance monitoring. Unlike the Project, however, no new ground disturbance from well drilling activities would be allowed outside existing Administrative Boundary areas.

Alternative 4: No Hydraulic Fracturing Alternative

Pursuant to its police power, the County has broad discretion to regulate oil and gas exploration and production activities within its jurisdiction. However, a local government's legal authority to regulate every step in the hydraulic fracturing process is the subject of legal disputes currently pending in certain California courts. Assuming the County has sufficient legal authority to regulate subsurface oil and gas exploration and development activities as contemplated by this alternative, Alternative 4, the No Hydraulic Fracturing Alternative, would implement the Project as proposed, except that it would amend Zoning Ordinance Chapter 19.98 to ban all hydraulic fracturing activities, a form of well stimulation, within the Project Area. In all other respects, the Alternative 4 is the same as the Project.

Alternative 4 would only prohibit hydraulic fracturing in the Project Area, but it would not prohibit acid fracturing or acid matrix well stimulation techniques. Were Alternative 4 approved, however, it is unlikely that the hydraulic fracturing ban would cause an increase in acid fracturing or acid matrix well stimulation in the Project Area. Hydraulic fracturing is a viable well stimulation treatment in diatomite subsurface formations, as explained in Section 4.9, Hydrology and Water Quality. In contrast, acid fracturing and acid matrix stimulation techniques are only viable in carbonate reservoir rocks and siliciclastic reservoir formations, respectively. Thus, acid fracturing and acid matrix techniques do not serve as viable substitutes for hydraulic fracturing. Moreover, as explained in Section 4.9, there are no carbonate reservoir rocks in Kern County oil and gas fields that would be subject to acid fracturing techniques, in any case. A ban on hydraulic fracturing may, however, cause an increased use of enhanced oil recovery (EOR) techniques in the Project Area.

Alternative 5: Low-Emission Enhanced Oil Recovery Technology Alternative

Alternative 5, the Low-Emission EOR Alternative, is identical to the proposed Project, except that the updated development standards and conditions required by the Project's proposed Zoning Ordinance amendment would be expanded to require oil and gas well permit applicants to implement low-emission EOR technology as a condition of permit approval for new and replacement steam generators, and to replace existing steam generators constructed prior to 1990 within five years of enactment of the amended Zoning Ordinance. As explained in Chapter 3, Project Description, EOR is a production technique used to increase the mobility of oil, most commonly through steam injection techniques that reduce the viscosity of the hydrocarbons and allow produced fluids to flow. There are four major types of EOR operations: waterflood; thermal (i.e., steamflood, cyclic steam and in situ combustion); carbon dioxide or other gas (miscible and immiscible); and chemical/polymer flooding (i.e., alkaline flooding or micellar-polymer flooding). With thermal EOR, steam is injected into a well, which necessitates the installation of steam generators at the well. Steam generators are large heaters that generate steam, usually from produced groundwater. Under Alternative 5, all new and replacement steam generators for thermal EOR activities would be required to implement low-emission steam generation technology, such as the ClearSign Duplex Tile combustion technology or the equivalent. In all other respects, Alternative 5 would be identical to the Project.

Alternative 6: Recycled Water Alternative

Under Alternative 6, the Recycled Water Alternative, the Applicants would be required to treat an amount produced water that is currently being disposed of via underground injection wells which is equivalent to the amount of municipal and industrial water used in Applicant's operations. The produced water reuse goal is 30,000 acre-feet (AF) per year, which would offset more than the current use of imported water and groundwater from non-oil-bearing zones by the oil and gas industry. Such produced water would be required to be treated, recycled, and put to an alternate use such as agricultural irrigation to the extent feasible. As explained in Section 4.9, Hydrology and Water Quality, oil-bearing formations in the Project Area include a mixture of usually saline or other poor-quality groundwater and hydrocarbons. Production wells extract a mixture of water and hydrocarbons that is separated in surface facilities, typically a series of tanks or "tank batteries," where lighter oil and gas compounds are isolated and skimmed from the heavier water. Residual water generated by the hydrocarbon separation process is generally referred to as "produced water" in the context of oil and gas exploration and production. Under current practices, much of this produced water is used in future oil and gas recovery operations (e.g., steam and water flooding) and for oil and gas maintenance activities, and the remainder is disposed of primarily through underground injection wells. In some portions of the Project Area, produced water is also treated and reused for agricultural irrigation purposes, as explained in Section 4.9, Hydrology and Water Quality.

Produced water is often treated to remove salts and other constituents for reuse in the oil and gas exploration and production process. As explained in Section 4.9, Hydrology and Water Quality, over 234,000 AF of produced water was extracted in 2010, and by 2035 the annual amount of produced water could increase to more than 324,000 AF. As explained in Section 4.17, Utilities and Service Systems, about 38% of the total volume of produced water in 2012, or 88,812 AF, was reused for water and steam injections, pressure maintenance, well pulling, coil tubing activities, dust control, and surface facility construction. Produced water demand for oil and gas reuse is expected to rise to 122,234 AF by 2035. In addition, about 32,771 AF per year of relatively high-quality produced water from oilfields located along the base of the Sierra Nevada in the Eastern

Subarea is provided to the Cawelo Water District for agricultural reuse. Produced water reuse for irrigation requires additional filtration and treatment to meet applicable water quality standards.

Under Alternative 6, applicants would be required to fund treatment and conveyance facilities for produced water for local reuse (such as agricultural irrigation). For purposes of analysis in this SREIR, this alternative assumes (1) that water treatment facilities would be located in Tier 1 areas more than 1,000 feet away from the nearest sensitive receptor; (2) that treatment facilities would be subject to New Source Review permit requirements (where applicable), including use of best available control technology to minimize air emissions; (3) that remaining criteria and greenhouse gas emissions would be fully offset; and (4) and that waste products (including residuals from treated produced water) would be disposed of in accordance with applicable law. In all other respects, Alternative 6, the Recycled Water Alternative, is identical to the proposed Project.

Alternative 7 – 2,500-Foot Setback Alternative

Local jurisdictions in other states, including Colorado, New Mexico, Oklahoma, Pennsylvania, Texas, and Wyoming have established minimum setback distances between oil and gas facilities and sensitive land uses such as residences, most ranging between 500 and 1,500 feet (Minner 2015). As noted in a detailed analysis of setback distances in the Dallas-Fort Worth, Texas area, "there is no uniform setback distance, distances have increased over time, and, rather than technically-based, setbacks are political compromises" (Fry 2013). Moreover, to the extent that some setbacks in other areas of the country may be based on scientific analysis, drilling practices and topographic, meteorological and geological conditions differ from those in Kern County. As discussed in Section 4.2, Agricultural Resources, formations in Kern County are largely dominated by complex structural geometry where faulting creates discontinuous producible reservoirs. By contrast, in other regions of the United States, geological formations are more homogeneous and producible reservoirs are laid out in flat and long intervals suitable for access by horizontal drilling, with accompanying increased emissions and other impacts.

Other local jurisdictions within California have also adopted setbacks between oil and gas sites and sensitive land uses, most commonly set at 300 feet; for example, by Los Angeles County and the Cities of Arvin, Huntington Beach and Signal Hill. As in other states, local setback distances in California are often the result of political compromises rather than scientific analysis. The Ventura County 2040 General Plan, adopted in September 2020, established a 1,500-foot setback between new oil wells and residences and a 2,500-foot setback from schools (Ventura County 2020). Currently, Ventura County's General Plan 2040 is being challenged in court. No other local jurisdiction in the United States has established a 2,500-foot setback for oil and gas sites.

To protect against health risks from impacts to air quality, MM 4.3-5 requires that the Site Plan for a proposed activity include a Site Vicinity Figure showing the location of any sensitive receptor(s) located within 4,000 feet (over ¾ of a mile) of the construction site. If sensitive receptors are present within 4,000 feet of the well site, the distance setback requirements derived from the Health Risk Assessment (HRA) for construction activities are triggered. MM 4.12-1 and 4.12-2 establish similar standards to address the exposure of sensitive receptors to noise during construction and operations. Under MM 4.12-1 and 4.12-2, if sensitive receptors are present within *the screening contours, there is a presumption that noise levels will exceed applicable thresholds. If the permit applicant can demonstrate based on site-specific measurements in an Acoustic Noise Reduction Report that the activities will not exceed the Noise Standard, or if the applicant can implement attenuation measures as documented in the Acoustic Noise Reduction Report to achieve the applicable noise standard, then the applicant may conduct activities inside the screening distances specified in those mitigation measures. However, in no case may an applicant site a well closer than 210 feet to any sensitive receptor, with the distance being increased specifically for school property to 300 feet. As described in Section 4.3, Air Quality and Section 4.13, Noise, the setbacks in these mitigation measures are based specifically on local conditions, equipment, and drilling practices utilized in Kern County, as well as incorporating numerous conservative assumptions, to establish scientifically supported, safe setbacks for sensitive receptors. Further the mitigations for reduction of criteria pollutants to the equivalent of " no net increase" are part of the comprehensive package of mitigation along with the setbacks. Accordingly, the scientifically based setbacks and mitigation distance triggers established in these mitigation measures are more relevant than setbacks in other jurisdictions, in other states and in California, especially where those other setbacks are based on policy rather than risk assessments.*

Alternative 7, the 2,500-Foot Setback Alternative, is identical to the Project, except it would also amend Zoning Ordinance Chapter 19.98 to impose a 2,500-foot setback from sensitive receptors on wells. Sensitive receptors are defined in the SREIR (October 2020) as "single or multi-family dwelling units, places of public assembly (a legally permitted place where 100 or more people gather together in a building or structure for the purpose of amusement, entertainment, or retail sales), institutions, schools, or hospitals." A requirement that new oil and gas wells be set back 2,500 feet from sensitive receptors has been requested of the County and CalGEM in various public forums by a variety of advocates, including local environmental justice organizations. Although the Project includes setbacks to reduce health risk and noise impacts, advocates for a 2,500-foot setback assert that Alternative 7 would be more protective of sensitive receptors than would the Project by requiring even more space between permitted oil and gas wells and such sensitive receptors. As explained below, expert evidence indicates that Alternative 7 would not result in less severe environmental impacts than would the Project. However, given the public interest in a 2,500-foot setback, and in the interest of full disclosure, Alternative 7 has been carried forward for analysis as set forth herein.

Table 1-4 summarizes the impacts of the proposed Project and Alternatives 1 through ~~6~~*7*.

Table 1-4: Summary of Comparison of Alternative Impacts

	Project Summary of Impacts	**Alternative 1** No Project	**Alternative 2** CUP Alternative	**Alternative 3** Reduced Ground Disturbance Alternative	**Alternative 4** No Hydraulic Fracturing Alternative	**Alternative 5** Low-Emission EOR Technology Alternative	**Alternative 6** Recycled Water Alternative	***Alternative 7 Setback Alternative***
Aesthetics and Visual Resource	Significant and Unavoidable	Greater than Project	Same as Project	Less than Project	Same as Project	Same as Project	Greater than Project	*Same as Project*
Agricultural and Forest Resources	Significant and Unavoidable	Greater than Project	Same as Project	Less than Project	Same as Project	Same as Project	Same as Project	*Same as Project*
Air Quality	Significant and Unavoidable	Greater than Project	Greater than Project	Greater than Project	Greater as Project	Less than Project	Greater than Project	*Greater than Project*
Biological Resources	Significant and Unavoidable	Greater than Project	Greater than Project	Less than Project	Same as Project	Same as Project	Greater than Project	*Same as Project*
Cultural and Paleontological Resources	Significant and Unavoidable	Greater than Project	Same as Project	Less than Project	Same as Project	Same as Project	Greater than Project	*Same as Project*
Geology and Soils	Less than Significant	Greater than Project	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	*Same as Project*
Greenhouse Gas Emissions and Global Climate Change	Significant and Unavoidable	Greater than Project	Greater than Project	Greater than Project	Greater than Project	Less than Project	Greater than Project	*Greater than Project*
Hazards and Hazardous Materials/Public Health Risks	Less than Significant	Greater than Project	Greater than Project	Same as Project	Less than Project	Same as Project	Same as Project	*Same as Project*
Hydrology and Water Quality	Significant and Unavoidable	Greater than Project	Greater than Project	Same as Project	Less than Project	Same as Project	Less than Project	*Same as Project*
Land Use and Planning	Less than Significant	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	*Same as Project*
Mineral Resources	Less than Significant	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	*Same as Project*

Table 1-4: Summary of Comparison of Alternative Impacts

	Project Summary of Impacts	**Alternative 1** No Project	**Alternative 2** CUP Alternative	**Alternative 3** Reduced Ground Disturbance Alternative	**Alternative 4** No Hydraulic Fracturing Alternative	**Alternative 5** Low-Emission EOR Technology Alternative	**Alternative 6** Recycled Water Alternative	***Alternative 7 Setback Alternative***
Noise	Significant and Unavoidable	Greater than Project	Same as Project	Same as Project	Same as Project	Same as Project	Greater than Project	*Greater than Project*
Population and Housing	Less than Significant	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	*Same as Project*
Public Services	Less than Significant	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	*Same as Project*
Recreation	Less than Significant	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	*Same as Project*
Transportation and Traffic	Less than Significant	Greater than Project	Greater than Project	Greater than Project	Same as Project	Less than Project	Same as Project	*Same as Project*
Utilities and Service Systems	Significant and Unavoidable	Greater than Project	Same as Project	Same as Project	Same as Project	Same as Project	Less than Project	*Same as Project*

1.7.3 Environmentally Superior Alternative

An EIR must identify the environmentally superior alternative to the Project. Alternative 5 would be environmentally superior to the Project on the basis of the minimization or avoidance of physical environmental impacts. However, Section 15126.6(e)(2) of the CEQA Guidelines states that if the no Project alternative is found to be environmentally superior, "the EIR shall also identify an environmentally superior alternative among the other alternatives." The environmentally superior alternative is Alternative 5, the Low-Emission EOR Technology Alternative. Compared to the Project, Alternative 5 would have fewer environmental effects related to air quality, greenhouse gasses, and transportation and traffic. Moreover, Alternative 5 would not result in any environmental impacts that are greater than those of the Project.

1.8 Areas of Known Controversy

Areas of controversy were identified through written agency and public comments received during the 2015 Draft EIR scoping period. Those areas are included in 2015 FEIR Chapter 1.0, Executive Summary (in Volume 3 of this SREIR).

Scoping comments for this SREIR (provided in Section 2.4) identified the following general areas of controversy:

- Oil and gas drilling and extraction needs to end in California to address the climate change crisis.
- Oil and gas activities impact the health of people, specifically disadvantaged communities, that live too close to oil wells.
- A 2,500-foot setback from homes needs to be adopted for new and existing wells to protect people's health.
- Environmental justice analysis is required by CEQA.

1.9 Issues to Be Resolved

Section 15123(b) (3) of the CEQA Guidelines requires that an EIR contain issues to be resolved, which includes the choices among alternatives and whether or how to mitigate significant impacts. The major issues to be resolved regarding the Project include decisions by the lead agency as to whether or not:

- The Draft SREIR and 2015 FEIR adequately describe the environmental impacts of the Project;
- The recommended mitigation measures should be adopted or modified; and
- Additional mitigation measures need to be applied.

1.10 Summary of Environmental Impacts and Mitigation (~~2020~~ SREIR [August and October 2020]) and 2015 FEIR)

Tables 1-5 and 1-6, below, summarize the environmental impacts of the Project, mitigation measures, and unavoidable significant impacts identified and analyzed in Chapter 4, Environmental Setting, Impacts, and Mitigation Measures, for this SREIR *(August and October 2020)* and the 2015 FEIR.

The summary is shown as Table 1-5 for the ~~2020~~ SREIR *(August 2020) and SREIR (October 2020)* and Table 1-6 for the 2015 FEIR.

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Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

<table>
<tr><th>Impact</th><th>Level of Significance before Mitigation</th><th>Mitigation Measure(s)</th><th>Level of Significance after Mitigation</th><th>Applicable Tier</th></tr>
<tr><td colspan="5">Agricultural Resources</td></tr>
<tr><td>Impact 4.2-1
Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland) to Non-Agricultural Use</td><td>Potentially significant</td><td>MM 4.2.-1 For Oil and Gas Conformity Reviews that are 1) on land designated Prime, Farmland of Statewide Importance, or Unique Farmland; and 2) that have been actively farmed five years or more out of the last 10 years; and 3) have a water allocation sufficient for farming from any source shall have the following siting requirements:
A. All Oil and Gas Conformity Reviews permitted after the effective date of this ordinance shall have a site plan that contains no more than the following area limitations per well. All storage, parking, and oil activities shall be conducted only on the approved site plan acreage.
<table><tr><th>Subarea</th><th>Acreage (Gross)</th></tr><tr><td>Western</td><td>2.0</td></tr><tr><td>Central</td><td>3.0</td></tr><tr><td>Eastern</td><td>1.2</td></tr></table>
B. No permit for a new well shall be issued if the applicant has legacy unused oil and gas equipment on the same legal parcel. The legacy oil and gas equipment shall be removed inclusive of compliance with applicable legal requirements (e.g., well plugging and abandonment requirements under state or federal regulations), and restoration of the surface grade consistent with surrounding lands on the parcel completed before any new wells activity can commence. A full plan and details of actions needed to remove the legacy equipment shall be submitted with the site plan, be shown on a detail of the site plan, and be a condition of the approved permit. For farmland parcels in Tier 1, when both the surface and minerals are owned by the applicant, this measure does not apply.
C. Siting and construction of new disposal ponds are prohibited.</td><td>Impacts would be significant and unavoidable.</td><td>All Tiers</td></tr>
<tr><td>Impact 4.2-2
Conflict with Existing Zoning For Agricultural Use or a Williamson Act Contract</td><td>Less than significant</td><td>No mitigation measures are required.</td><td>Less than significant</td><td>All Tiers</td></tr>
<tr><td>Impact 4.2-3
Conflict with Existing Zoning for, or Cause Rezoning of, Forest Land or Timberland</td><td>No impact</td><td>No mitigation measures are required.</td><td>No impact</td><td>All Tiers</td></tr>
<tr><td>Impact 4.2-4
Result in the Loss of Forest Land or Conversion of Forest Land to Non-Forest Use</td><td>No impact</td><td>No mitigation measures are required.</td><td>No impact</td><td>All Tiers</td></tr>
</table>

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Impact 4.2-5 Involve Other Changes in the Existing Environment Which, Because of Their Location or Nature, Could Result in Conversion of Farmland to Non-agricultural Use or Conversion of Forest Land to Non-Forest Use	Potentially significant	**MM 4.2-2** To protect crops and structures adjacent to oil and gas activities on active agricultural lands, each Applicant/operator shall comply with the following mitigation measures set forth in other chapters of this Environmental Impact Report: a. Surface water runoff and drainage on the well pads shall be mitigated as described in mitigation measures for Hydrology and Water Quality. b. A Spill Prevention Countermeasure and Contingency Plan or Division of Oil Gas and Geothermal Resources Assembly Bill 1960 spill plan, as applicable, shall be prepared for the site and oil and chemical spills treated in accordance with the Division of Oil Gas and Geothermal Resources Senate Bill 4 Regulations for the site to protect adjacent farmland, as described in mitigation measures for Hazards. c. Speed limits for oil and gas trucks shall be posted on unpaved roads to reduce dust generation; in the absence of signage, speed limits shall be limited to 25 miles per hour (or an alternate, more stringent dust suppression standard as adopted by the San Joaquin Valley Air Pollution Control District), and Applicants shall attest that employees have been trained in the adopted speed limits. d. Unpaved roads shall be watered or otherwise treated for dust suppression and control as described in Mitigation Measure for Air Quality, unless speeds are restricted to 15 mph. e. Vehicle tracking control shall be installed where unpaved roads intersect with public paved roads, to prevent tracking of mud, dust, and weed seeds off site, unless speeds are restricted to 15 mph. This shall consist of a 50-foot length of a 3 inch-thick layer of gravel one inch or larger in diameter (or an alternate, more stringent dust suppression technique as approved by the San Joaquin Valley Air Pollution Control District). f. Stormwater control shall be required at construction sites during well drilling, reworking, and/or decommissioning as described in mitigation measures for Hydrology. g. Hazardous materials shall be stored within secondary containment as described in mitigation measures for Hazards. h. Overhead electrical or communication lines shall be shown on the Site Plan, and shall be aligned with existing roads, existing lines and easements, existing private driveways and/or parallel to tree or row crops. Underground pipelines serving the Project shall be shown on the Site Plan with locations marked and recorded with USAA, and periodically inspected and maintained as described in mitigation measures for Hazards.	Significant and Unavoidable	All Tiers
Impact 4.2-6 Result in the Cancellation of an Open Space Contract Made Pursuant to the California Land Conservation Act of 1965 or Farmland Security Zone Contract for Any Parcel of 100 or More Acres	No impact	No mitigation measures are required.	No impact	All Tiers
Impact 4.2-7 Substantially decrease the productivity of livestock grazing activity within Kern County	Less than significant	No mitigation measures are required	Less than significant	
Impact 4.2-8 Cumulative Impacts to Agricultural or Forest Resources	Potentially significant	Implement mitigation measure **MM 4.2-1**.	Significant and unavoidable	All Tiers

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Impact 4.2-9 Cumulative Impacts to Rangeland/Grazing Land	Potentially significant	No mitigation measures are required	Less than significant	
Air Quality				
Impact 4.3-1 Conflict With or Obstruct Implementation of the Applicable Air Quality Plan	Potentially significant	**MM 4.3-1** Consistent with the requirements of the San Joaquin Valley Air Pollution Control District Regulation II-Permits, the Applicant shall obtain an Authority to Construct permit and a Permit to Operate for any facility or equipment requiring a permit from the San Joaquin Valley Air Pollution Control District, such as stationary sources required to obtain permits pursuant to District Rule 2010. All emissions increases from permitted equipment shall comply with District Rule 2201. **MM 4.3-2** The Applicant shall develop and implement a Fugitive Dust Control Plan in compliance with San Joaquin Valley Air Pollution Control District fugitive dust suppression regulations. The Fugitive Dust Control Plan shall include: a. Name(s), address(es), and phone number(s) of person(s) responsible for the preparation, submission, and implementation of the plan. b. Description and location of operation(s). c. Listing of all fugitive dust emissions sources included in the operation. d. The following dust control measures shall be implemented: 1. All onsite unpaved roads shall be effectively stabilized using water or chemical soil stabilizers that can be determined to be as efficient as or more efficient for fugitive dust control than California Air Resources Board approved soil stabilizers, and that shall not increase any other environmental impacts including loss of vegetation. 2. All material excavated or graded will be watered to prevent excessive dust. Watering will occur as needed with complete coverage of disturbed areas. The excavated soil piles will be watered as needed to limit dust emissions to less than 20% opacity or covered with temporary coverings. 3. Construction activities that occur on unpaved surfaces will be discontinued during windy conditions when winds exceed 25 miles per hour and those activities cause visible dust plumes that exceed the SJVAPCD 20% opacity standard. 4. Track-out debris onto public paved roads shall not extend 50 feet or more from an active operation and track-out shall be removed or isolated such as behind a locked gate at the conclusion of each workday, except on agricultural fields where speeds are limited to 15 mph. 5. All hauling materials should be moist while being loaded into dump trucks. 6. All haul trucks hauling soil, sand, and other loose materials on public roads shall be covered (e.g., with tarps or other enclosures that would reduce fugitive dust emissions). 7. Soil loads should be kept below 6 inches or the freeboard of the truck. 8. Drop heights when loaders dump soil into trucks shall not exceed 5 feet above the truck. 9. Gate seals should be tight on dump trucks. 10. Traffic speeds on unpaved roads shall be limited to 25 miles per hour. 11. All grading activities shall be suspended when visible dust emissions exceed 20%. 12. Other fugitive dust control measures as necessary to comply with San Joaquin Valley Air Pollution Control District Rules and Regulations.	Less than significant	All Tiers

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		13. Disturbed areas shall not exceed those shown on the Site Plan. 14. Disturbed areas should be re-vegetated as soon as possible after disturbance if area is no longer needed for oil and gas activities. **MM 4.3-3** All off-road construction diesel engines not registered under California Air Resources Board's Statewide Portable Equipment Registration Program, which have a rating of 50 horsepower or more, shall meet, at a minimum, the Tier 3 California Emission Standards for Off-road Compression-Ignition Engines as specified in California Code of Regulations, Title 13, section 2423(b)(1) unless that such engine is not available for a particular item of equipment. In the event a Tier 3 engine is not available for any off-road engine larger than 100 horsepower, that engine shall be equipped with retrofit controls that would provide nitrogen oxides and particulate matter emissions that are equivalent to Tier 3 engine. a. All equipment shall be turned off when not in use. Engine idling of all equipment shall be limited to five minutes, except under exemptions specified in California Code of Regulations Title 13 Section 2449(d)(2)(A). b. All equipment engines shall be maintained in good operating condition and in proper tune per manufacturers' specifications. **MM 4.3-4** To further reduce emissions of oxides of nitrogen from on-road heavy-duty diesel haul vehicles: a. 2007 engines or pre-2007 engines shall comply with California Air Resources Board retrofit requirements set forth in California Code of Regulations Title 13 Section 2025. b. All on-road construction vehicles, except those meeting the 2007/California Air Resources Board-certified Level 3 diesel emissions controls, shall meet all applicable California on-road emission standards and shall be licensed in the State of California. This does not apply to worker personal vehicles. c. All on-road construction vehicles shall be properly tuned and maintained in accordance with the manufacturers' specifications.		
Impact 4.3-2 Result in a Cumulatively Considerable Net Increase of Any Criteria Pollutant for Which the Project Region is Non-Attainment Under an Applicable Federal or State Ambient Air Quality Standard	Potentially significant	Implement **MM 4.3-1** through **MM 4.3-4**, as described above.	Significant and unavoidable	All Tiers
Impact 4.3-3 Expose Sensitive Receptors to Substantial Pollutant Concentrations	Potentially significant	**MM 4.3-5** The Site Plan Application for an Oil and Gas Conformity Review shall include a Site Vicinity Figure showing the location of any sensitive receptor(s) within 4,000 feet of the construction site (potential impact area) for the proposed new well or other ancillary facility or equipment (excluding pipelines). a. If there are no sensitive receptors within this potential impact area, then no construction mitigation measures shall be required and the statement shall be placed as a note on the site plan. b. The well site and nearest property line of a sensitive receptor shall be permitted using both maps and coordinates on the map. If there are sensitive receptors within the potential impact area, then additional information must be provided showing the distance from the closest edge of the well pad to the property line of the nearest sensitive receptor. The minimum distances shall be as follows:	Significant and unavoidable	All Tiers

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		(nested table below)		

Well Depth (Feet)	Minimum Mitigation Trigger Distance from Well Site to Adjacent Property Line of an Existing Sensitive Receptor (Feet)
Western Subarea	
10,000	367
5,000	116
2,000	NA
Central Subarea	
10,000	367
5,000	116
2,000	NA
Eastern Subarea	
10,000	296
5,000	NA
2,000	NA

c. If the above distances cannot be met, and for existing wells that are subject to an Oil and Gas Conformity Review for redrilling or other permitted activities, the Applicant shall provide a site-specific risk assessment to the San Joaquin Valley Air Pollution Control District, which shall include implementation of one or more of the following risk minimization measures, or other such measures that are demonstrated by the Applicant to the San Joaquin Valley Air Pollution Control District, to achieve a level of risk less than the threshold risk level. Written confirmation shall be provided from the San Joaquin Valley Air Pollution Control District that the activity that is the subject of the application will not exceed the risk threshold. The following is a list of accepted risk minimization measures that shall be considered for inclusion by the San Joaquin Valley Air Pollution Control District:

1. Placement of engines in the potential impact area away from the sensitive receptors.
2. Utilize directional drilling to locate rig away further from the sensitive receptor(s).
3. Use of late-model engines, low-emission diesel products, alternative cleaner fuels (e.g., natural gas or liquefied petroleum gas), engine retrofit technology, add-on devices such as diesel particulate filters or oxidation catalyst, and/or other options as such become available to reduce emissions from off-road and other equipment.
4. Utilize electricity line power if available or deploy mobile solar panels with batteries for electricity.
5. Shutdown all equipment when not in use, and otherwise minimize engine idling by limiting idling to 15 minutes.
6. Use of automatic rigs.
7. Written confirmation from the identified sensitive receptor or receptors that the residents, business, church, or school agree to voluntary relocation or restrictions on receptor activities for the duration of construction activities with a specific timeframe for completion and details of any agreement.

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		MM 4.3-6 The following measures shall be implemented to address Valley Fever and pandemics: A. Applicants shall include in their Worker Environmental Awareness Program information on how to recognize the symptoms of Valley Fever and to promptly report suspected symptoms of work-related Valley Fever to a supervisor. A Valley Fever informational handout shall be provided to all onsite construction personnel. The handout shall, at a minimum, provide information regarding the symptoms, health effects, preventative measures, and treatment. Additional information and handouts can be obtained by contacting the Kern County Public Health Services Department. Onsite personnel shall be trained on the proper use of personal protective equipment, including respiratory equipment. National Institute for Occupational Safety and Health (NIOSH)-approved respirators shall be provided to onsite personal, upon request as part of the Worker Environmental Awareness Training Program. B. Applicants shall pay a $25 fee per individual well on Oil and Gas Conformity Reviews to be used by the Kern County Public Health Services Department for the specific purposes of continued Valley Fever education and outreach. C. Applicants shall implement all orders related to the COVID-19 pandemic or any other pandemic mandated by Kern County Public Health on well sites and related to worker safety.		
Impact 4.3-4 Result in Other Emissions Such as Those Leading to Odors Adversely Affecting a Substantial Number of People	Potentially significant	**MM 4.3-7** Applicant shall submit an Odor Complaint Management Plan to the County prior to receiving its first Site Plan conformity review approval. The Plan shall include a designated contact for odor complaints, creation of a log for odor complaints, and protocol for handling odor complaints. The Odor log and report files shall be available for public review upon request.	Significant and unavoidable	All Tiers
Impact 4.3-5 Result in Other Cumulatively Considerable Air Quality Impacts	Potentially significant	Implement MM 4.3-1 through MM 4.3-7, as described above. **MM 4.3-8** For criteria emissions, not required to be offset under a District rule as described in MM 4.3-1, and for Project vehicle and other mobile source emissions, the County will enter into an emission reduction agreement with the San Joaquin Valley Air Pollution Control District, pursuant to which the Applicant shall pay fees to fully offset Project emissions of NOx (oxides of nitrogen), ROG (reactive organic gases), PM10 (particulate matter of 10 microns or less in diameter), and PM2.5 (particulate matter of 2.5 microns or less in diameter) (including as applicable mitigating for reactive organic gases by additive reductions of particulate matter of 10 microns or less in diameter) (collectively, “designated criteria emissions”) to avoid any net increase in these pollutants. The air quality mitigation fee shall be paid to the County as part of the Site Plan review and approval process, and shall be used to reduce designated criteria emissions to fully offset Project emissions that are not otherwise required to be fully offset by District permit rules and regulations. As an alternative to paying the fee, an Applicant may reduce emissions for one or more designated criteria emissions through actual reductions in air emissions from other Applicant sources, as submitted to the County and validated by the District. This Project offset requirement alternative shall be enforced by the County and verified by San Joaquin Valley Air Pollution Control District, and must be approved in advance by the San Joaquin Valley Air Pollution Control District. If a voluntary emission reduction agreement is not executed by the County and San Joaquin Valley Air Pollution Control District, then each Applicant must mitigate for the full amount of designated criteria pollutants as verified by the San Joaquin Valley Air Pollution Control District, with evidence of such District-verified offsets presented as part of the Site Plan Conformity Review application documentation. Examples of feasible air emission reduction activities that may be funded by air quality fees paid by Applicant or proposed and implemented by the Applicant under the emission reduction agreement include, but are not limited to, the following: a. Replacing or retrofitting diesel-powered stationary equipment such as motors on generators, pumps and wells with electric or other lower-emission engines that are not subject to Title V reductions.	Significant and unavoidable	All Tiers

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		b. Replacing or retrofitting diesel-powered school, transit, municipal and other community mobile sources such as buses, car fleets, and maintenance equipment, with electric or other lower-emission engines. c. Reducing emissions from public infrastructure sources such as water and wastewater treatment and conveyance facilities, and reducing water-related emissions through water conservation and reclamation. d. Funding lower-emission equipment and processes for local businesses, schools, non-profit and religious institutions, hospitals, city and county facilities.		
Hydrology and Water Quality				
Impact 4.9-1 Violate any water quality standards or waste discharge requirements or otherwise substantially degrade surface or groundwater quality.	Potentially significant	**MM 4.9-1** The Applicant shall comply with all applicable federal, state, regional and local agency water quality protection laws and regulations, and commonly utilized industry standards, including (where applicable) obtaining coverage under the stormwater construction general permit and industrial general permit issued by the State Water Resources Control Board and complying with industry stormwater management standards for construction and operational activities. The applicant shall obtain all required permits from the Geologic Energy Management Division. **MM 4.9-2** A. Oil and Gas activities in Tier I shall comply with the following. 1. In areas subject to National Pollutant Discharge Elimination System stormwater permitting requirements, project applicants shall file a Notice of Intent to the State Water Resources Control Board to comply with the statewide General Permit for Discharges of Stormwater Associated with Construction Activities (Construction General Permit State Water Resources Quality Control Board Order No 2009-009-DWO) (as such permit may be amended, revised or superseded) prior to undertaking all ground-disturbing activities greater than one acre and shall prepare and implement a Stormwater Pollution Prevention Plan for construction activities on the Project site in accordance with the Construction General Permit. For facilities requiring coverage under the Construction General Permit, the site specific Stormwater Pollution Prevention Plan shall include measures to achieve the following objectives: (1) all pollutants and their sources, including sources of sediment associated with construction activity are controlled; (2) all non-stormwater discharges are identified and either eliminated, controlled and treated, (3) site Best Management Practices are effective and result in the reduction or elimination of pollutants in stormwater discharges and authorized non-stormwater discharges from construction activity and (4) stabilization Best Management Practices to reduce or eliminate pollutants after construction are completed. The Stormwater Pollution Prevention Plan shall be prepared by a qualified preparer and shall include the minimum Best Management Practices required for the identified risk level. The Stormwater Pollution Prevention Plan shall include a construction site monitoring program that identified requirements for dry weather visual observations of pollutants at all discharge locations and, as applicable, depending on the project risk level, sampling of site effluent and receiving waters. A qualified Stormwater Pollution Prevention Plan practitioner shall be responsible for implementing and all monitoring for the Best Management Practices as well as all inspection, maintenance and repair activities at the project site. If applicable, each project shall also implement and fully comply with the Industrial Storm Water Permit (Order No 97-03-DWO) and Kern County Municipal Stormwater Permit (Order No 5-01-120). All plans under these requirements shall be submitted to Kern County Public Works for review and approval. 2. Any operator of a facility that meets the following requirements is not required to be covered by the Construction General Permit (State Water Regional Control Board Memorandum dated 5-18-2010): a. discharges of stormwater runoff from oil and gas exploration, production, processing or treatment operations or transmission facilities, including field activities or operations that may be considered construction activity;	Less than significant	All Tiers

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		1. are not contaminated by contact with, or do not come into contact with, any overburden, raw material, intermediate products, finished product, byproduct or waste products; 2. are only contaminated by or only come into contact with sediment; and 3. pursuant to 40.C.F.R. § 122.26(c)(1) (iii) that do not contribute to a violation of a water quality standard. Any change to this State Water Regional Control Board determination will require full compliance with National Pollutant Discharge Elimination System requirements. 3. Any operator not subject to National Pollutant Discharge Elimination System stormwater permitting requirements shall implement Best Management Practices during construction and operation. All selected practices shall be shown on a drainage implementation plan and self-certified as complete by a licensed professional qualified in drainage and flood control issues. The plan shall be submitted to the Kern County Planning and Natural Resources Department. The following Best Management Practices shall be implemented and shown on the drainage implementation plan: a. Utilizing established facilities design and construction standards as applicable (e.g., American Society for the Testing and Materials (ASTM) American Petroleum Institute (API). b. Implementing good housekeeping and maintenance practices: i. Preventing trash, waste materials and equipment from construction storm water. ii. Maintaining wellheads, compressors, tanks and pipelines in good condition without leaks or spills. iii. Designing and maintaining graded pads to not actively erode and discharge sediment iv. Maintaining vehicles in good working order v. Providing secondary containment for all aboveground storage tanks and maintaining such containment features in good operating condition c. Implementing spill prevention and response measures: i. Utilizing preventative operating practices such as tank level monitoring, safe chemical handling and conducting regular inspections. ii. Developing and maintaining a spill response plan iii. Conducting spill response training for employees and have a process to ensure contractors have the necessary training iv. Maintaining spill response equipment on site. d. Implementing material storage and management practices: i. Preventing unauthorized access ii. Utilizing “run-on” and “run-off” control berms and swales iii. Stabilizing exposed slopes through vegetation and other standard slope stability methods. B. Oil and gas activities outside Tier 1 shall comply with all applicable state and federal stormwater management laws. For any oil and gas activity outside Tier I that is not subject to state or federal stormwater management laws, regulations or general permits, the Applicant shall prepare a drainage plan that complies with requirements to address runoff and the potential for impeding or redirecting 100-year flood		

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		flows. The drainage plan shall be prepared in accordance with the Kern County Grading Ordinance, Kern County Green Code, Development Standards and approved by the Kern County Department of Public Works, Floodplain Management Section. The drainage plan shall specify best management practices to prevent all construction pollutants from contacting stormwater, with the intent of keeping sedimentation or any other pollutants from moving offsite and into receiving waters. The requirements of the Plan shall be incorporated into design specifications. Recommended best management practices for the construction phase must be shown on a drainage plan, and shall include the following: a. Erosion Control - 1. Scheduling of construction activities to avoid rain events. 2. Implementing runoff erosion control methods consistent with the drainage plan when vegetation has been removed. b. Sediment Control - 1. Secure stockpiling of soil. 2. Installation of a stabilized construction entrance/exit and stabilization of disturbed areas. c. Non-stormwater Control - 1. Fueling and maintenance of equipment and vehicles shall be managed so as to prevent contamination of runoff from the site. 2. Concrete handling techniques shall be consistent with the drainage plan and shall comply with Mitigation Measure 4.14-15 (m). d. Waste and Material Management - 1. Managing construction materials, consistent with the drainage plan and designating construction staging areas in or around the Project site. 2. Stockpiling and disposing of demolition debris, concrete, and soil in compliance with regulatory requirements and consistent with the drainage plan. 3. Prompt removal and disposal of litter. 4. Disposal of demolition debris, concrete and soil in compliance with regulatory requirements for solid waste. 5. Provide and maintain secondary containment to prevent or eliminate pollutants from moving offsite and into receiving waters in compliance with Mitigation Measure 4.8-3. e. Post-Construction Stabilization - 1. Ensuring the stabilization of all disturbed soils per revegetation or application of a soil binder. C. If construction activities will alter federal jurisdictional waters, project applicants shall comply with the federal Clean Water Act Section 404 and Section 401 permitting and certification requirements. If construction activities will alter state waters, project applicants shall comply with California Department of Fish and Wildlife Streambed Alteration requirements. **MM 4.9-3** All drilling operations must either use a closed loop system to avoid discharges of drilling muds and fluids, or obtain coverage under the State Water Resources Control Board low threat discharge General Order (Waste Discharge Requirements General Order 2003-0003-DWQ), obtain individual Waste Discharge Requirements issued by the Central Valley Regional Water Quality Control Board for the unit, or obtain coverage under a general order issued by the Central Valley Regional Water Quality Control Board applicable to drilling ponds. Any surface ponds or sumps must be cleared of fluids and muds in accordance with the State Water Resources Control Board general order, applicable Water Discharge Requirements and Division of Oil Gas and Geothermal Resources regulations. Compliance with the State Water Resources Control Board or Central Valley Regional Water Quality Control Board low-threat discharge orders or Water Discharge		

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		Requirements, if closed-loop systems are not used, and applicable laws, regulations and standards will reduce potential surface water quality impacts from contact with drilling muds or fluids during drilling and construction to less than significant levels. After consultation with and approval by the Regional Water Board with jurisdiction over injection and groundwater, applicant shall provide for a tracer or some other reasonable method to allow well stimulation fluids to be distinguished from other fluids or chemicals for well stimulation permits. This could consist of an added tracer using an inert constituent that could be used to identify the presence of well stimulation fluids. Alternatively, it could be an intrinsic tracer, or some naturally occurring component that makes the well stimulation fluids chemically unique. Potential geochemical changes in the subsurface during injection or migration shall be considered. Use of a tracer shall be required to be disclosed to the public under Section 1788 of the SB 4 regulations. The regulations specifically require that the applicant require the composition and disposition of all well stimulation treatment fluids other than water, including "any radiological components or tracers injected into the well as part of the well stimulation treatment, a description of the recovery method, if any, for those components or tracers, the recovery rate, and specific disposal information for the recovered components or tracers a radiological component or tracer injected" (Section 1788 (15)). For any well stimulation treatment activity, the applicant shall not conduct well stimulation treatment activity until the State Water Resources Control Board, in consultation with the Central Valley Regional Water Quality Control Board, has approved either a groundwater monitoring plan or exclusion from groundwater monitoring for a given well, consistent with the State Water Resources Control Board Model Criteria for Groundwater Monitoring in Areas of Oil and Gas Well Stimulation. **MW 4.9-4** For any activity for which Chapter 19.98 applies, the Applicant shall not conduct any Class II injection activity regulated by the Underground Injection Control program, including enhanced oil recovery activities that discharge into any underground source of current or future beneficial use groundwater, including drinking water unless the aquifer has been exempted by the United States Environmental Protection Agency or injection has otherwise been authorized by the U.S. Environmental Protection Agency or by the California Geologic Energy Management Division in consultation and agreement by the State Water Resources Control Board, consistent with Public Resource Code 3131. **MM 4.9-5** For any activity for which Chapter 19.98 applies, the Applicant shall not discharge produced water into any surface disposal facility unless the facility has received the Waste Discharge Requirements from the Central Valley Regional Water Quality Control Board, or the need for Water Discharge Requirements has been waived by the Central Valley Regional Water Quality Control Board. As required by the SB 4 regulations, well stimulation treatment fluids and produced fluids from wells that have been stimulated cannot be stored, discharged, or disposed into surface ponds or pits. **MM 4.9-6** For any oil and gas activity within a Special Flood Hazard Area, the Applicant shall ensure that all constructed facilities are elevated or floodproofed in compliance with the requirements and standards found in the Kern County Floodplain Management Code Ordinance and Chapters 19.50 and 19.70 of the Kern County Zoning Code.		
Impact 4.9-2 Substantially decrease groundwater supplies or interfere substantially with groundwater recharge such that the project may impede sustainable groundwater management of the basin or conflict with or obstruct implementation of a water quality control plan or sustainable groundwater management plan	Potentially significant	Implement **MM 4.9-1** through **MM 4.9-6**, as described above, and the groundwater mitigation measures described in Section 4.17, Utilities and Service Systems.	Significant and unavoidable	All Tiers

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Impact 4.9-3 Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or through the addition of impervious surfaces, in a manner which would: (i) result in a substantial erosion or siltation on- or offsite; (ii) substantially increase the rate of amount of surface runoff in a manner which would result in flooding on-or offsite; (iii) create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff; or (iv) impede or redirect flood flows	Less than significant	Implement **MM 4.9-1** through **MM 4.9-6**, as described above, and the groundwater mitigation measures described in Section 4.17, Utilities and Service Systems.	Less than significant	All Tiers
Impact 4.9-4 Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or through the addition of impervious surfaces, in a manner which would: (i) result in a substantial erosion or siltation on- or offsite; (ii) substantially increase the rate of amount of surface runoff in a manner which would result in flooding on-or offsite; (iii) create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff; or (iv) impede or redirect flood flows	Less than significant	Implement **MM 4.9-1** through **MM 4.9-6**, as described above, and the groundwater mitigation measures described in Section 4.17, Utilities and Service Systems.	Less than significant	All Tiers
Impact 4.9-5 Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or through the addition of impervious surfaces, in a manner which would: (i) result in a substantial erosion or siltation on- or offsite; (ii) substantially increase the rate of amount of surface runoff in a manner which would result in	Less than significant	Implement **MM 4.9-1** through **MM 4.9-6**, as described above.	Less than significant	All Tiers

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
flooding on-or offsite; (iii) create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff; or (iv) impede or redirect flood flows				
Impact 4.9-6 Violate any water quality standards or waste discharge requirements or otherwise substantially degrade surface or groundwater quality	Less than significant	Implement **MM 4.9-1** through **MM 4.9-6**, as described above, and the groundwater mitigation measures described in Section 4.17, Utilities and Service Systems.	Less than significant	All Tiers
Impact 4.9-7 Place Housing within a 100-year Flood Hazard Area as Mapped on a Federal Flood Hazard Boundary or Flood Insurance Rate Map or Other Flood Hazard Delineation Map	No impact	No mitigation measures are required since the Project does not include housing development.	No impact	All Tiers
Impact 4.9-8 Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or through the addition of impervious surfaces, in a manner which would: (i) result in a substantial erosion or siltation on- or offsite; (ii) substantially increase the rate of amount of surface runoff in a manner which would result in flooding on- or offsite; (iii) create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff; or (iv) impede or redirect flood flows	Potentially significant	Implement **MM 4.9-1** through **MM 4.9-6**, as described above.	Less than significant	All Tiers
Impact 4.9-9 Expose People or Structures to a Significant Risk of Loss, Injury, or Death Involving Flooding, Including Flooding as a Result of the Failure of a Levee or Dam	Potentially significant	Implement **MM 4.9-1** through **MM 4.9-6**, as described above, and the groundwater mitigation measures described in Section 4.17, Utilities and Service Systems.	Less than significant	All Tiers

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Impact 4.9-10 In flood hazard, tsunami, seiche zones, risk release of pollutants due to project inundation	No impact	No mitigation measures are required.	No impact	All Tiers
Impact 4.9-11 Contribute to Cumulative Hydrology and Water Quality Impacts	Potentially significant	Implement **MM 4.9-1** through **MM 4.9-6**, as described above, and MM 4.17-3, 4.17-4, and 4.17-5 as described in Section 4.17, Utilities and Service Systems.	Significant and unavoidable	All Tiers
Noise				
Impact 4.12-1 Generation of a Substantial Temporary or Permanent Increase in Ambient Noise Levels in the Vicinity of the Project in Excess of Standards Established in the Local General Plan or Noise Ordinance, or Applicable Standards of Other Agencies	Potentially significant	**MM 4.12-1 Construction** The Site Plan Application for an Oil and Gas Conformity Review shall include a Site Vicinity Figure showing the location of any sensitive receptor(s) within 4,000 feet of the construction site (potential impact area) for the proposed new well or other ancillary facility or equipment (excluding pipelines). For any permit intending to process an Exploratory Well Permit with CalGEM, the Site Vicinity Figure shall show the locations of any sensitive receptors within 8,000 feet of the construction site. A sensitive receptor is defined as a single or multi-family dwelling unit, place of public assembly (a legally permitted place where 100 or more people gather together in a building or structure for the purpose of amusement, entertainment or retail sales), church, institution, school, or hospital. The site plan shall comply with the following details: **1. Determination of Distance** a. If there are no sensitive receptors within this potential impact area, then no construction mitigation measures shall be required and the statement shall be placed as a note on the site plan. b. The well site and nearest property line of a sensitive receptor shall be shown on the site plan using both feet and coordinates. If there is a neighborhood of sensitive receptors then the site plan shall identify the nearest group. If there are sensitive receptors within the potential impact area, then additional information must be provided showing the distance in feet and coordinates from the closest edge of the well pad to the property line of the nearest sensitive receptor. c. Table 1, below, shall be used to identify the mitigation trigger distance for the activity and a note placed on the site plan identifying the specific listed construction activity and mitigation trigger distance. d. If the nearest sensitive receptor property line is closer than the distance on Table 1, Construction Noise Mitigation Trigger Distance, then noise reduction measures to reduce impacts to the following Noise Standards shall be implemented: Noise Standards • For locations where the ambient level is below 65 dB, noise levels from construction activities may not increase the existing ambient level at the property line of the sensitive receptor by more than 5dB and may not exceed 65 dB at the property line of the sensitive receptor; • For locations where the ambient level is at or in excess of 65 dB, noise levels from construction activities may not increase the existing ambient level at the property line of the sensitive receptor by more than 1 dB.	Significant and Unavoidable	All Tiers

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		Table 1: Construction Noise Mitigation Trigger Distances		

Activity	Mitigation Trigger Distance (feet) For distance to closest sensitive receptor
Drilling (Well Advancement)	3,900
Drilling (Pull Out of Well/Borehole)	2,350
Large-Scale Exploratory Drilling[(a)]	7,900
Well Workover	2,355
Hydraulic Fracturing	2,965

Note: [(a)] Kenai Drill Rig #7

e. If a sensitive receptor is located within the noise mitigation trigger distances identified in Table 1, the activity location must either be relocated to achieve the distance as a setback, or an Acoustic Noise Reduction Report with mandatory noise reduction measures shall be prepared and submitted to show how to achieve the Noise Standard. The mitigation trigger distances and ambient noise levels are measured from the legal parcel property lin facing the well pad site of the closest sensitive receptor.

2. Acoustic Noise Reduction Report

a. An Acoustic Noise Reduction Report completed by a qualified professional shall be provided in conjunction with the application if the identified mitigation trigger distance will not be met. The report and submitted site vicinity map shall include all dimensions and detailed notes, based on the Acoustic Noise Reduction Report detailed in this measure.

b. Clearly marked distances in feet and with coordinates from the construction location on the well site to the nearest sensitive receptors both exterior wall of the receptor and the property line within the potential impact area.

c. Notes showing the average day-night level (DNL or Ldn) of ambient outdoor noise level at the proposed well location and at the property line of the nearest identified sensitive receptors that face the drill site over a 24-hour period.

d. Specific details from the Acoustic Noise Reduction Report specifying the level of project activity noise at the property line of the sensitive receptor allowed under the Noise Standard and the projected level of noise from the Project activity before implementation of noise reduction measures and after implementation of noise reduction measures.

e. The report shall identify and include the specific noise reduction method or methods that will be implemented and shall not include options for compliance. Any changes to the selected method or methods of compliance after approval will require submission of an amended Acoustic Noise Reduction Report reflecting the new selection.

1. Placement of a temporary sound attenuation wall(s) on property controlled by the applicant or with written permission from the property owner in compliance with Chapter 19.98.
2. Construction of a temporary berm on property controlled by the applicant or with written permission from the property owner in compliance with Chapter 19.98.
3. Specific orientation of the drilling equipment on the well site and modification of equipment to reduce noise impacts.
4. Implementation of other detailed sound reduction technologies or practices with evidence from the qualified professional of the reductions achieved.

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		5. Written confirmation from the occupants of the sensitive receptor(s) of their voluntary, temporary relocation or business restrictions during a defined construction period. **3. Monitoring** For the duration of the construction the following measurements shall be submitted to the Kern County Planning and Natural Resources Department at the required intervals. The measurements shall show achievement of the stated average day-night noise level stated on the Site Plan. If the measurement does not show the level is achieved, additional measures must be proposed and installed to prevent a stop work notice. Failure to submit within one business day after taking the required measurements will result in a stop work notice. a. 24 hours after completion of all noise attenuation measures and commencement of drilling or rework activities, the applicant shall take a measurement at the ambient level at the property line of the identified, nearest sensitive receptor. b. Every 14 days after commencement of activities, the applicant shall take a measurement at the ambient level at the property line of the identified, nearest sensitive receptor until completion of construction activities. c. All installed noise attenuation measures shall be maintained throughout all construction phase activities. **MM 4.12-2 Operation** **1. Mandatory Setbacks** The following are distances for a setback that can only be reduced by the processing and approval of a Conditional Use Permit with further environmental review under CEQA. a. New oil and gas wells shall be a minimum of two hundred and ten (210 feet) from the closest sensitive receptor for the following uses: single or multi-family dwelling unit, place of public assembly (a legally permitted place where 100 or more people gather together in a building, or structure, for the purpose of amusement, entertainment, or retail sales), church, institution or hospital. b. New oil and gas wells shall be a minimum of three hundred (300) feet of the legal parcel property line that contains a permitted public or private school. A single family or multi-family dwelling unit that may have home schooling activities shall use the single family dwelling unit distance. c. Geophysical testing methods using vibroseis vehicles to generate sound waves shall be a minimum of one hundred and fifty (150) feet from the closest occupied building, water well, sewer system, and septic tank. Geophysical testing methods using shotholes that employ explosives shall be a minimum of three hundred (300) feet from the closest occupied building, water well, sewer system, and septic tank and shall be in full compliance with all laws governing explosives. **2. Site Vicinity Figure** The Site Plan Application for an Oil and Gas Conformity Review shall include a Site Vicinity Figure showing the location of any sensitive receptor(s) within 4,000 feet of the construction site (potential impact area) for the proposed new well or other ancillary facility or equipment (excluding pipelines). A sensitive receptor is defined as a single or multi-family dwelling unit, place of public assembly (a legally permitted place where 100 or more people gather together in a building or structure for the purpose of amusement, entertainment or retail sales), church, institution, school, or hospital. The site plan shall comply with the following details: **3. Determination of Distance** a. If there are no sensitive receptors within this potential impact area, then no permanent operational noise mitigation measures shall be required and the statement shall be placed as a note on the site plan.		

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		b. If the well site is between two hundred and ten (210) feet and six hundred and fifty (650) feet of the well pad and nearest property line of a sensitive receptor other than a school, then it shall be shown on the site plan. If the well site is between three hundred (300) feet and six hundred and fifty (650) feet of the property line of a legally permitted public or private school, then it shall be shown on the site plan. If there is a neighborhood of sensitive receptors than the site plan shall identify the nearest group. c. Location of a well between two hundred and ten (210) feet and six hundred and fifty (650) feet of the well pad and nearest property line of a sensitive receptor shall require either details of the use of electric power for the well production which will mitigate the noise or the submittal of an Acoustic Noise Reduction Report if diesel power is used for the well production. **4. Acoustic Noise Reduction Report** a. An Acoustic Noise Reduction Report completed by a qualified professional shall be provided in conjunction with the application for any well sited between two hundred and ten (210) feet and six hundred and fifty feet (650) feet of the well pad and nearest property line of a sensitive receptor that will use diesel power for the well production. The report and submitted site vicinity map shall include all dimensions and detailed notes, based on the Acoustic Noise Reduction Report detailed in this mitigation measure. The report shall be based on the following noise standard' b. Noise Standards • For locations where the ambient level is below 65 dB, noise levels from operation of the well may not increase the existing ambient level at the property line of the sensitive receptor by more than 5dB and may not exceed 65 dB at the property line of the sensitive receptor. • For locations where the ambient level is at or in excess of 65 dB, noise levels from operation of the well may not increase the existing ambient level at the property line of the sensitive receptor by more than 1 dB. c. The site plan shall include notes showing the average day-night level (DNL or L_{dn}) of ambient outdoor noise level at the proposed well location and at the property line of the nearest identified sensitive receptors that face the drill site over a 24-hour period. d. Specific details from the Acoustic Noise Reduction Report specifying the level of operational noise at the property line of the sensitive receptor allowed under the Noise Standard and the projected level of noise from the operational noise before implementation of noise reduction measures and after implementation of noise reduction measures. e. If a permanent wall or solid barrier type material is utilized as a noise reduction measure, the holder of the Oil and Gas Conformity permit is responsible for obtaining any and all building permits required, maintenance and graffiti removal for the life of the oil well or group of wells being mitigated. No landscaping is required for the wall. The wall shall be removed when the well is abandoned and plugged. Requests to delete these requirements will require the processing and approval of a Conditional Use Permit.		
Impact 4.12-2 Exposure of Persons to, or Generate, Excessive Groundborne Vibration or Groundborne Noise Levels	Less than significant	No mitigation measures are required.	Less than significant	All Tiers

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Impact 4.12-3 For a Project Located Within the Vicinity of a Private Airstrip or an Airport Land Use Plan or, Where Such a Plan Has Not Been Adopted, Within Two Miles of a Public Airport or Public Use Airport, Would the Project Expose People Residing or Working in the Project Area to Excessive Noise Levels	Potentially significant	Implement **MM 4.12-1** and **MM 4.12-2**, as described above.	Significant and unavoidable	All Tiers
Impact 4.12-4 Cumulative Impact on Noise Receptors	Potentially significant	Implement **MM 4.12-1** and **MM 4.12-2**, as described above.	Significant and unavoidable	All Tiers
Utilities and Service Systems				
Impact 4.17-1 Exceed Wastewater Treatment Requirements of the Applicable Regional Water Quality Control Board	Less than significant	Implement stormwater mitigation measures, as described in Section 4.9, Hydrology and Water Quality.	Less than significant	All Tiers
Impact 4.17-2 Require or result in the relocation or construction of new or expanded water, wastewater treatment or storm water drainage, electric power, natural gas, or telecommunications facilities, the construction or relocation of which could cause significant environmental effects	Potentially significant	**MM 4.17-1** Prior to the issuance of building permits for an operations and maintenance building, the method of sewage disposal shall be as required and approved by the Kern County Public Health Services Department. Compliance with this requirement will necessitate that the Project proponent obtain the necessary approvals for the design of the septic system from the Kern County Engineering, Surveying and Permit Services Department. The septic system disposal field shall be located a minimum of 100 feet from a classified stream or 25 feet from a non-classified stream and shall not be located where it would impact State wetlands or special-status plant species.	Less than significant	All Tiers
Impact 4.17-3 Require or result in the relocation or construction of new or expanded water, wastewater treatment or storm water drainage, electric power, natural gas, or telecommunications facilities, the construction or relocation of which could cause significant environmental effects	Less than significant	Implement stormwater mitigation measures, as described in Section 4.9, Hydrology and Water Quality.	Less than significant	All Tiers

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Impact 4.17-4 Have sufficient water supplies available to serve the project and reasonably foreseeable future development during normal, dry and multiple dry years	Potentially significant	**MM 4.17-3** All Oil and Gas Conformity Reviews and Minor Activity Reviews shall provide information on any groundwater or reclaimed water will be used. Unmetered water wells cannot be used as a source of groundwater for the permit activity. Groundwater may only be used in a permitted activity from a water well equipped with a water meter. The Planning and Natural Resources Department shall compile the water use information in a report that shall be posted on the Kern County Planning and Natural Resources website for public use by December 31 of each calendar year. A copy shall be sent to all Groundwater Sustainability Agencies and the Kern County Water Agency after being posted on the website. The information submitted on the permit shall include the following data: A. The source and estimated amount of any groundwater being used in the permit activity. B. Confirmation that any water well used in permit activity is metered C. The source and estimated amount of any reclaimed water used in the permit activity. **MM 4.17-4** Public Notices for all Conditional Use Permits for oil and gas activities shall be sent to the appropriate Water Districts, Groundwater Authorities, and the Kern County Water Agency for review and comment on water availability and usage.	Significant and unavoidable	All Tiers
Impact 4.17-5 Result in a Determination by the Wastewater Treatment Provider which Serves or May Serve the Project that it has Adequate Capacity to Serve the Project's Projected Demand in Addition to the Provider's Existing Commitments	Less than significant	Implement **MM 4.17-1**, as described above.	Less than significant	All Tiers
Impact 4.17-6 Generate solid waste in excess of state or local standards, or in excess of the capacity of local infrastructure, or otherwise impair the attainment of solid waste reduction goals	Potentially significant	Implement the following: **MM 4.17- 2** During construction activities for Project facilities, the Applicant shall not store construction waste onsite for longer than the duration of the construction activity, or transport any waste to any unpermitted facilities. The Applicant shall also reduce construction waste transported to landfills by recycling solid waste construction materials, such as taking materials to recycling and reuse locations listed in the brochure on recycling construction and demolition materials available on the Kern County Public Works Department, website.	Less than significant	All Tiers
Impact 4.17-7 Comply with federal, State, and local management and reduction statutes and regulations related to solid waste	Potentially significant	Implement **MM 4.17-2**, as described above.	Less than significant	All Tiers

Table 1-5: 2020 SREIR Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Impact 4.17-8 Cumulative Impacts on Utilities and Service Systems	Potentially significant	Implement **MM 4.17-1** and **MM 4.17-2**, as described above. **MM 4.17–5** The Applicant shall pay a mitigation fee on each well of $250 for an Oil and Gas Conformity Review and $50 for each well in a Minor Activity Review. These funds shall be deposited into a Disadvantaged Community Drinking Water Grant Fund to be implemented by Kern County Public Health, which shall administer the selection and awarding of grants. Grants shall be available only for projects in disadvantaged communities in the Valley portion of Kern County, and may only be used for the design, permitting, and construction of physical improvements to water wells or water systems serving the identified Disadvantaged Community. The Disadvantaged Community may be within an incorporated city limits.	Significant and unavoidable with respect to water supply. Less than significant with respect to other public utilities, including municipal wastewater treatment, stormwater management, or landfills with mitigation	All Tiers

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Aesthetics				
Impact 4.1-1 Have a Substantial Adverse Effect on a Scenic Vista	Less than significant	No mitigation measures are proposed.	Less than significant	All Tiers
Impact 4.1-2 Substantially Damage Scenic Resources, Including, but Not limited to, Trees, Rock Outcroppings, and Historic Buildings within a State Scenic Highway	Less than significant	No mitigation measures are proposed.7	Less than significant	All Tiers
Impact 4.1-3 Substantially Degrade the Existing Visual Character or Quality of the Site and its Surroundings	Potentially Significant	**MM 4.1-1** The Applicant shall use existing public access easements or county maintained roads to access oil production areas. Existing private roads may only be used with the written permission of the property owner or private easement holder and written permission is only required if the surface owner is different from the mineral owner. The property owner's signature on the site plan statement will be considered permission for the use of all private roads shown on the site plan. New roads shall only be created if no existing public access easement exists for access to the oil production area or permission for legal use of an existing private access easement or private driveway/road cannot be obtained. Evidence that legal permission to use a private access or private driveway/road cannot be obtained shall be through two attempts by certified letter to the easement owner with two week reply times for each attempt. No response shall constitute lack of agreement to use the private access easement or private driveway/road. Permission for use of a private access instead of the signature on the site plan shall be from the property owner with a copy of the private easement or, in the case of a private driveway/road a highlighted plot plan showing the driveway/road being approved for use. Any new road shall not exceed 40 feet in graded width. **MM 4.1-2** All derricks, boilers, and other drilling equipment used to drill, repair, clean out, deepen or redrill any well with oil, gas, or other hydrocarbon shall be removed from the drill site within 90 days after completion of production tests or after abandonment of any well. Earthen sumps used in drilling shall be filled within 90 days after any well has been placed in production (unless such sumps are to be used within six months for the drilling of another well), and any sump used in productions shall be filled after its abandonment and restored to a uniform grade within ninety days. **MM 4.1-3** Sumps and ponds shall be permitted only to the extent authorized by the Central Valley Regional Water Quality Control Board (via waiver, Waste Discharge Requirements, or other form of authorized written documentation) and shall comply with all applicable legal requirements and mitigation measures for sumps serving as storage, percolation or evaporation ponds for produced water. **MM 4.1-4** Except where located within agricultural land, new oil or gas tanks located within 200 feet of any sensitive receptor shall be partially screened from public view by shrubs, trees or solid screen fencing. Similarly, new pump sites (including multiple well pump sites) within 500 feet of any dwelling must be surrounded by a fence, at least 6 feet in height, constructed of dark-colored chain-link with wood or metal slates, dark green or brown fabric material or solid wall. The height of all new pumping units shall not exceed 80 feet, and shall be painted in accordance with the Kern County Zoning Ordinance. **MM 4.1-5** Project signage is limited to directional, warning, safety, security and identification signs in connection with oil, gas, or other hydrocarbon drilling and development operations in accordance with Chapter 19.84.135 of the Kern County Zoning Ordinance.	Significant and unavoidable	All Tiers

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Impact 4.1-4 Create a New Source of Substantial Light or Glare that Would Adversely Affect Day or Nighttime Views in the Area	Potentially significant	**MM 4.1-6** All new lighting, including permanent nighttime lighting, safety, security, and operational lightening shall comply with the standards in Kern County Zoning Chapter 19.81 - Outdoor Lighting "Dark Sky Ordinance."	Significant and unavoidable	All Tiers
Impact 4.1-5 Contribute to Cumulative Aesthetic Impacts	Cumulatively considerable	Implement **MM 4.1.1** through **4.1.6**, as described above. No additional feasible mitigation measures exist to avoid or reduce significant adverse cumulative impacts to aesthetics to a less than significant level.	Significant unavoidable	All Tiers
Biological Resources				
Impact 4.4-1 Have a Substantial Adverse Effect, either Directly or through Habitat Modifications, on any Species Identified as a Candidate, Sensitive, or Special Status Species in Local or Regional Plans, Policies, or Regulations or by the California Department of Fish and Wildlife or the United States Fish and Wildlife Service	Potentially significant	**MM 4.4-1** The applicant shall use a qualified biologist for all work on reports submitted for any application for project permit. The qualified biologist must have a Bachelor of Science Degree or Bachelor of Arts Degree in biology or related environmental science, have demonstrated familiarity with the natural history, habitat affinities and identification of Covered Species of the San Joaquin Valley and have conducted work in California for at least one (1) year of field level reconnaissance survey work in the San Joaquin Valley. The resume of the biologist preparing any report submitted for permits shall be included in the report. Lack of these specific qualifications will result in immediate rejection of the report without further review. A qualified biologist shall conduct a biological reconnaissance survey in potential special-status species habitat to advise the project proponent of potential project impacts, potential surveying needs, and advise on the need for focused special status surveys. Early consultation with United States Fish and Wildlife Service and California Department of Fish and Wildlife will also inform project proponents of additional recommendations. Based on the information gathered from the biological reconnaissance survey and any informal consultation with United States Fish and Wildlife Service and California Department of Fish and Wildlife, focused/protocol surveys shall be conducted by a qualified biologist consistent with protocol study timelines in advance of submittal of the permit application to determine the presence/absence of sensitive species protected by state and federal Endangered Species Acts and potential project impacts to those species. No ground disturbance activities can occur on any well site without an approved Oil and Gas permit. The survey shall be conducted in accordance with the most current standard protocol of the United States Fish and Wildlife Service and California Department of Fish and Wildlife. The purpose of focused/protocol surveys is to confirm the presence or absence of any species listed as threatened or endangered under the federal Endangered Species Act. threatened or endangered under the California Endangered Species Act, rare or endangered in the California Native Plant Protection Act, or designated as fully-protected in the California Fish and Game Code (collectively, "Protected Species"), and to confirm the presence or absence of any other species considered "sensitive" under California Environmental Quality Act ("Sensitive Species"), and to identify and implement avoidance and minimization measures for such species. The surveys shall be conducted in accordance with all currently-applicable presence and absence survey and/or species protocols established by the United States Fish and Wildlife Service and the California Department of Fish and Wildlife ("Species Protocols"). In the absence of any approved protocols, the survey shall extend for a minimum of 250 feet from all areas where any ground disturbance activities would occur, provided that permission to access has been obtained. As an alternative to individual pre-disturbance surveys for each application, and after consultation with and concurrence by the California Department of Fish and 'Wildlife and the United States Fish and Wildlife Service, multiple parcels or areas of oil and gas production lands (including lands which may have multiple surface or mineral ownership) may be consolidated for the purpose of more efficiently managing pre-disturbance surveys and determinations regarding the absence of protected species in areas of proposed new ground disturbance activities. A biological monitor with the same qualifications as a qualified biologist shall be present during ground-disturbing activities in project locations that have special-status species habitat or are adjacent to potential special-status species habitat. Within 30 days before any ground-disturbing activities in special-status species habitat, the qualified biologist shall conduct a pre-disturbance survey to record existing conditions of the site, determine if conditions have changed since the reconnaissance or focused/protocol surveys were conducted, and to determine where sensitive species avoidance buffers will be established	Less than significant	All Tiers

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

<table>
<tr><th>Impact</th><th>Level of Significance before Mitigation</th><th>Mitigation Measure(s)</th><th>Level of Significance after Mitigation</th><th>Applicable Tier</th></tr>
<tr><td></td><td></td><td>
MM 4.4-2 No incidental take of any species listed as threatened or endangered under the federal Endangered Species Act, threatened or endangered under the California Endangered Species Act, rare or endangered in the California Native Plant Protection Act, or designated as fully-protected in the California Fish and Game Code (Protected Species) may occur unless the incidental take is authorized by applicable state and federal wildlife agencies in the form of a permit or other written authorization, an approved state or federal conservation plan, or in accordance with an approved regional plan such as the Draft Valley Floor Habitat Conservation Plan and/or Natural Community Conservation Plan.
MM 4.4-3 Protective buffers shall be used, where effective in the opinion of the qualified biologist, to avoid any unauthorized incidental take of Protected Species, and to minimize any incidental take of Sensitive Species, by separating the planned disturbance area from any locations where the qualified biologist has detected the presence of Protected Species or Sensitive Species. Protective buffers shall be delineated using brightly colored stakes and/or flagging or similar materials and remain until construction activities are complete, at which time of completion the buffers must be removed. Protective buffers shall be established around active dens and/or burrows of special-status animal species, or populations of special-status plant species to avoid unauthorized take of protected species as listed in the table below. The protective buffer distance shall be increased if required to avoid unauthorized incidental take of any Protected Species as determined by a qualified biologist. Protective buffer distances and other avoidance measures that may be implemented to avoid impacts to Protected Species or Sensitive Species must be consistent with the United States Fish and Wildlife Service and/or the California Department of Fish and Wildlife, and shall be implemented and overseen by the qualified biologist.
Disturbance Buffers for Sensitive Resources
<table>
<tr><td>Sensitive Resource</td><td>Buffer Zone from Disturbance (feet)</td></tr>
<tr><td>Potential San Joaquin kit fox den</td><td>50</td></tr>
<tr><td>Known San Joaquin kit fox den</td><td>100</td></tr>
<tr><td>Natal San Joaquin kit fox den</td><td>500</td></tr>
<tr><td>Atypical San Joaquin kit fox den</td><td>50</td></tr>
<tr><td>Rodent burrows</td><td>50</td></tr>
<tr><td>Listed bird species active nests</td><td>0.5 mile</td></tr>
<tr><td>Burrowing owl burrow (breeding and non-breeding season)</td><td>Pursuant to California Department of Fish & Wildlife guideline (see Table 4.4-85)</td></tr>
<tr><td>San Joaquin coachwhip, silvery legless lizard, coast horned lizard</td><td>30</td></tr>
<tr><td>American badger:
Non-maternity dens
Maternity dens</td><td>
50
200</td></tr>
<tr><td>Special-status plants</td><td>50</td></tr>
</table>
MM 4.4-4 Occupied burrowing owl burrows shall not be disturbed during the species nesting season (February 1 through August 31). The following distances shall be maintained between all disturbance areas and burrowing owl nesting sites (Table 4.4-85).
Table 4.4-85 Setback Distances for Burrowing Owl Nesting Sites by Level of Proposed Project Impacts
<table>
<tr><th colspan="3">Location</th></tr>
<tr><td>Nesting sites</td><td>Nesting sites</td><td>Nesting sites</td></tr>
<tr><th colspan="3">Time of Year</th></tr>
</table>
</td><td></td><td></td></tr>
</table>

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

<table>
<tr><th>Impact</th><th>Level of Significance before Mitigation</th><th>Mitigation Measure(s)</th><th>Level of Significance after Mitigation</th><th>Applicable Tier</th></tr>
<tr><td></td><td></td><td>
<table>
<tr><th>April 1–Aug 15</th><th>Aug 16–Oct 15</th><th>Oct 16–Mar 31</th></tr>
<tr><td colspan="3">Project Impact Level</td></tr>
<tr><td colspan="3">Low</td></tr>
<tr><td>656 feet (200 meters)</td><td>656 feet (200 meters)</td><td>164 feet (50 meters)</td></tr>
<tr><td colspan="3">Medium</td></tr>
<tr><td>1,640 feet (500 meters)</td><td>656 feet (200 meters)</td><td>328 feet (100 meters)</td></tr>
<tr><td colspan="3">High</td></tr>
<tr><td>1,640 feet (500 meters)</td><td>1,640 feet (500 meters)</td><td>1,640 feet (500 meters)</td></tr>
</table>
Burrowing owls present in proposed disturbance areas or within 500 feet or as specified under an approved Habitat Conservation Plan (as identified during pre-disturbance surveys) outside of the breeding season (between September 1 and January 31) may be moved away from the disturbance area using passive relocation techniques approved by the California Department of Fish and Wildlife. Passive relocation techniques in the California Department of Fish and Wildlife Staff Report on Burrowing Owl Mitigation Guidelines (California Department of Fish and Game 2012) include installing one-way doors in burrow entrances for 48 hours, to ensure the owl(s) have left the burrow, daily monitoring during the passive relocation period, and collapsing existing burrows to prevent reoccupation. A minimum of one or more weeks will be required to relocate the owl(s) and allow for acclimatization to alternate off-site burrows. Prior to burrow exclusion or eviction, a burrowing owl management plan shall be prepared and approved by the California Department of Fish and Wildlife. Destruction of burrows shall occur only pursuant to a management plan for the species approved by the California Department of Fish and Wildlife; burrow excavation shall be conducted by hand whenever possible.
As an alternative to passive relocation, occupied burrows identified off-site within 500 feet of construction activities may be buffered with hay bales, fencing (e.g. sheltering in place), or as directed by the qualified biologist and the California Department of Fish and Wildlife, to avoid disturbance of burrows.
MM 4. 4-5 The qualified biologist surveys shall determine whether active bat maternity roosts are located in or within 250 feet of any disturbance area. All active bat maternity roosts shall be avoided during breeding periods, including postponing disturbance activities. If an active Sensitive or Protected Species bat maternity roost location is proposed to be disturbed, the qualified biologist shall consult with, the United States Fish and Wildlife Service and California Department of Fish and Wildlife to identify any additional minimalization measures which the qualified biologist determines with the wildlife agencies can actually be implemented based on field conditions. All such measures must be implemented for project activities.
MM 4.4-6 Any potential San Joaquin kit fox dens (as defined in United States Fish and Wildlife Service 2011a) detected during reconnaissance or focused/protocol surveys shall be reevaluated by the qualified biologist for species activity no more than 30 days prior to the commencement of ground disturbance in the required pre-construction survey. Potential kit fox dens shall be marked and a 50-foot avoidance buffer shall be delineated using brightly colored stakes and flagging or similar materials to prevent inadvertent damage to the potential den. If the qualified biologist determines that an unoccupied potential den cannot be avoided, the den may be hand excavated in accordance with the United States Fish and Wildlife Service Standardized Recommendations for Protection of the Endangered San Joaquin Kit Fox Prior to or During Ground Disturbance (United States Fish and Wildlife Service 2011). If species activity is detected, the location shall be identified as a "known" kit fox den in accordance with the U.S. Fish and Wildlife Service species guidelines (United States Fish and Wildlife Service 2011). A minimum 100-foot buffer from any disturbance area shall be maintained for known dens and a minimum 500-foot buffer from any disturbance area shall be maintained for natal dens. No excavation of a known or natal den shall occur without prior authorization from the United States Fish and Wildlife Service and the California Department of Fish and Wildlife. For activities occurring on land covered under an approved federal and/or State incidental take authorization, the requirements set forth in those documents shall be implemented. Other standard measures to protect San Joaquin kit fox, including capping pipes, covering trenches, adding exit ramps to excavated areas, shall be implemented in accordance with MM 4.4-15.
</td><td></td><td></td></tr>
</table>

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		MM 4.4-7 Occupied American badger dens detected during pre-disturbance surveys shall be flagged and ground-disturbing activities avoided within 50 feet of the den. Maternity dens shall be avoided and a minimum 200-foot buffer from disturbance shall be maintained during pup-rearing season (February 15 through July 1). Maternity dens must be avoided to the maximum extent feasible in the opinion of the qualified biologist. If an active maternity den is proposed to be disturbed, the qualified biologist, shall consult with the California Department of Fish and Wildlife to identify any appropriate additional minimization measures which the qualified biologist determines, with the wildlife agencies, can actually be implemented based on field conditions. All such measures must be implemented for project activities. **MM 4.4-8** Pre-disturbance surveys for all sites located above 2,000 feet in elevation, or within 200 feet down gradient from the 2,000-foot elevation contour line, shall specifically survey for any golden eagle nests located within 2 miles of the site. If golden eagle nests are detected by the surveys, the qualified biologist shall conduct a nest-specific viewshed analysis. No disturbance may occur within 0.25 mile, or within 0.5 mile of the viewshed of an active golden eagle nest unless otherwise authorized by State and federal wildlife agencies. The United States Fish and Wildlife Service and California Department of Fish and Wildlife must be notified prior to the commencement of any disturbance activities within 1 mile of an active golden eagle nest to avoid golden eagle take. **MM. 4.4-9** All sites located above 2,000 feet in elevation, or within 200 feet down gradient from the 2,000-foot elevation contour line, shall implement the following measures to avoid and minimize potential adverse impacts to the California condor: a. The site shall, at all times, be maintained to avoid any trash, debris, food sources and microtrash, such as bottle caps, that could be ingested by or attract California condor. Trash shall be disposed in animal-proof containers as required in **MM 4.4-19**. b. The Worker Environmental Awareness Program described in **MM 4.4-18** shall include information about microtrash and potential effects to California condor, and shall prohibit the disposal of trash and microtrash on the site of oil and gas activities. c. If a condor is observed in a proposed construction site, all disturbance activities must immediately cease within 500 feet of the condor until the animal has moved from the site. If condor occurrence persists, the United States Fish and Wildlife Service and the California Department of Fish and Wildlife must be contacted to identify appropriate avoidance measures and those measures must be implemented by the qualified biologist used by the applicant. prior to initiating or resuming any disturbance activity. d. All condor observations shall be reported within 24 hours to the United States Fish and Wildlife Service and the California Department of Fish and Wildlife. e. All tanks, liquid storage facilities, and any open area containing water or other liquid materials, including drilling sumps, must be covered or otherwise shielded in a manner that prevents condor intrusion and potential entrapment. f. No overhead transmission lines may be used at the site without the prior approval of the United States Fish and Wildlife Service and the California Department of Fish and Wildlife. **MM 4.4-10** Pre-disturbance surveys for active bird nests must be conducted no more than 10 days prior to the commencement of disturbance. Surveys shall follow United States Fish and Wildlife and California Department of Fish and Wildlife guidance and/or protocols, as applicable. If no active nests or nesting birds are identified, then Project construction activities may proceed and no further mitigation measures for nesting birds are required. If active nest(s) are identified, the active nest(s) should be continuously surveyed for the first 24 hours after detection, to establish a behavioral baseline prior to any construction-related activities. Once construction commences, all nests shall be continuously monitored to detect any behavioral changes as a result of the Project (i.e., nest avoidance or abandonment). If behavioral changes are observed, the work causing that change shall cease until the applicant qualified biologist consults with the California Department of Fish and Wildlife and the United States Fish and Wildlife and the qualified biologist used by the applicant implements the recommended measures. During such times as the qualified biological monitor is not onsite while construction workers are onsite, a minimum nondisturbance buffer of 250 feet shall be established around active nests and a 500-foot no-disturbance buffer around the nests of raptors until the breeding season has ended, or until a qualified biologist has determined that the birds have fledged and are no longer reliant upon the nest or parental care for survival, and any adult birds are no longer occupying the nest. Deviations from these no disturbance buffers may be implemented if the qualified biologist concludes that work within the buffer area would not cause nest avoidance or abandonment (e.g., when the disturbance area would be concealed from a nest site by topography) provided that notification of this determination of a deviation in the no-disturbance buffer is provided by the qualified biologist no less than 15 days in advance to the California Department of Fish and Wildlife and the United States Fish and Wildlife.		

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		MM 4.4-11 The following measures will be implemented to avoid take of blunt-nosed leopard lizard and to ensure protection of these animals during Project activities: a. Project activities will avoid all potential burrows that may be occupied by blunt-nosed leopard lizards. Suitable burrows within and adjacent to potential habitat for the species should be avoided by a minimum distance of 50-feet in all areas where ground-disturbing Project activities will occur. b. No more than one year prior to ground disturbing activities, focused surveys following current California Department of Fish and Wildlife and United States Fish and Wildlife protocols for detection of this species or other methods approved by both agencies shall be conducted in all potential blunt-nosed leopard lizard habitat within the work site and a 250-foot buffer area. If no individual blunt-nosed leopard lizards are observed during focused surveys, and surveys are current (e.g., completed in the same calendar year), then Project activities may proceed. c. If blunt-nosed leopard lizards are detected during focused surveys, a blunt-nosed leopard lizard avoidance plan shall be prepared for the Project that will result in avoidance of incidental take of this species unless take is separately authorized under a Natural Communities Conservation Plan and appropriate federal authorization is obtained. At a minimum, the blunt-nosed leopard lizard avoidance plan shall be provided to the California Department of Fish and Wildlife and the County, and shall contain the following elements: 1. A Worker Environmental Awareness Program shall be implemented for all construction personnel before construction begins (see **MM 4.4-18**). 2. During periods that are optimal for blunt-nosed leopard lizard activity (early spring through late fall), a qualified biologist will be present during all ground disturbing activities. The qualified biologist will check the Project site(s) and access route(s) daily during the blunt-nosed leopard lizard active season to determine presence or absence of lizards in or near the work areas. Monitoring by a qualified biologist is not required during periods of inactivity (the winter season). 3. All open trenches or excavations shall be covered at the end of each workday or protected with the use of exclusion fencing to prevent wildlife entrapment. If an excavation is too large to cover, escape ramps shall be installed at an incline ratio of no greater than 2:1. All trenches and pipes shall be inspected for the presence of wildlife each day prior to the commencement of work. If blunt-nosed leopard lizards are observed at the work site during construction, construction shall cease within a 250-foot radius and the United States Fish and Wildlife Service and the California Department of Fish and Wildlife shall be consulted to determine what additional measures would be necessary to prevent take of this species. 4. Offsite locations where blunt-nosed leopard lizards have been observed or are likely to occur shall be clearly marked to prevent workers from driving off the road and to prevent inadvertent destruction of burrows. Barriers, such as exclusionary fencing may be installed. All construction equipment and construction personnel vehicles will be checked prior to moving to ensure no blunt-nosed leopard lizard are under equipment/vehicles. 5. A speed limit of 10 miles per hour shall be posted and observed within 0.25 miles of any reported blunt-nosed leopard lizard observation. 6. Construction activities shall avoid burrows that may be used by blunt-nosed leopard lizards. Any location of proposed construction activity with potential to collapse or block burrows (i.e., stockpile storage, parking areas, staging areas, trenches) will be identified prior to construction in the blunt-nosed leopard lizard avoidance plan and approved by the qualified biologist. The qualified biologist may allow certain activities in burrow areas if the combination of soil hardness and activity impact is not expected to collapse burrows and no blunt-nosed leopard lizards have been found during pre-Project surveys in the impact area. 7. All individual blunt-nosed leopard lizards observed above-ground will be avoided. Any individual blunt-nosed leopard lizard that may enter the Project site(s) would be allowed to leave unobstructed, and on its own accord. If a blunt-nosed leopard lizard is detected during biological monitoring or observed at any other point, the California Department of Fish		

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Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		and Wildlife and the United States Fish and Wildlife Service shall be notified to determine what additional measures would be necessary to prevent take of the species. **MM 4.4-12** The Applicant shall comply with the following: a. Plant surveys for Protected Species and Sensitive Species must be completed by a qualified biologist during the appropriate blooming periods for species identification and detection. Plant surveys shall be conducted in accordance with all applicable protocols established by the United States Fish and Wildlife Service and the California Department of Fish and Wildlife for particular plant species ("Plant Survey Protocol"), and shall extend 50 feet from areas where any new disturbance would occur unless a greater survey distance is specified in the Plant Survey Protocol. All detected plant populations of Protected Species and Sensitive Species shall be identified in the field during the surveys with temporary flags or other visible materials to avoid and minimize impacts to the plant populations from any disturbance activities. b. No incidental take or relocation of any plant listed under the federal Endangered Species Act, the California Endangered Species Act, or the California Native Plant Protection Act may occur unless the incidental take is authorized by the United States Fish and Wildlife Service and/or the California Department of Fish and Wildlife in a permit or other authorization, or in an approved Habitat Conservation Plan or Natural Communities Conservation Plan. If focused plan surveys detect the presence of any listed plant, the plant populations shall be buffered from disturbance activities by implementing applicable impact avoidance protocols established by the United States Fish and Wildlife Service and/or the California Department of Fish and Wildlife unless incidental take authority is obtained. Projects covered under incidental take authority shall conduct activities in accordance with the take authorization. The qualified biologist may consult with the California Department of Fish and Wildlife to determine the recommended buffer distances required to prevent incidental take of a listed plant if avoidance protocols have not been established for the species. The qualified biologist shall confirm that all applicable listed plant buffers have been implemented prior to the commencement of any disturbance activity. c. Sensitive species plant populations which are not Protected Species that may be impacted by new ground disturbing activities must be avoided by a 50-foot buffer, as delineated and implemented by a qualified biologist used by the applicant. **MM 4.4-13** A Worker Environmental Awareness Program shall be developed and implemented for all personnel that could access the site prior to commencing any disturbance activities. The program shall consist of an on-site or center presentation that will describe the locations and types of sensitive plant, wildlife, and sensitive natural communities (collectively, “Biological Resources”) on and near the site, an overview of the laws and regulations governing the protection of Biological Resources, the reasons for protecting the Biological Resources, the specific protection and avoidance measures that are applicable to the site, and the identity of designated points of contact should questions or issues arise, including the qualified biologist. The program shall provide training to recognize, avoid and report to applicable qualified biologists any Biological Resources on the site. a. The Worker Environmental Awareness Program shall emphasize the need to avoid contact with onsite wildlife, and avoid entry into areas where Biological Resources have been identified based on pre-disturbance field surveys and to implement the buffer avoidance or other protection measures established by the United States Fish and Wildlife Service shall be identified California Department of Fish and Wildlife or required by the Biological Resource mitigation measures. The training shall emphasize the importance of not feeding or domesticating wildlife and the need to avoid any trash, microtrash, or potential food disposal onsite except in animal-proof containers emptied daily to avoid attracting, or causing adverse impacts to special status wildlife. b. All onsite personnel must sign a statement verifying that they have completed the Worker Environmental Awareness Program, and that they understand and agree to implement the biological requirements for the worksite. If signed employee statements are not available, documentation may be provided by Worker Environmental Awareness Program training records, which shall be kept by the Applicant for a minimum of 5 years. Each Applicant shall maintain a list of all persons who have completed the training program, and shall provide the list to the County or to state and federal wildlife agency representatives upon request. **MM 4.4-14** The following additional measures shall be implemented to avoid and minimize potential significant adverse impacts to Protected and Sensitive Species:		

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		a. All vehicles shall observe a 20-mile-per-hour speed limit in all areas of disturbance and on unpaved roads unless otherwise posted. Off-road traffic outside of designated access routes is prohibited. Speed limit signs shall be posted in visible locations at the point of site entry and at regular intervals on all unpaved access roads. b. All disturbance activities, except emergency situations or drilling that may require continuous operations, shall only occur during daylight hours. Night time disturbance activity for drilling purposes shall use directed lighting, shielding methods, and comply with applicable lighting mitigation measures. c. All food-related trash items and all forms of microtrash, such as wrappers, cans, bottles, bottle tops, and food scraps shall be disposed of in closed, animal proof containers and removed daily from the site. d. Excavations, spoils piles, access roadways, and parking and staging areas shall subject to dust control as set forth in the dust control mitigation measures. e. The use of herbicides for vegetation control shall be restricted to those approved by the United States Fish and Wildlife Service and the California Department of Fish and Wildlife. No rodenticides shall be used on any site unless approved by the United States Fish and Wildlife Service, and the California Department of Fish and Wildlife, and shall observe label and other restrictions mandated by the United States Environmental Protection Agency, California Department of Food and Agriculture, and state and federal laws and regulations. For split estates, no herbicides for vegetation control may occur in Tier 2 areas without surface owner approval. f. No plants or wildlife shall be collected, taken, or removed from the site or any adjacent locations except as necessary for Project-related vegetation removal or wildlife relocation by a qualified biologist and subject to all applicable permits and authorizations. g. All open trenches or excavations shall be covered at the end of each workday to prevent wildlife entrapment. If an excavation is too large to cover, escape ramps shall be installed at an incline ratio of no greater than 2:1. All trenches and pipes shall be inspected for the presence of wildlife each day prior to the commencement of work. h. To enable San Joaquin kit foxes and other wildlife to pass through the Project site, any perimeter fencing shall include a 4- to 8-inch opening between the fence mesh and the ground or the fence shall be raised 4 inches above the ground except blunt-nosed leopard lizard exclusion fencing. The bottom of the fence fabric shall be knuckled (wrapped back to form a smooth edge) to protect wildlife. i. All vertical tubes used in Project construction and chain link fencing poles, shall be temporarily or permanently capped to avoid the entrapment and death of special-status wildlife and birds. All pipes 1.5 inches or greater in diameter stored overnight on a project location must have end caps or other physical barriers that prevent wildlife from entering the pipe. wildlife. j. All dead or injured special status wildlife shall be left in place and reported to the United States Fish and Wildlife Service and the California Department of Fish and Wildlife within 48 hours of discovery for rescue or salvage. Discovery of state or federal listed species that are injured or dead shall also be managed consistent with regulatory requirements, including being reported immediately via telephone and within 24 hours in writing, and with a copy to Kern County Planning and Natural Resources. k. All drilling installations and operations will comply at all times with the applicable federal, State, county, and local law ordinances and regulations. l. During pre-construction surveys, the qualified biologist shall delineate previously disturbed areas to be used by the applicant to minimize the amount of new disturbance. m. All concrete and asphalt debris should be removed from the site for recycling or disposal at an authorized, permitted facility. n. No vehicles or construction equipment shall be parked within a wetland or waterbody/dry wash. o. Tracked vehicles and other construction equipment must be washed or maintained to be weed-free prior to entering and working within areas of new disturbance.		

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		p. All washing of trucks, paint, equipment, or similar activities should occur in areas where runoff is fully contained for collection and offsite disposal. Wash water may not be discharged from the site and shall be located at least 100 feet from any water body, or sensitive Biological Resources. q. Locate all extra work areas (such as staging areas and additional spoil storage areas) at least 50 feet away from wetland boundaries or waterbody, except where the adjacent upland consists of cultivated or rotated cropland or other disturbed land. r. All areas that must be avoided as result of the pre-disturbance surveys, and areas where new disturbance will occur, shall be clearly delineated by fencing or staking and flagging and/or rope or cord. s. No firearms shall be allowed on any site. t. No pets shall be allowed on any site. u. No smoking may occur except in designated areas. v. If ground disturbance is intended to be temporary and does not occur on cultivated and crop lands, perform topsoil segregation during construction activities to preserve the seed bank for restoration efforts. Store the segregated topsoil separate from the subsoil and restore segregated topsoil to its original location. **MM 4.4-15** Ground disturbance shall be mitigated at a 1.0 to 1.0 ratio (one-acre of new disturbance shall require one-acre of mitigation) except in Tier 1 areas that contain existing disturbance of 70% or greater which shall be mitigated at a 1.0 to 0.5 ratio (one-acre of new disturbance shall require one-half acre of mitigation), for the land included in the Site Plan. This compensatory mitigation requirement does not apply to construction on ground for which compensatory mitigation has already been provided, or on ground that has been previously disturbed (e.g., cleared of vegetation for other oil and gas extraction uses, existing unpaved roads, and existing unvegetated well pads). Ground disturbance activities that are authorized by permits or other written authorizations approved by the United States Fish and Wildlife Service and the California Department of Fish and Wildlife, which include avoidance and compensatory mitigation acreage requirements, may be used to satisfy this County compensatory mitigation ratio. Compensatory mitigation shall be required for the actual acreage of ground disturbance documented during the site plan review and completion process. New disturbance mitigation may be satisfied by one or a combination of the following measures: a. The recordation of a conservation easement or similar permanent, long-term conservation management agreement in a form acceptable to the County for land within the Project Area on land that has mitigation value. The easement lands may be owned by an Applicant or a third party under contract with an Applicant. Larger land areas may be placed under a conservation easement or similar agreement, and an Applicant may "draw down" the conserved land as needed to satisfy the acreage mitigation requirements for multiple site plan review conformity permits or other authorizations from the County for oil and gas activities. b. Acquisition of land preservation credits from a mitigation bank located within the Project Area which is owned by the County, on other lands approved by the County, or on lands approved for mitigation or conservation purposes by the United States Fish and Wildlife Service or the California Department of Fish and Wildlife. c. Removal of legacy oil and gas equipment, inclusive of compliance with applicable legal requirements (e.g., well plugging and abandonment requirements under state or federal regulations), restoration of the surface grade to be consistent with surrounding lands, complete a reseeding effort using native species, and notification of the site owner (if not the Applicant) of the completion of the removal and grading restoration work. d. Enhancement or restoration of existing habitat on lands already subject to a conservation easement or similar agreement, or which become subject to a conservation easement or similar agreement subsequent to the certification of this Environmental Impact Report, provided that such activities are covered in a permit or authorization, conservation plan, Habitat Conservation Plan, or Natural Community Conservation Plan, approved by the United States Fish and Wildlife Service or the California Department of Fish and Wildlife. e. Payment of a biological resources mitigation fee for the acquisition and management of mitigation lands, legacy equipment removal, and/or land enhancement already subject to conservation easements or a similar agreements under the terms of any biological resource mitigation program that is adopted by Kern County and approved by the United States Fish and Wildlife Service or the California Department of Fish and Wildlife. The County shall coordinate with the United States Fish and Wildlife		

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		Service or the California Department of Fish and Wildlife to identify priority conservation areas and potential conservation partners and funding sources to increase the efficiency and effectiveness of mitigation fee expenditures.		
Impact 4.4-2 Have a Substantial Adverse Effect on Any Riparian Habitat or Other Sensitive Natural Community Identified in Local or Regional Plans, Policies, Regulations, or by the California Department of Fish and Wildlife or the United States Fish and Wildlife Service	Potentially significant	Implement **MM 4.4-1** through **4.4.15**, described above, and dust control, spill and hazardous material avoidance and containment, and surface and subsurface water quality and hydrology mitigation measures. **MM 4.4-16** Pre-disturbance surveys shall be conducted by a qualified biologist during the appropriate periods for detecting Sensitive Natural Communities that could occur within the Project Area. The surveys shall be completed consistent with applicable protocols approved by the United States Fish and Wildlife Service and/or the California Department of Fish and Wildlife, including the Protocols for Surveying and Evaluating Impacts to Special Status Native Plant Populations and Natural Communities (California Department of Fish and Wildlife 2009). The qualified person shall map and identify all sensitive natural communities, including riparian communities that occur in or within 100 feet of any new disturbance area. The site plan for the proposed activity shall identify waters, wetlands, resources subject to section 1600 of the CFGC, and other riparian habitats that occur in and within 100 feet of the disturbance area. **MM 4.4- 17** No land disturbance activity in any Sensitive Natural Community that requires a state or federal permit, including state or federally regulated wetlands and waters, shall occur unless the activity is specifically authorized by the issuance of permits or approvals as required by state and federal law. This provision is not intended to restrict survey activities or restrict permit approvals for such disturbance activities. However, no new wells, tanks, sumps or ponds shall be constructed within 50 feet of federal or state waters or wetlands.	Less than significant	All Tiers
Impact 4.4-3 Have a Substantial Adverse Effect on Federally Protected Wetlands as Defined by Section 404 of the Clean Water Act (Including, but Not Limited to, Marsh, Vernal Pool, Coastal, etc.) through Direct Removal, Filling, Hydrological Interruption, or Other Means	Potentially significant	Implementation of the Biological Resources mitigation measures would ensure that oil and gas activities would not disturb state or federally regulated wetlands and waters unless the activity is specifically authorized by the issuance of permits or approvals as required by state and federal laws and that activities in the vicinity of wetlands and water bodies would not adversely disturb them. Other mitigation measures identified in this Environmental Impact Report would further reduce potential state or federally jurisdictional wetland and waters, including dust control, spill and hazardous material avoidance and containment, surface and subsurface water quality and hydrology, mitigation measures.	Less than significant	All Tiers
Impact 4.4-4 Interfere Substantially with the Movement of any Native Resident or Migratory Fish or Wildlife Species, or with Established Native Resident or Migratory Wildlife Corridors, or Impede the Use of Native Wildlife Nursery Sites	Potentially significant	Implementation of the Biological Resources mitigation measures would reduce wildlife movement impacts. Other mitigation measures identified in this Environmental Impact Report to further reduce wildlife movement impacts, include dust control, nighttime lighting, noise controls, spill and hazardous material avoidance and containment,, and surface and subsurface water quality and hydrology (including but not limited to Kern River and Poso Creek channels), measures.	Less than significant	All Tiers
Impact 4.4-5 Conflict with Any Local Policies or Ordinances Protecting Biological Resources, Such as a Tree Preservation Policy or Ordinance	Potentially significant	**MM 4.4-1**8 In the event that new disturbance would occur at a site within an oak woodland area as defined in Section 1.10.10 of the Kern County General Plan Land Use, Open Space and Conservation Element (10% or greater oak tree cover), the Applicant shall comply with the minimum 30% canopy retention standard in Section 1.10.10 KK (a).	Less than significant	All Tiers
Impact 4.4-6 Conflict with the Provisions of an Adopted Habitat Conservation Plan, Natural Community Conservation Plan, or Other Approved Local, Regional, or State Habitat Conservation Plan	Potentially significant	**MM 4.4-19** Applicants shall fund through the Site Conformity Review administrative fee, preparation by Kern County of, an annual report describing the Project's ground disturbance acreage, and the acreage of compensatory mitigation lands, in each sub-area. For Covered Activities within areas included in proposed HCPs, the requirements of **MM 4.4-1 – 4.4-19** may be superseded by specific requirements imposed by USFWS as part of approval of a federal incidental take permit (e.g., under Section 10 or Section 7 of the Endangered Species Act), or by CDFW as part of approval of a state incidental take permit (e.g., under the Fish and Game Code), provided that USFWS (in the case of a federal incidental take permit) or CDFW (in the case of a state incidental take permit) concludes in writing that such requirements provide equivalent or greater protection than **MM 4.4-1 – 4.4-19** (or any subset thereof).	Less than significant	All Tiers

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Impact 4.4-7 Cumulative Impact to Biological Resources	Potentially significant	Implement **MM 4.4-1** through **MM 4.4-19**, as described above.	Significant and unavoidable	All Tiers
Cultural Resources				
Impact 4.5-1 Cause a Substantial Adverse Change in the Significance of a Historical Resource as Defined in Section 15064.5	Potentially significant	**MM 4.5-1** Prior to initiating ground disturbance activities for an activity for which a conformity review is required, the Applicant shall: a. Provide an archival records search completed by a qualified archaeologist. This shall include an examination of the California Historical Resources Information Files at the Southern San Joaquin Valley Information Center, California State University, Bakersfield, and a search of the Native American Heritage Commission Sacred Lands Files, Sacramento. The Applicant may rely on a previously performed records search for subsequent ground disturbing activities. b. If an application location has been previously surveyed and no cultural resources have been recorded on it, no further cultural resources studies shall be required. c. Implement either: 1. If a site plan includes land that has experienced 100% previous ground-surface disturbance, or is within a section with 300 or more existing oil wells or other agricultural, industrial or urban uses, and the records searches indicate that no cultural or Native American resources are known on it, no further cultural resources studies shall be required. All other application locations shall be subject to intensive (100%) pedestrian ground-surface survey (phase I survey/Class III inventory) by qualified archaeologists. The Applicant may rely on a previously performed ground surface survey for subsequent ground disturbing activities; or 2. If an application location has not been previously surveyed based on the records search information, an intensive (100%) pedestrian ground-surface survey (Phase I survey/Class III inventory) by qualified archaeologists shall be required. d. All prehistoric/Native American archaeological sites, whether identified during the records searches or during the intensive survey, shall be demarcated by a qualified archaeologist, fenced by the Applicant, and preserved in place. e. Historical (Euro-American) archaeological sites that are potentially eligible for listing in the National Register of Historic Places shall be evaluated by a qualified archaeologist and must meet the requirements of the National Historic Preservation Act of 1966 in order to qualify. Qualifying sites, structures and equipment that are identified during the records search or field survey shall be fenced and preserved in open-space, removed and curated, or treated using data recovery procedures that follow the guidelines of the Secretary of the Interiors Standards for Architectural and Engineering Documentation. f. Historical (Euro-American) archaeological site types relating to oil and gas activities that have been determined Not Significant/Unique shall require no archaeological study or treatment. g. All oil and gas industry employees conducting work in the area identified on the Conformity Site Plan shall complete Worker Environmental Awareness Program training including training dedicated to cultural resources protection.	Less than significant	All Tiers
Impact 4.5-2 Cause a Substantial Adverse Change in the Significance of an Archaeological Resource as Defined in Section 15064.5	Potentially significant	Implement **MM 4.5-1**, as described above.	Less than significant	All Tiers

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Impact 4.5-3 Directly or Indirectly Destroy a Unique Paleontological Resource or Site or Unique Geologic Feature	Potentially significant	**MM 4.5 -2** As part of any Worker Environmental Awareness Program training, all construction personnel shall be trained regarding the recognition of possible buried paleontological resources and protection of paleontological resources during construction, prior to the initiation of construction or ground-disturbing activities. Training shall inform construction personnel of the procedures to be followed upon the discovery of paleontological materials. All personnel shall be instructed that unauthorized collection or disturbance of fossils is unlawful. **MM 4.5 -3** All permits for new wells that use Enhanced Oil Recovery or Well Stimulation methods shall pay a mitigation fee of $50 per well shall be paid to the Buena Vista Museum to fund the continued education and curation of paleontological resources and provide educational support regarding the paleontological history of the region.	Less than significant	All Tiers
Impact 4.5-4 Disturb any Human Remains, Including Those Interred Outside of Formal Cemeteries	Potentially significant	**MM 4.5-4** In the event archaeological materials are encountered during the course of ground disturbance or construction, the Project operator/contractor shall cease any ground disturbing activities within 50 feet of the find. The qualified archaeologist shall evaluate the significance of the resources and recommend treatment measures. Per California Environmental Quality Act Guidelines Section 15126.4(b)(3), Project redesign and preservation in place shall be the preferred means to avoid impacts to significant historical resources. Consistent with California Environmental Quality Act Guidelines Section 15126.4(b)(3)(C), if it is demonstrated that resources cannot be avoided, the qualified archaeologist shall develop additional treatment measures in consultation with the County, which may include data recovery or other measures. The Planning and Natural Resources Department shall consult with Native American representatives in determining treatment for unearthed cultural resources if the resources are prehistoric or Native American in nature. If after consultation it is determined that archaeological materials are to be recovered then they shall be curated at an accredited curation facility. The qualified archaeologist shall prepare a report documenting evaluation and/or additional treatment of the resource. A copy of the report shall be provided to the Kern County Planning and Natural Resources Department and to the Southern San Joaquin Valley Information Center. In the event archaeological materials are encountered, in Tier 2 the surface owner shall be notified immediately. **MM 4.5-5** If human remains are uncovered during Project construction, the Applicant shall immediately halt all work, contact the Kern County Coroner to evaluate the remains, and follow the procedures and protocols set forth in Section 15064.5 (e)(1) of the California Environmental Quality Act Guidelines. The Kern County Planning and Natural Resources Department shall be notified concurrently. If the County Coroner determines that the remains are Native American, the Project proponent shall contact the Native American Heritage Commission, in accordance with Health and Safety Code Section 7050.5, subdivision (c), and Public Resources Code 5097.98 (as amended by Assembly Bill 2641). The Native American Heritage Commission shall designate a Most Likely Descendant for the remains per Public Resources Code 5097.98. Per Public Resources Code 5097.98, the applicant, in coordination with the landowner, shall ensure that the immediate vicinity, according to generally accepted cultural or archaeological standards or practices, where the Native American human remains are located, is not damaged or disturbed by further development activity until the discussion and conference with the Most Likely Descendant has occurred, if applicable, taking into account the possibility of multiple human remains. If the remains are determined to be neither of forensic value to the Coroner, nor of Native American origin, provisions of the California Health and Safety Code (7100 et. seq.) directing identification of the next-of-kin will apply. In the event human remains are uncovered, in Tier 2 the surface owner shall be notified immediately.	Less than significant	All Tiers
Impact 4.5-5 Cumulative Impacts to Historical, Archaeological, or Paleontological Resources and Human Remains	Potentially significant	Implement **MM 4.5-1** through **MM 4.5-5**, as described above.	Significant and unavoidable	
Geology and Soils				
Impact 4.6-1 Expose People or Structures to Substantial Adverse Effects, Including the Risk of Loss, Injury, or Death Involving the Rupture of a Known Earthquake Fault	Potentially significant	**MM 4.6-1** Prior to beginning a ground disturbance activity, the Applicant shall comply with the following regulations (as applicable) and confirm compliance in its Site Plan Conformity Review application documentation: a. Alquist-Priolo Earthquake Fault Zoning Act. b. California Building Code.	Less than significant	All Tiers

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		c. California Geologic Energy Management Division regulations, as identified in the California Code of Regulations, Title 14, Division 2, Chapter 4, including regulations implementing Senate Bill 4 as applicable. If hydraulic fracturing is conducted for any well associated with the Site Plan Conformity Review, the Applicant shall comply with requirements to monitor the California Integrated Seismic Network for indication of an earthquake of magnitude 2.7 or greater for the period of 10 days following the end of hydraulic fracturing. The earthquake search radius shall be consistent with Geologic Energy Management Division Senate Bill 4 regulations. The data will be submitted to Geologic Energy Management Division for an evaluation of the risks and actions consistent with Geologic Energy Management Division Senate Bill 4 regulations. In approving a well stimulation treatment permit that would authorize, within an urban area (i.e., an area with a population over 50,000, as defined by the U.S. Census Bureau), the emplacement of well stimulation fluids into an oil or gas formation that has not been previously been subject to well stimulation activity, and/or into an oil or gas formation for which the Geologic Energy Management Division does not yet possess adequate information about formation fracture geometries, the Geologic Energy Management Division shall impose a permit condition requiring that the applicant conduct ground monitoring to characterize as built fracture geometries prior to, during, and post-hydraulic fracturing. Monitoring shall also be conducted during fracturing treatments by use of applicable microseismic fracture mapping, tilt measurements, tracers, or proppant tagging. Copies of ground monitoring records shall be provided to the County and Geologic Energy Management Division for review and approval within 30 days of well stimulation treatment. d. Additionally, the Applicant shall: 1. Avoid placement of structures intended for human occupancy on or within 50 feet of any active faults designated and mapped pursuant to the Alquist-Priolo Earthquake Fault Zoning Act where the fault breaks the surface. 2. Have a professional geologist prepare a fault rupture hazard evaluation according to guidelines in California Geological Survey Special Publication 42, 2007 for new developments with structures that are intended for human occupancy. 3. All Class II injection wells shall be authorized, and shall comply with all applicable legal requirements, Underground Injection Control Program Approval permit conditions, and be operated according to the California Code of Regulations Title 14 requirements, as described in the mitigation measures for Hydrology and Water Quality. 4. Ensure that active fault trace placement restrictions are in place for all permanent tanks and storage reservoirs used to store, treat, or transport hazardous materials or materials that are considered pollutants to surface water and groundwater, located in an Earthquake Fault Zone. Ensure that all newly installed pipelines subject to 49 Code of Federal Regulations (CFR) Parts 192 and 195, are engineered and constructed in compliance with the requirements of the pipeline safety regulations, as set forth by the Pipeline Hazardous Materials Safety Administration (PHMSA). All other newly installed pipelines that transport gas or hazardous liquids are to be constructed, tested operated and maintained in accordance with good oilfield practice and applicable standards set forth and approved by the State Oil and Gas Supervisor. Ensure that all new pipelines designated for or water used for fire suppression are engineered and constructed in compliance with the requirements of California Building Code Chapter 9, Fire Protection Systems, and the California Fire Code to address potential fault rupture displacements. **MM 4.6-2** All structures designed for human occupancy shall be designed to withstand substantial ground shaking in accordance with applicable California Building Code seismic design standards and Kern County Building Code.		
Impact 4.6-2 Expose People or Structures to Substantial Adverse Effects, Including the Risk of Loss, Injury, or Death Involving Strong Seismic Ground Shaking	Potentially significant	Implement **MM 4.6-1** and **MM 4.6-2**, as described above.	Less than significant	All Tiers

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Impact 4.6-3 Expose People or Structures to Substantial Adverse Effects, Including the Risk of Loss, Injury, or Death Involving Seismic-Related Ground Failure, Including Liquefaction	Potentially significant	Implement **MM 4.6-1** and **MM 4.6-2**, as described above.	Less than significant	All Tiers
Impact 4.6-4 Expose People or Structures to Substantial Adverse Effects, Including the Risk of Loss, Injury, or Death Involving Landslides	Potentially significant	**MM 4.6-3** Operators shall avoid siting wells or accessory equipment and facilities on slopes greater than 30%, unless the applicant provides written evidence that they are unable to obtain a mineral lease provides written evidence that the applicant is unable to obtain a mineral lease for a location that is less than 30% slope or professional engineering certification that they cannot slant drill from a location that is less than 30% slope. If the applicant provides such written evidence, then a site specific geotechnical report certified by a licensed engineering professional shall be submitted in conjunction with any permit detailing the work needed on the slope to construct and operate in full compliance with general engineering practices to ensure slope stability and protections for downslope properties. The site specific engineering certification and recommendations shall be submitted and reviewed by the Kern County Public Works Department and no permit shall be issued until the Kern County Public Works department provides an engineering approval of the recommendations to protect life and property. All recommendations required by the approved engineering certification from Kern County Public Works shall be implemented. Any requests for deviations from the approved certification will require the processing of a Conditional Use Permit as a discretionary action.	Less than significant	All Tiers
Impact 4.6-5 Result in Substantial Soil Erosion or the Loss of Topsoil	Potentially significant	Implement stormwater mitigation measures, as described in Section 4.9, Hydrology and Water Quality.	Less than significant	All Tiers
Impact 4.6-6 Be Located on a Geological Unit or Soil That is Unstable, or That Would Become Unstable as a Result of the Project, and Potentially Result in On- or Off-site Landslide, Lateral Spreading, Subsidence, Liquefaction, or Collapse	Potentially significant	Implement **MM 4.6-3**, as described above, and the following: **MM 4.6-4** The Applicant shall confirm compliance with, and shall implement, a Geologic Energy Management Division approved re-pressuring plan as required by Division 3, Chapter 1, Article 5.5 of the Public Resources Code, commencing with Section 3315. In developed areas where subsidence is confirmed or suspected, subsidence monitoring shall be required using Synthetic Aperture Radar studies and/or other methods as approved by the Geologic Energy Management Division to quantify and evaluate the potential effect on the area.	Less than significant	All Tiers
Impact 4.6-7 Be Located on Expansive Soil, as Defined in Table 18-1-B of the Uniform Building Code (1994), Creating Substantial Risks to Life or Property	Potentially significant	**MM 4.6-5** The ~~Applicants~~ Applicant shall avoid building infrastructure on expansive soil, unless the Applicant determines that mineral recovery is infeasible from a different location, and site-specific Professional Engineering certification is submitted concluding that the new equipment will not cause substantial risks to life or property. The site specific professional engineering certification must be submitted, and reviewed by the Kern County Public Works Department and a memo provided that agrees that construction and operation of new equipment will not cause substantial risks to life or property as determined through established engineering standards. All recommendations required by the approved engineering certification from Kern County Public Works shall be implemented.	Less than significant	All Tiers
Impact 4.6-8 Have Soils Incapable of Adequately Supporting the Use of Septic Tanks or Alternative Wastewater Disposal Systems Where Sewers Are Not Available for the Disposal of Wastewater	Less than significant	Implement **MM 4.6-1**, as described above.	Less than significant	All Tiers

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Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Impact 4.6-9 Cumulative Impacts to Geologic and Soil Resources	Potentially significant	Implement **MM 4.6-1** through **MM 4.6-5**, as described above.	Less than significant	All Tiers
Green House Gas Emissions				
Impact 4.7-1 Generate Greenhouse Gas Emissions, Either Directly Or Indirectly, that may have a Significant Impact on the Environment	Potentially significant	**MM 4.7.1** An Applicant covered by the Cap-and-Trade Program with permitted stationary sources shall comply with the Cap-and-Trade regulation (especially by surrendering greenhouse gas allowances or offset credits to satisfy their compliance obligation under the Program), and implement Best Performance Standards applicable to greenhouse gas reduction for Components at Light Crude Oil and Natural Gas Production, Natural Gas Processing Facilities, Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants (San Joaquin Valley Air Pollution Control District 2010), Thermally Enhanced Oil Recovery Wells (San Joaquin Valley Air Pollution Control District 2010a), Steam Generators (San Joaquin Valley Air Pollution Control District 2010b), and Front-line Organic Liquid Storage Tanks (San Joaquin Valley Air Pollution Control District 2011). **MM 4.7.2** Each Applicant covered by the Cap-and-Trade Program shall comply with applicable Cap and Trade regulations, and other applicable greenhouse gas emission control and reduction regulations as these may be adopted or amended over time, to reduce, avoid, mitigate and/or sequester greenhouse gas emissions from Project-related air emissions. **MM 4.7-3** Each Applicant shall implement methods to recover for reuse or destroy methane existing in associated gas and casinghead gas, as follows: a. Recover all associated gas produced from the reservoir via new wells, regardless of the well type, except for gas produced from wildcat and delineation wells or as a result of start-up, shutdown and maintenance activities (whether planned or unplanned), system failures, and emergencies in accordance with San Joaquin Valley Air Pollution Control District regulations (Rule 4401 and 4409), as this may be amended over time. b. Compliance with the expected California Air Resources Board methane regulation. **MM 4.7-4** Each Applicant shall offset all greenhouse gas emissions not covered by the Cap-and-Trade program or other mandatory greenhouse gas emission reduction measures through Applicant reductions of greenhouse gas emissions as verified by Kern County, through acquisition of offset credits from the California Air Pollution Control Officers Association Exchange Register or other third party greenhouse gas reductions, with consultation as to the validity of methodology for calculating reductions verified by the San Joaquin Valley Air Pollution Control District and accepted by Kern County, or through inclusion in an Emission Reduction Agreement, to offset Project-related greenhouse gas emissions that are not included in the Cap and Trade program to assure that no net increase in greenhouse gas emissions from the Project.	Less than significant	All Tiers
Impact 4.7-2 Conflict with any Applicable Plan, Policy, or Regulation Adopted for the Purpose of Reducing the Emissions of Greenhouse Gases	Potentially significant	Implement **MM 4.7-3**, as described above.	Significant and unavoidable	All Tiers
Impact 4.7-3 Cumulative Greenhouse Gas Emissions Impacts	Potentially significant	Implement **MM 4.7-4**, as described above.	Significant and unavoidable	All Tiers
Hazards and Hazardous Materials				
Impact 4.8-1	Potentially significant	**MM 4.8-1** The Applicant shall provide a comprehensive Worker Environmental Awareness Program to the County with its first Site Plan Conformity Review permit application in each calendar year. The program shall include all training requirements identified in Applicant Best Management Practices and mitigation measures, and include training for all field personnel (including Applicant employees, agents and contractors). The Worker Environmental Awareness Program shall include protocols and training for responding to and handling of	Less than significant	All Tiers

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Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Create a Significant Hazard to the Public or the Environment through the Routine Transport, Use, or Disposal of Hazardous Materials		hazardous materials and hazardous waste management, and emergency preparedness, release reporting, and response requirements. In Tier 2, the Worker Environmental Awareness Program shall be provided to the surface owner at the time of the application pathway process so the surface owner may educate employees as well. **MM 4.8-2** The Applicant shall arrange for transportation, storage and disposal of all hazardous materials in compliance with the Hazardous Materials Transportation Act. Drivers transporting hazardous materials or wastes should follow the measures recommended by the Federal Motor Carrier Safety Administration for avoiding roll-over accidents which include the following standards for cargo tank trucks: a. Avoid sudden movements that may lead to roll-overs. b. Maintain control of the load in turns and on straight roadways. c. Identify in advance of transport high risk areas on designated roads. d. Follow driver mandates for being alert and attentive behind the wheel. e. Control speed and maintain proper "speed cushions" described by the Federal Motor Carrier Safety Administration. **MM 4.8-3** The Applicant shall implement the following practices based on practices and standards established by the United States Department of Labor Occupational Safety and Health Administration (OSHA) safety standards and as amended or modified by the State of California Department of Industrial Relations, Division of Occupational Safety and Health (DOSH – Cal/OSHA) and the Kern County Fire Department. a. Construction activities shall be conducted to allow for easy clean-up of spills. Construction crews shall have the appropriate number of tools, supplies, and absorbent and barrier materials to contain and recover spilled materials. b. Fuels and lubricants shall be stored only at designated staging areas. Fuel and lubricant tanks shall have secondary spill containment (e.g., curbs). Compliance with laws and regulations is required, including compliance with hazardous materials and hazardous waste storage laws, as applicable. c. Storage of fuel and lubricants in the staging area shall be at least 100 feet away from the edge of water bodies. Refueling and lubrication of equipment shall be restricted to upland areas at least 100 feet away from stream channels and wetlands. d. Any fuel truck shall carry an oil spill response kit and spill response equipment at all times. e. Applicants shall be required to perform all routine equipment maintenance at the well pad or other suitable locations (i.e., maintenance yards), and promptly collect and lawfully dispose of wastes in compliance with existing regulatory requirements. f. Berms and/or dikes (secondary containment) shall be constructed around the permanent above-ground bulk tanks and the foundations shall be installed with a passive leak detection system, so that potential spill materials shall be contained and collected in specified areas isolated from any water bodies. Tanks shall not be placed in areas subject to periodic flooding or washout. Compliance with laws and regulations is required, including compliance with hazardous materials and hazardous waste storage laws as applicable, including for secondary containment, such as Geologic Energy Management Division regulation (Title 14, C.C.R. § 1773.1), which requires secondary containment in "an engineered impoundment such as a catch basin, which can include natural topographic features, that is designed to capture fluid released from a production facility." g. The appropriate amount and supply of sorbent and barrier materials shall be maintained on construction sites consistent with the type and level of construction activities. Sorbent and barrier materials shall also be utilized to contain runoff from contaminated areas consistent with CalOSHA regulations. h. Shovels and drums shall be stored at each well pad or be readily available. If small quantities of soil become contaminated, hand tools shall be used to collect the soil and the material shall be stored in storage drums. Large quantities of contaminated soil may be bio-remediated on-site or at a designated remediation facility, subject to government approval, or collected utilizing heavy equipment, and stored in drums or other suitable containers prior to disposal. Should contamination occur adjacent to staging areas as a result of runoff, shovels and/or heavy equipment shall be utilized to collect the contaminated material. Contaminated soil shall be disposed of in accordance with state and federal regulations.		

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		i. Above-ground tanks, valves and other equipment shall be visually inspected monthly and when the tank is refilled. Inspection records shall be maintained. Applicants shall periodically check tanks for leaks or spills. j. Drain valves on all tanks shall be locked to prevent accidental or unauthorized discharges from the tank. k. Equipment maintenance shall be conducted in staging areas or other suitable locations (i.e., maintenance shops or yards). l. The Applicant shall maintain equipment in operating condition to reduce the likelihood of fuel or oil line breaks and leakage. Any vehicles with chronic or continuous leaks shall be removed from the site and repaired before being returned to operation. **MM 4.8-4** The Applicant shall implement the following measures to prevent, repair, and remediate accidental leaks and spills from oil and gas operations. a. The Applicant shall identify gas, oil and produced water pipelines to be used for each new or reworked well site in its Site Plan, and shall show the location of any sensitive receptor located within 300 feet of any such pipeline. For any pipeline located within 300 feet of a sensitive receptor, the Applicant shall present evidence that each such pipeline has been integrity tested using pressure testing or other accepted test methods by a qualified professional within a two-year period prior to submittal of the Site Plan, and shall provide a copy of the test result to the County. For all waste gas lines less than or equal to 4 inches in diameter, a Pipeline Management Plan shall be developed and implemented in accordance with California Geologic Energy Management Division regulations Title 14, Division 2, Chapter 4, Section 1774.2. The Pipeline Management Plan shall include: 1. A listing of information on each pipeline including, but not limited to: i. Pipeline type. ii. Grade. iii. Installation date of pipeline. iv. Design and operational pressure. v. Any leak, repair, inspection and testing history. 2. A description of the testing method and schedule for all pipelines. b. The Applicant shall notify the Kern County Public Health Services Environmental Health Division, Certified Union Program Agency (CUPA), surface landowner, and sensitive receptors located within 300 feet, of any hazardous materials/waste release immediately upon discovery, and to other applicable agencies as required by other laws. The Applicant shall immediately contain the leak (e.g., by isolating or shutting down the leaking equipment), clean up contaminated media (e.g., soils), and repair the leak prior to recommencing operations. The Applicant shall report the status and progress of the leak repair and remediation work to the County and the CUPA on monthly intervals or predetermined intervals until the repair has been completed. Contaminated media shall be analyzed according to 22 C.C.R. §§ 66261.21-66261.24 for determination of hazardous waste disposal subject to the Hazardous Waste Determination procedures provided in 22 C.C.R. §66262.11. c. As part of the Site Plan, the Applicant shall identify the location and right of way for all pipelines to be used for the transport of oil, gas, and produced water, including pipelines that intersect the main transport line, based on existing data and using commercially available technology, and, based on the results of this analysis, shall identify any sensitive receptors within 300 feet of the pipeline for purposes of complying with Mitigation Measure 4.8-4. Mechanical integrity testing of all such pipeline lengths within 300 feet of a sensitive receptor shall be required pursuant to Mitigation Measure 4.8.4-a. **MM 4.8-5** If, during grading or excavation work, the Applicant observes evidence of contamination or if soil contamination is suspected, work near the excavation site shall be terminated, the work area cordoned off and required health and safety procedures implemented for the location by the contractor's Health and Safety Officer. Samples shall be collected by a trained and qualified individual. Analytical data from suspected contaminated material shall be reviewed by the contractor's Health and Safety Officer. If the sample testing determines that contamination is not present, work may proceed at the site; however, if contamination is detected above regulatory limits, the Kern County Public Health Services Department shall be notified. All actions related to encountering unanticipated hazardous materials at the site shall be documented and submitted to the Kern County Public Health Services Department for legal direction from the regulatory agency. **MM 4.8-6** The Applicant shall implement measures to prevent the release or accidental spillage of solid waste, garbage, construction debris, sanitary waste, industrial waste, naturally occurring radioactive materials, oil and other petroleum products, and other wastes into water bodies or water sources, including all applicable practices included in the most up-to-date versions of the following documents: Exemption of Oil and Gas Exploration and Production Wastes From Federal Hazardous Waste Regulations (EPA 2002). Equivalent industry standards such as Environmental Protection for Onshore Oil and Gas Productions and Leases (American Petroleum Institute 2009) and related standards may also be utilized, provided that a professional engineer, certified industrial hygienist or certified safety professional certifies to the		

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		County that such standards are as or more protective of human health and the environment, as compared to the standards in the referenced Environmental Protection Agency manual. The following are practices and standards that shall be implemented. a. Classify the various oil and gas exploration and production wastes for disposal as described in United States Environmental Protection Agency 2002, and in accordance with applicable California laws and regulations. b. Size reserve pits to avoid overflows. c. Use closed loop mud systems with oil-based muds except in compliance with State Water Resources Board or Regional Water Quality Control Board requirements as provided in Mitigation Measure 4.9-3. d. Review safety data sheets of materials used, and use the less toxic material for the operation. e. Design systems with the smallest volumes possible (e.g., drilling mud systems). f. Reduce the amount of excess fluids entering reserve and production pits. g. Keep non-exempt wastes out of reserve or production pits. h. Design the drilling pad to contain stormwater and rigwash. i. Recycle and reuse oil-based muds and high density brines, when such recycling and reuse complies with hazardous waste laws and recycling laws. j. Perform routine equipment inspections and maintenance to prevent leaks or emissions. k. Reclaim oily debris and tank bottoms when such reclamation complies with hazardous waste laws and recycling laws. l. Store only the volume of materials at facilities necessary for permitted work. m. Construct berms around materials and waste storage areas that meet engineering standards to contain spills. n. Perform routine inspections of materials and waste storage areas to locate damaged or leaking containers. o. Train personnel in all waste management practices required by the mitigation measures, all legal standards and the permits issued by Kern County, CalGEM and all regulatory agencies. **MM 4.8-7** The following specific measures should be implemented at a minimum when conducting exploration and development activities: a. Impervious secondary containment, such as containment dikes, containment walls, and drip pans shall be constructed and maintained around all qualifying petroleum facilities, including tank batteries and separation and treating areas consistent with the Environmental Protection Agency's Spill Prevention, Control, and Countermeasures regulation (40 Code of Federal Regulations 112). The containment structure must have sufficient volume to contain, at a minimum, the content of the largest storage tank containing liquid hydrocarbons within the facility/battery and engineered freeboard to contain precipitation. Drip pans shall be routinely checked and cleaned of petroleum or chemical discharges and designed to prevent access by wildlife and livestock.as determined by the qualified biologist. b. Chemical containers shall not be stored on bare ground, and shall be maintained in good condition and shall be placed within secondary containment in case of a spill or high velocity puncture. c. Containment dikes are not to be constructed with topsoil or coarse, insufficiently impervious spoil material that is insufficiently impervious to meet requirements. Containment is strongly suggested for produced water tanks. Chemicals shall be placed within secondary containment and stored so that the containers are not in contact with soil or standing water and product and hazard labels are not exposed to weathering. d. Maintain a clean well location. Remove trash, junk, and other materials not in current use. e. In approving a well stimulation treatment permit, the applicant shall include in the spill contingency plan prepared by a qualified professional as required by Section 1722.9 of Title 14 of the California Code of Regulations a protocol for measuring and reporting earthquake and earth consequences that occur during the well stimulation process, for the total number of well stimulation		

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		treatments are proposed to occur simultaneously at any given time. The Spill Contingency Plan shall include requirements for levels of personnel and equipment to respond to damage that could occur and that will be necessary to conduct post-earthquake inspection and repair plans to address any damage that has occurred. The Spill Contingency Plan shall include spill prevention, control and countermeasure plans to address the hazardous substances associated with well stimulation activities. The post-earthquake inspection procedures shall ensure the integrity of the mechanical systems and well integrity of wells used for stimulation or wastewater injection and idle wells that might have become conduits for escaping fluids or gases. The plan shall include procedures describing the necessary steps to be taken after service is disrupted in order to make the facilities secure, operational and safe as soon as possible **MM. 4.8-8** Applicants shall use the accepted engineering standards for California oil operations recognized as safe and effective by CalGEM and other state and local regulatory agencies including American Petroleum Institute Standards, or other recognized sources imposing the same or equivalent standards, for their facility, operations and permitting such as the following: a. Use cements and well materials in well completions as described in Specifications for Cements and Materials for Well Cementing (American Petroleum Institute 2011). b. Prior to start-up of all new facilities, verify and· prove the construction, installation, integration, testing, and preparation of systems have been completed as designed following the practices described in Facilities Systems Completion Planning and Execution (American Petroleum Institute 2013a). c. When the use of centralizers and stop-collars are required during well completion activities, follow the installation and testing requirements described in Recommended Practice for Centralizer Placement and Stop-collar Testing (American Petroleum Institute 2010a). d. Limit the environmental footprint of oil and gas exploration and production and reduce the incidence of releases of hazardous substances by complying with the practices described in Environmental Protection for Onshore Oil and Gas Production Operations and Leases (American Petroleum Institute 2009). e. Eliminate improper disposal by complying with the practices described in American Petroleum Institute Order No. G00004, Guidelines for Commercial Exploration and Production Waste Management Facilities (American Petroleum Institute 2001) or other legal methods. All disposal must follow applicable laws, regulations, and receiving facilities permit requirements. f. Limit the environmental footprint of exploration and production activities by complying with the practices described in Land Drilling Practices for Protection of the Environment (American Petroleum Institute 2010b) or other engineering guidance documents as accepted by CalGEM. g. When pressure testing is required by State or federal law, prior to pressurizing or re-pressurizing petroleum product pipelines, ensure the integrity of pipelines by complying with the practices described in Recommended Practice for the Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide (American Petroleum Institute 20 13b) or other engineering guidance documents as accepted by CalGEM. h. To prevent releases of hazardous substances during oilfield construction, all pit and sump operations shall be conducted in accordance with State Water Resources Control Board General Orders or Regional Water Quality Control Board waste discharge requirements or general orders or other legal requirements applicable to oil and gas exploration, extraction and well stimulation activities. **MM 4.8-9** For all operations subject to the Oil and Gas Conformity Review, the Applicant shall comply with the pipeline management plan, including inspection and maintenance requirements, as administered by the Geologic Energy Management Division pursuant to 14 California Code of Regulations 1774.		
Impact 4.8-2 Create a Significant Hazard to the Public or the Environment through Reasonably Foreseeable Upset and Accident Conditions Involving the Release of Hazardous Materials into the Environment	Potentially significant	Implement **MM 4.8-1** through **MM 4.8-9**, as described above, and **MM 4.8-10** The Applicant shall incorporate annual maintenance checks for leaks and corrosion that cause releases into current operations, maintenance, and inspection schedules as provided by the Geologic Energy Management Division pursuant to 14 California Code of Regulations Sections 1774.1 and 1774.2, the Applicant shall visually inspect all above-ground pipelines for leaks and corrosion at least once per year, comply with the pipeline testing requirements included therein, shall maintain records of such inspections and testing; and shall make inspection and testing records available to the County for review upon request.	Less than significant	All Tiers

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
		MM 4.8-11 As part of the Hazardous Materials Business Plan and the spill prevention, control, and Countermeasures Plan, the Applicant shall require annual worker training requirements to: increase awareness of the most common types of failures and methods to avoid mistakes, shall maintain records of employee training, and shall make such records available to the County for review upon request. **MM 4.8-12** An Applicant who plans to perform cyclic steam injection activities above reservoir fracture pressures shall conduct such activities in accordance with the requirements set forth in the Geologic Energy Management Division site-specific Project Approval Letter for the injection project. The following requirements from a Project Approval Letter for an injection project are examples of the types of conditions that would be triggered if a surface expression were to occur, though such conditions may be modified by the Geologic Energy Management Division to reflect site-specific conditions and changing regulatory requirements. a. Cease cyclic steaming operations in accordance with the site-specific Project Approval Letter. Streaming can resume following the Geologic Energy Management Division specifications outlined in the Project Approval Letter. b. All new or reactivated surface expressions that discharge oil in a reportable quantity shall be reported as an oil spill to the California Emergency Management Agency at (800) 852-7550. c. Any measures to address surface expressions from the well and associated Project shall be reviewed by the Geologic Energy Management Division prior to initiating. d. Immediately control any water, steam, or oil flowing from a surface expression and contained. All discharged material shall be removed and disposed of in a manner approved by all state and local agencies. e. Cordon off and clearly mark all surface expressions to prevent inadvertent access. f. Conduct air sampling of any emissions associated to a recent surface expression in accordance to the local air board requirements to ensure a health hazard condition does not exist. g. Report immediately to the Geologic Energy Management Division all surface expressions within 300 feet of the Project site. If the surface expression continues to flow after five days, all wells within a 300-foot radius shall cease steaming until the surface expression ceases to flow. If the surface expression continues to flow, the damage will be evaluated at the Supervisor's discretion, as assigned by Section 3106 of the Public Resources Code and existing laws and regulations. **MM 4.8-13** The Applicant shall comply with the Geologic Energy Management Division requirements for assuring safe drilling and drill casing practices, well design, construction and well management requirements, blowout requirements, and all other provisions of 14 California Code of Regulations 1744 and other applicable Geologic Energy Management Division_regulations. The Applicant shall also reduce the incidence of well control loss by following the practices described in Recommended Practice for Well Control Operations (American Petroleum Institute 2012). **MM 4. 8-14** The Applicant shall report contamination caused by oil and gas activities, including previously unknown injection wells, of a reportable quantity of hazardous substances, as specified in the Code of Federal Regulations Title 40 and/or the California Code of Regulations Titles 22 and 23, which is discovered during Project construction activities and operations. Notification must be made within 24 hours of discovery to Kern County Public Health Environmental Health Division, Kern County Planning and Natural Resources Department and all State and Federal implementing regulatory agencies that have responsibility or oversight of the specific contamination conditions and activity. The Applicant shall remediate such contamination outside Tier 1 areas as required by the Kern County Environmental Health Division and the appropriate implementing regulatory agency.		

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Impact 4.8-3 Emit Hazardous Emissions or Handle Hazardous or Acutely Hazardous Materials, Substances, or Waste within One-Quarter Mile of an Existing or Proposed School	Potentially significant	Implement toxic air contaminant setback mitigation measures, as described in Section 4.3, Air Quality, and **MM 4.8-15** The Applicant who intends to use acutely hazardous chemicals, including chemicals at or above the specified threshold quantities or a process which involves a Category 1 flammable gas or a flammable liquid with a flashpoint below 100 degrees Fahrenheit (37.8 degrees Celsius) on site in one location, in a quantity of 10,000 pounds (4535.9 kilograms) or more according to 8 California Code of Regulations Section 5189, Appendix A, within 0.25 mile from a school must prepare a Spill Prevention, Control, and Countermeasures Plan which includes details of the following measures as well as those contained in the regulations : a. Evaluate whether other alternative chemicals that are less hazardous could be used and provide an explanation on why other less hazardous chemicals cannot be used. b. Include specific details on the smallest quantity of necessary acutely hazardous materials that are needed for the specific activity and that will be stored on site. c. Notify the occupants of the school buildings when and where acutely hazardous materials would be used. d. Notify Kern County Fire Department about the details of the use of acutely hazardous materials (e.g., when, where, how much). e. Ensure that all employees who would contact the acutely hazardous materials are trained on the handling, transport, storage, and disposal of the materials. f. Ensure that all employees who would contact the acutely hazardous materials are trained and are provided the OSHA mandated personal protective equipment. g. Ensure that all employees who would contact the acutely hazardous materials are trained and have exercised on the Spill Prevention, Control, and Countermeasures Plan that addresses these chemicals. **MM 4.8-16** The applicant shall not use any well stimulation fluid unless the applicant presents one of the following: 1. Safety Data Sheet that accurately describes the physical and chemical properties of the well stimulation fluid; or 2. Safety Data Sheets that accurately describe the physical and chemical properties of all chemical compounds in the well stimulation fluid; or 3. Toxicological report prepared by a qualified laboratory and/or the fluid vendor confirming the environmental profile of the well stimulation fluid is known; or 4. Results of an aquatic bioassay by a qualified laboratory confirming the environmental profile of the well stimulation fluid is known. For purposes of this mitigation measure, the term “environmental profile” means the physical and chemical properties of a compound that determine its risk to human health and the environment. This mitigation measure shall be superseded by any list of approved well stimulation treatment fluids, chemicals or additives published by the State of California or by any applicable State of California regulation pertaining to chemical use in well stimulation treatment.	Less than significant	All Tiers
Impact 4.8-4 Create a Hazard to the Public or the Environment as a Result of Being a Site that is Included on a List of Hazardous Materials Sites Compiled Pursuant to Government Code Section 65962.5	Potentially significant	Implement **MM 4.8-14**, as described above, and **MM 4.8-17** and **MM 4.8-18**, as described under Impact 4.8-5.	Less than significant	All Tiers
Impact 4.8-5 For a Project Located within the Adopted Airport Land Use Compatibility Plan, Result in a	Potentially significant	**MM 4.8-17** The Applicant shall determine whether any proposed construction or alteration meets requirements for notification of the Federal Aviation Administration. If a proposed construction or alteration is found to require notification, the Applicant shall notify the Federal Aviation Administration and request that the Federal Aviation Administration issue a Determination of No Hazard to Air Navigation. If the Federal Aviation Administration determines that the construction or alteration would result in a potential hazard to air navigation, the Applicant would be required to work with the Federal Aviation Administration to resolve any adverse effects or airport operations. The Applicant	Less than significant	All Tiers

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Safety Hazard for People Residing or Working in the Area		shall notify the Federal Aviation Administration and the nearest Airport, by completing and submitting Federal Aviation Administration Form 7460-1 if oil and gas related exploration, production, or associated development activities are planned that meet one or more of the following criteria: a. Any construction or alteration exceeding 200 feet above ground level. b. Any construction or alteration within 20,000 feet of all public use airports except Poso-kern Airport which exceeds a 100:1 surface from any point on the runway. c. Any construction or alteration within 10,000 feet of the Poso-Kern Airport which exceeds a 50:1 surface from any point on the runway. d. Any construction or alteration within 5,000 feet of a public use heliport which exceeds a 25:1 surface. e. When requested by the Federal Aviation Administration. f. Any construction or alteration located on a public use airport or heliport regardless of height or location. **MM 4.8-18** The Applicant shall determine the distance from the proposed operation to the nearest boundary of the Joint Service Restricted R-2508 Complex, using a map of this Complex provided by the County. The Applicant shall notify the Joint Service Restricted R2508 Complex representative identified by the County if oil and gas related exploration, production, or associated development activities are planned that meet one or more of the following criteria: a. Any structure within 75 miles of the R-2508 Complex that is greater than 50 feet tall. b. Any project within 50 miles of the R-2508 Complex that emit radio and communication frequencies. c. Any project that would create environmental impacts such as visibility or elevated obstructions within 25 miles of the R-2508 Complex. **MM 4.8-19** All oil and gas related development activities shall review the Kern County Airport Land Use Compatibility Plan for compliance with all applicable policies.		
Impact 4.8-6 Result in Safety Hazard for People Residing or Working in Project Area within Vicinity of a Private Airstrip	Less than significant	None required.	Less than significant	All Tiers
Impact 4.8-7 Impair Implementation of, or Physically Interfere with, an Adopted Emergency Response Plan or Emergency Evacuation Plan	Less than significant	None required.	Less than significant	All Tiers

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Impact 4.8-8 Expose People or Structures to a Significant Risk of Loss, Injury, or Death Involving Wildland Fires, Including Where Wildlands are Adjacent to Urbanized Areas or Where Residences are Intermixed with Wildlands	Less than significant	**MM 4.8-20** The Applicant is required to implement the following measures: a. Comply with Kern County Fire Codes. b. Maintain firefighting apparatus and supplies required by the Kern County Fire Department. c. Maintain of a list of all relevant fire-fighting authorities for each work site d. Have available equipment to extinguish incipient fires and or construction of a fire break, such as: chemical fire extinguishers, shovels, axes, chain saws, etc. e. Carry water or fire extinguishers and shovels in non-passenger vehicles in the field. f. Have and maintain a supply of fire extinguishers for welding, grinding, and brushing crews in compliance with the in compliance with CalOSHA regulations. g. Use available resources to protect individual safety and to contain any fire that occurs and notify local emergency response personnel. h. Remove any flammable wastes generated during oil and gas activities regularly. i. Store all flammable materials used in oil and gas activities away from ignition sources and in approved containers. j. Allow smoking only in designated smoking areas. k. Prohibit smoking where flammable products are present and when the fire hazard is high. Train personnel regarding potential fire hazards and their prevention. l. All internal combustion engines, stationary and mobile, shall be equipped with spark arresters. Spark arresters shall be in good working order. m. Light trucks and cars with factory-installed (type) mufflers shall be used only on roads where the roadway is cleared of vegetation. Said vehicle types shall maintain their factory-installed (type) muffler in good condition. n. Fire rules shall be posted on the Project bulletin board at the contractor's field office and areas visible to employees. o. Equipment parking areas and small stationary engine sites shall be cleared of all extraneous flammable materials. p. Personnel shall be trained in the practices of the Fire Safety Plan relevant to their duties. Construction and maintenance personnel shall be trained and equipped to extinguish small fires in order to prevent them from growing into more serious threats. **MM 4.8-21** The Applicant should restrict the use of chainsaws, chippers, vegetation masticators, grinders, tractors, torches, and explosives at its locations, and ensure the sites where this equipment is used are equipped with portable or fixed fire extinguishers and/or a water tank, with hoses, fire rakes, and other tools to extinguish and or control incipient stage fires. The Worker Environmental Awareness Program shall include fire prevention and response training for workers using these tools.	Less than significant	All Tiers
Impact 4.8-9 Generate Vectors or Have a Component that Includes Agricultural Waste Exceeding Adopted Qualitative Thresholds	Less than significant	Implement dust control and Valley Fever education and mask measures as described in Section 4.3, Air Quality, and **MM 4.8-22** Applicants shall ensure that trash is stored in closed containers and removed from the site at regular intervals. Open containers shall be inverted and construction ditches shall not be allowed to accumulate water. Construction and maintenance operations shall not generate standing water. Naturally occurring depressions, drainages, or pools at the site shall not be drained or filled without a permit from any regulatory agency having jurisdiction over the resource location.	Less than significant	All Tiers
Impacts 4.8-10 Contribute to Cumulative Hazards and Hazardous Materials Impacts	Potentially significant	Implement **MM 4.8-1** through **MM 4.8-22**, as described above, and dust control and toxic air contaminant setback mitigation measure, as described in Section 4.3, Air Quality, risk reduction measures, as described in Section 4.6, Geology and Soils, and mitigation measures to maintain water quality, as described in Section 4.9, Hydrology and Water Quality.	Less than significant	All Tiers

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Land Use and Planning				
Impact 4.10-1 Physically Divide an Established Community	Less than significant	Implement specified mitigation measures, including those that are applicable from Section 4.1, Aesthetics and Visual Resources, Section 4.3, Air Quality, Section 4.4 Biological Resources, Section 4.12, Noise, Section 4.15, Recreation, and Section 4.17, Utilities and Service Systems.	Less than significant	All Tiers
Impact 4.10-2 Conflict with Any Applicable Land Use Plan, Policy, or Regulation of an Agency with Jurisdiction Over the Project	Less than significant	No mitigation measures are required.	Less than significant	All Tiers
Impact 4.10-3 Conflict with Any Applicable Habitat Conservation Plan or Natural Community Conservation Plan	Less than significant	No mitigation measures are required.	Less than significant	All Tiers
Impact 4.10-4 Contribute to Cumulative Land Use Impacts	Less than significant	No mitigation measures are required.	Less than significant	All Tiers
Minerals				
Impact 4.11-1 Result in the Loss of Availability of a Known Mineral Resource that Would be of Value to the Region and the Residents of the State	Less than significant	No mitigation measures are required.	Less than significant	All Tiers
Impact 4.11-2 Result in the Loss of Availability of a Locally Important Mineral Resource Recovery Site Delineated on a Local General Plan, Specific Plan, or Other Land Use Plan	Less than significant	No mitigation measures are required.	Less than significant	All Tiers
Impact 4.11-3 Contribute to Cumulative Mineral Resources Impacts	Less than significant	No mitigation measures are required.	Less than significant	All Tiers
Population and Housing				
Impact 4.13-1 Induce Substantial Population Growth in an Area, Either Directly or Indirectly	Less than significant	No mitigation measures are required.	Less than significant	All Tiers

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Impact 4.13-2 Displace Substantial Numbers of Existing Housing, Necessitating the Construction of Replacement Housing Elsewhere	No Impact	No mitigation measures are required.	Less than significant	All Tiers
Impact 4.13-3 Displace Substantial Numbers of People, Necessitating the Construction of Replacement Housing Elsewhere	No impact	No mitigation measures are required.	Less than significant	All Tiers
Impact 4.13-4 Cumulative Impact on Population and Housing	Less than significant	No mitigation measures are required.	Less than significant	All Tiers
Public Services				
Impact 4.14-1 Result in Substantial Adverse Physical Impacts Associated with the Provision of New or Physically Altered Governmental Facilities, Need for New or Physically Altered Governmental Facilities, the Construction of which could Cause Significant Environmental Impacts, in Order to Maintain Acceptable Service Ratios, Response Times, or Other Performance Objectives for Any of the Public Services, which Include: Fire Protection, Police Protection, Schools, Parks, and Other Public Facilities	Potentially significant	**MM 4. 14-1** Applicant shall provide funding in the amount of $ 425 per Oil and Gas Conformity Review permit issued for the Sheriff's Rural Crime Unit. Funding shall be used for one Sergeant, two Senior Deputies (investigators), three Deputies, One Support Technician (clerical) and helicopter usage, based on the amount of funding provided by this permit mitigation fee. The Sheriff's department shall annually report on the expenditure of funds for the Rural Crimes Unit, including incident reports and response times. If other sources of funding for the Rural Crimes Unit are secures, then the mitigation amount shall be adjusted to pay only the gap between actual costs and funding provided from other sources.	Less than significant	All Tiers
Impact 4.14-2 Contribute to Cumulative Public Service Impacts	Potentially significant	Implement **MM 4.14-1**, as described above.	Less than significant	All Tiers
Recreation				
Impact 4.15-1 Increase the Use of Existing Neighborhood and Regional Parks or Other Recreational Facilities Such That Substantial Physical Deterioration Would Occur or Be Accelerated	Less than significant	No mitigation measures required.	Less than significant	All Tiers
Impact 4.15-2 Include Recreational Facilities or Require Construction or Expansion of Recreational	Less than significant	No mitigation measures required.	Less than significant	All Tiers

Table 1-6: 2015 FEIR (and 2020 Clarified) Impacts, Mitigation Measures, and Level of Impacts after Mitigation

Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
Facilities That Might Have an Adverse Physical Effect on the Environment				
Impact 4.15-3 Cumulative Impact on Recreational Facilities	Less than significant	No mitigation measures required.	Less than significant	All Tiers
Transportation and Traffic				
Impact 4.16-1 Conflict with an Applicable Plan, Ordinance, or Policy Establishing Measures of Effectiveness for the Performance of the Circulation System, Including, but Not Limited to, Intersections, Streets, Highways and Freeways, Pedestrian and Bicycle Paths, and Mass Transit	Potentially significant	**MM 4.16-1** The Applicant shall pay a road maintenance mitigation fee of $1,500 per permit for new wells to pay for roadway maintenance and related improvements to address wear and tear on roads caused by oil and gas industry traffic. The Kern County Public Works Department shall annually report on the expenditure of funds from the Oil and Gas Roadway Maintenance Fee. Expenditures from the fund shall be as determined by the Roads Commissioner, using as a reference the list of roadways identified in the Environmental Impact Report as being used for traffic by the oil and gas industry. If Kern County secures funding from a sales tax dedicated to transportation funding, then the amount of the traffic mitigation fee shall be re-evaluated at the time the County becomes a self-help county. The first 100 permits issued in a calendar year to certified small producers under the Small Producers Program included in the Project shall not pay this mitigation fee based on their very low proportionate roadway use (100 permits are estimated to generally be less than 5% of the permits issued annually). **MM 4.16-2** Applicants who are using an arterial or collector, or Caltrans route, for access to a construction site, shall consult with the Kern County Public Works Department. The Kern County Public Works Department based on established engineering safety standards and current traffic generation data will determine if a Construction Traffic Control Plan is required based on the timing and volume of larger vehicle rigs and the volume of traffic to address public safety and congestion management. If a Plan is required, the Applicant shall prepare and submit a Construction Traffic Control Plan to the Kern County Public Works Department and to the California Department of Transportation (District 9 office) for approval. The Construction Traffic Control Plan must be prepared in accordance with both the California Department of Transportation Manual on Uniform Traffic Control Devices and Work Area Traffic Control Handbook and shall include, but not be limited to, the following issues a. Timing of deliveries or heavy equipment and building materials. b. Placing temporary signage, lighting and traffic control devices as necessary to indicate the presence of heavy vehicles and construction traffic. c. Specifying construction work hours and arrival/departure times outside peak traffic periods. d. Ensuring access for emergency vehicles to the project site. e. Any temporary closure of travel lanes or disruptions to street segments and intersections during sell development. f. Maintaining access to adjacent property.	Less than significant	All Tiers
Impact 4.16-2 Conflict with an Applicable Congestion Management Program, Including, but Not Limited to Level of Service Standards And Travel Demand Measures, or Other Standards Established by the County Congestion Management Agency for Designated Roads or Highways -Metropolitan Bakersfield General Plan Level of Service “C”	Less than significant	Implement **MM 4.16-2**, as described above.	Less than significant after mitigation	All Tiers

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Impact	Level of Significance before Mitigation	Mitigation Measure(s)	Level of Significance after Mitigation	Applicable Tier
-Kern County General Plan Level of Service "D" -Caltrans Endeavors to Maintain a Target Level of Service at the Transition between Level of Service "C" and Level of Service "D"				
Impact 4.16-3 Result in a Change in Air Traffic Patterns, including Either an Increase in Traffic Levels or a Change in Location that Results in Substantial Safety Risks	Potentially significant	Implement airport-related mitigation measures, as described in Section 4.8, Hazards and Hazardous Materials.	Less than significant after mitigation	All Tiers
Impact 4.16-4 Substantially Increase Hazards due to a Design Feature (e.g., Sharp Curves or Dangerous Intersections) or Incompatible Uses	Potentially significant	Implement **MM 4.16-2**, as described above.	Less than significant after mitigation	All Tiers
Impact 4.16-5 Result in Inadequate Emergency Access	Potentially significant	Implement **MM 4.16-2**, as described above.	Less than significant after mitigation	All Tiers
Impact 4.16-6 Conflict with Adopted Policies, Plans, or Programs regarding Public Transit, Bicycle, or Pedestrian Facilities, or Otherwise Decrease the Performance or Safety of Such Facilities	Potentially significant	Implement **MM 4.16-2**, as described above.	Less than significant after mitigation	All Tiers
Impact 4.16-7 Cumulative Impacts on Transportation and Traffic	Potentially significant	Implementation of **MM 4.16-1** and **MM 4.16-2**, as described above.	Less than significant after mitigation	All Tiers

Chapter 2
Introduction

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2.1 Intent of California Environmental Quality Act

The Kern County Planning and Natural Resources Department (KCPNR), as Lead Agency, has determined that a Supplemental Recirculated Environmental Impact Report (SREIR) is the appropriate environmental analysis document, pursuant to the California Environmental Quality Act (CEQA), for the proposed Revisions to Title 19 – Kern County Zoning Ordinance (2020A), focused on Chapter 19.98 (Oil and Gas Production) of the Kern County Zoning Ordinance for Oil and Gas Local Permitting, and related provisions of the Kern County Zoning Ordinance ("Project" or "proposed Project"), as described in detail in Section 3.1.1 (see Chapter 3, Project Description).

The public process for this project has resulted in two draft SREIRs that have been prepared and circulated for public comment. The first draft SREIR was completed in August 2020 and is referred to as the SREIR (August 2020), and this second draft SREIR has been released in October 2020 and is referred to as the SREIR (October 2020). This SREIR (October 2020) shows all text changes from the earlier SREIR (August 2020) as italics, with text additions underlined and text deletions as strikeouts. Unless otherwise noted, all references to the SREIR refer to this SREIR (October 2020). This SREIR has been prepared in accordance with requirements of the following documents:

- CEQA (California Public Resources Code [PRC] Section 21000 et seq.);
- State CEQA Guidelines, Title 14, California Code of Regulations (CCR), Chapter 3, Section 15000 et seq.; and
- Kern County CEQA Implementation Document.

The overall purposes of the CEQA process are as follows:

- Inform governmental decision makers and the public about the potential significant effects, if any, of proposed activities;
- Provide opportunities for other agencies and the public to review and comment on draft environmental documents;
- Ensure that the environment and public health and safety are protected in the face of discretionary projects initiated by public agencies or private concerns;
- Identify the significant effects to the environment of a project, identify alternatives, and indicate the manner in which those significant effects can be avoided or mitigated; and

- Provide for full disclosure of the project's environmental effects to the public, the agency decision makers who will approve or deny the project, and responsible and trustee agencies charged with managing resources (e.g., wildlife, air quality) that may be affected by the project.

2.2 Purpose of this Supplemental Recirculated Environmental Impact Report

An environmental impact report (EIR) is a public informational document used in the planning and decision making process. This SREIR analyzes the environmental impacts of the proposed Project. The Kern County Planning Commission and Board of Supervisors will consider the information in the SREIR, including public comments and staff responses to those comments, during the public hearing process. As amending the Zoning Ordinance is a legislative action, the final decision will be made at the Board of Supervisors' public hearing, where the Project may be approved, conditionally approved, or denied.

The purpose of this SREIR is to correct deficiencies identified by the court in the 2015 Final EIR (FEIR), and analyze potential impacts to agricultural resources, air quality, hydrology and water quality, noise, and utilities and service systems. ~~To support this purpose,~~ <u>*This SREIR will provide the following the information and analysis*</u>~~: is to identify:~~

- The significant potential impacts of a proposed project on the environment in relation to the five topic areas identified by the Courts and the manner in which those significant impacts can be avoided or mitigated;
- Any unavoidable adverse impacts that cannot be mitigated in relation to the five topic areas identified by the Courts; and
- Reasonable and feasible alternatives to the project that would eliminate any significant adverse environmental impacts or reduce the impacts in relation to the five topic areas identified by the Courts to a less than significant level.

An SREIR also discloses growth-inducing impacts, impacts found not to be significant, and significant cumulative impacts of past, present, and reasonably anticipated future projects.

CEQA requires an EIR to reflect the independent judgment of the lead agency regarding the impacts, the level of significance of the impacts both before and after mitigation, and mitigation measures proposed to reduce the impacts. A Draft EIR (DEIR) is circulated to public agencies, special districts, responsible and trustee agencies who manage resources affected by the project, and interested agencies and individuals. The purposes of public and agency review of a DEIR include sharing expertise, disclosing agency analyses, checking for accuracy, detecting omissions, discovering public concerns, and soliciting counterproposals.

<u>*The first draft SREIR (August 2020) was issued for a 45-day public comment period. During the public comment period, a virtual public workshop was held to explain the Project and public*</u>

process and receive written comments. Spanish translation was available for listeners to the virtual workshop, as well as closed captioning. The virtual workshop did not provide an opportunity for oral comments in any language. Twelve comment letters were received during the public comment period, and one additional comment letter (dated October 2, 2020) was received after the 45-day period ended. During the virtual public workshop, nine participants made written comments. All comments received on the SREIR (August 2020) are included in Appendix G to this SREIR (October 2020).

Comments on the SREIR (August 2020) addressed multiple topics. A list of comments, the full text of all written comments received, and a transcript of the public workshop are included in Appendix G of this SREIR (October 2020). Some comments included submittal of technical reports. This SREIR (October 2020) includes additional *analysis and text modifications to address the technical reports submitted in comments in response to the earlier SREIR (August 2020), a full analysis of the alternative for a 2,500-foot setback from sensitive receptors, and additional analyses and mitigation from the lead agency.*

To provide members of the public and interested parties with an opportunity to review this additional analysis and text changes in this second SREIR (October 2020), a second 45-day public comment period and public workshop will be provided. Responses to comments made on the initial draft SREIR (August 2020), as well as this second Draft SREIR (October 2020), will be provided in a single comprehensive Response to Comments document (Chapter 7) as part of the Final SREIR for consideration by the Planning Commission and Board of Supervisors.

Reviewers of this *draft SREIR (October 2020)* ~~*Draft Supplemental Recirculated EIR (DSREIR)*~~ should focus on the sufficiency of the document in identifying and analyzing the possible impacts on the environment and ways in which the significant effects of the Project might be avoided or mitigated. Comments are most effective when they suggest additional and specific alternatives or mitigation measures that would provide better ways to avoid or mitigate significant environmental effects. *For reading purposes, changes to the SREIR (August 2020) are all italicized, and text additions are underlined and text deletions are strikeouts.*

Issues to Be Resolved

Section 15123(b) (3) of the CEQA Guidelines requires that an EIR contain issues to be resolved, which include the choices among alternatives and whether or how to mitigate significant impacts. The major issues to be resolved regarding a project include decisions by the lead agency as to whether:

- The SREIR adequately describes the environmental impacts of the project;
- The recommended mitigation measures should be adopted or modified;
- The alternatives evaluated should be adopted or rejected; or
- Additional mitigation measures need to be required.

2.2.1 Analysis Required by Court

In 2012 representatives of the oil and gas industry associations, specifically the California Independent Petroleum Association (CIPA), the Independent Oil Producers Agency (IOPA), and the Western States Petroleum Association (WSPA), (collectively, "Project Proponents"), requested an amendment to Chapter 19.98 (Oil and Gas Production) and related chapters of the Kern County Zoning Ordinance to include additional provisions for local permitting of oil and gas activities. Under Chapter 19.112, amendments to the text of the Zoning Title of the Kern County Zoning Ordinance can only be initiated by the Kern County Board of Supervisors. The request was considered in a public hearing before the Board of Supervisors on January 22, 2013, and the Board directed Planning and Community Development Staff (now renamed Planning and Natural Resources Department) to proceed with processing the requested amendments. After a public process of workshops, circulation of the Notice of Preparation and DEIR and consideration at a noticed Planning Commission hearing with a recommendation to the Board for adoption, on October 9, 2015, Kern County (County) certified an FEIR and approved the proposed Ordinance revisions as amendments to Title 19. Permitting was started and a history of that permitting, which commenced on December 9, 2015, and ended March 25, 2020, can be found in Section 1.3.1, History of Local Oil and Gas Permitting.

Several parties filed lawsuits challenging the adequacy of the certified EIR, and the cases were consolidated in the Kern County Superior Court. On April 20, 2018, the Court issued a judgment upholding the EIR in its entirely except for requiring supplemental environmental review under CEQA for two issues. The judgment did not vacate any portion of the Ordinance or the EIR. The County subsequently prepared and circulated a draft Supplemental Environmental Impact Report (SEIR) in response to the judgment. The SEIR was certified by the County Board of Supervisors on December 11, 2018, and was not legally challenged.

Several parties appealed the judgment to the Fifth Appellate District of the California Court of Appeal (Appellate Court). In October 2019 the Appellate Court rejected certain constitutional claims against the Ordinance amendments. On February 25, 2020, the Appellate Court issued an opinion that upheld the judgment and the adequacy of the certified EIR except for "five areas in which the EIR did not comply with CEQA: (1) mitigation of water supply impacts; (2) impacts from $PM_{2.5}$ (particles up to 2.5 microns in diameter) emissions; (3) mitigation of conversion of agricultural land; (4) noise impacts; and (5) recirculation of the Multi-Well Health Risk Assessment for public review and comment." The opinion directed the Superior Court to set aside the certification of the EIR and the previously approved Ordinance amendments, effective March 25, 2020. The opinion states that "pending CEQA compliance, the County will return to the regulatory scheme in place prior to the ordinance's adoption." The opinion further directs the County, "in the event it decides to present the Ordinance (in its present or a modified form) to the Board for approval, to correct the CEQA violations identified in this opinion," to prepare "a revised EIR correcting the CEQA violations," and to prepare and publish "responses to the comments received before certifying the revised EIR and reapproving the Ordinance."

The purpose of this SREIR is to provide analysis to address the CEQA deficiencies found by the Appellate Court decision, and provide compliance for CEQA for the reconsideration by the Planning Commission and Board of Supervisors of the Zoning Ordinance revisions (2020 A) focused on Oil and Gas Local Permitting.

2.2.2 Supplemental Analysis

The purpose of this SREIR is to provide the analysis required to address the CEQA deficiencies in the Project's 2015 FEIR that were identified in the Appellate Court opinion issued on February 25, 2020. That decision held that the certified EIR was adequate except for "five areas in which the EIR did not comply with CEQA: (1) mitigation of water supply impacts; (2) impacts from $PM_{2.5}$ emissions; (3) mitigation of conversion of agricultural land; (4) noise impacts; and (5) recirculation of the Multi-Well Health Risk Assessment for public review and comment." The opinion set aside the previously approved Ordinance amendments and the certification of the 2015 FEIR. The opinion further directs the County, "in the event it decides to present the Ordinance (in its present or a modified form) to the Board for approval, to correct the CEQA violations identified in this opinion," to prepare "a revised EIR correcting the CEQA violations," and to prepare and publish "responses to the comments received before certifying the revised EIR and reapproving the Ordinance."

This SREIR is a supplemental analysis of the CEQA deficiencies in five topical sections of this Chapter 4: Section 4.2, Agriculture and Forest Service; Section 4.3, Air Quality; Section 4.9, Hydrology and Water Quality; Section 4.12, Noise; and Section 4.17, Utilities and Service Systems. *This SREIR (October 2020) includes additional analysis and text modifications to address the technical reports submitted in comments in response to the earlier SREIR (August 2020), a full analysis of the alternative for a 2,500-foot setback from sensitive receptors, and additional analyses and mitigation measures.*

This numbering corresponds to the named chapters in the 2015 FEIR (SREIR Volume 3) and provides for reference to other analyses, which the court found legally valid.

The 2015 adopted Ordinance has been implemented by Kern County as Lead Agency through the Kern County Planning and Natural Resources Department Oil and Gas Permitting program (December 9, 2015, to March 25, 2020) and this implemented permit system is described in Section 1.3, Project History, and in Section 3.4.1, Proposed Project/Proposed Zoning Ordinance. As described in Chapter 3, Project Description, the Project includes minor administrative changes to the 2015 Ordinance, and clarifications for some of the mitigation measures, to further improve the ministerial permit process. These clarifications are informed by the County's implementation experience to ensure applicant compliance and informed by the adopted process and online permit system as well as administrative materials prepared by the County to provide guidance and direction to the applicants on submitting applications and implementing mitigation measures.

As described in Section 3.1.1, Revisions to Title 19-Kern County Zoning Ordinance (2020), the ~~*only*~~ changes to the 2015 Ordinance are additional application processing details for online management of permits, *including extension of time and abandonment activities,* clarification of the process for monitoring Split Estate 120-day process, updates of names of County departments and State agencies that have changed since 2015, references to this SREIR, and adjustment of Tier Maps for errors identified from the 2015 adoption. These Ordinance revisions do not authorize new or different industry activities and will not result in any changes to the physical environment warranting further CEQA review *beyond this SREIR.*

The Ordinance also requires implementation of the mitigation measures from the 2015 FEIR. Some of these mitigation measures have been modified based on *the SREIR (August 2020) and* this SREIR *(October 2020)* analyses and are further described in Sections 4.2, Agriculture and Forest Service; 4.3, Air Quality; 4.9, Hydrology and Water Quality; 4.12, Noise; and 4.17, Utilities and Service Systems. In addition, a comprehensive review has been completed of all mitigation measures from the 2015 FEIR to identify clarifications that should be made in identified mitigation measures for minor word modifications.

Clarifying word modifications made as part of this comprehensive evaluation for mitigation measures for other topical EIR sections are identified in the Section 4.18, Supplemental Analysis. Clarifying word modifications *to the SREIR (August 2020)* are shown in strikethrough and underline with replacement wording for reading purposes*; further revisions made in this SREIR (October 2020) are shown in italic strikethrough and underline*. The recommended clarified mitigation measures are also shown in final form. As the name of County departments and State agencies have changed since 2015, these changes will be automatically made for mitigation measures that have no other changes. The complete analysis of the impact and Section 4.18, Supplemental Analysis, mitigation measures are contained in the 2015 FEIR sections for each topical area (see the 2015 FEIR [SREIR *(October 2020)* Volume 3]).

This SREIR (October 2020) also includes appendices to address the analysis: Appendix B-1, Supplemental Health Risk Assessment Technical Memorandum (October 2020); Appendix E, Supplemental Noise Technical Memorandum (October 2020); Appendix F, Sensitive Receptor Community Analysis (October 2020); and Appendix G, Comments Received on the Draft SREIR (August 2020).

2.3 Terminology

To assist readers in understanding this SREIR, terms used are defined in the following manner:

- "**Project**" means the whole of an action that has the potential for resulting in a physical change in the environment, or a reasonably foreseeable indirect physical change in the environment.
- "**Project Area"** means the area within which the proposed amendment to Title 19 – Kern County Zoning Ordinance, focused on Chapter 19.98 (Oil and Gas Production) of the Kern County Zoning Ordinance for Oil and Gas Local Permitting would apply and generally includes most of the San Joaquin Valley Floor portion of Kern County up to an elevation of 2,000 feet. The Project Area includes all unincorporated lands within the 409-square-mile Metropolitan Bakersfield General Plan; but excludes portions of Metropolitan

Bakersfield that are within the jurisdiction of the City of Bakersfield, and excludes all other city jurisdictions, including Taft, Delano, Shafter, Arvin, McFarland, Maricopa, and Wasco. Lands under the jurisdiction of various state and federal agencies, including the Bureau of Land Management (BLM), the U.S. Fish and Wildlife Service (USFWS), and the California State Lands Commission (CSLC) are also excluded.

- "**Environment**" means the physical conditions that exist within the area that will be affected by the proposed Project, including, but not limited to, land, air, water, minerals, flora, fauna, ambient noise, and objects of historical or aesthetic significance. The area involved is the locale in which significant direct or indirect impacts would occur as a result of the Project. The environment includes both natural and man-made conditions.
- "**Impacts**" analyzed under CEQA are changes to the physical environment anticipated from a development proposal. Impacts are:
  - Direct or primary – Impacts that are caused by the proposed Project and occur at the same time and place of Project implementation; or
  - Indirect or secondary – Impacts that are caused by the proposed Project at a later time or farther removed in distance but are still reasonably foreseeable. Indirect or secondary impacts may include growth-inducing impacts and other effects related to induced changes in the pattern of land use, population density or growth rate, or related effects on air, water, and other natural systems, including ecosystems.
- "**Significant impact on the environment**" means a substantial, or potentially substantial, adverse change in any of the physical conditions in the Project vicinity affected by the proposed Project, including land, air, water, minerals, flora, fauna, ambient noise, and objects of historical or aesthetic significance. An economic or social change resulting from a project by itself is not considered a significant impact on the environment. A social or economic change related to a physical change may be considered in determining whether the physical change is significant.
- "**Mitigation**" consists of measures to avoid or substantially reduce the proposed Project's significant environmental impacts by:
  - Avoiding the impacts altogether by not taking a certain action or parts of an action;
  - Minimizing impacts by limiting the degree or magnitude of the action and its implementation;
  - Rectifying the impact by repairing, rehabilitating, or restoring the affected environment;
  - Reducing or eliminating the impact over time by preservation and maintenance operations during the life of the actions; or
  - Compensating for the impacts by replacing or providing substitute resources or environments.

- **"Cumulative Impacts"** are two or more individual impacts that, when considered together, are considerable or that compound or increase other environmental impacts. The following statements also apply when considering cumulative impacts:
  - The individual impacts may be changes resulting from a single project or separate projects; and
  - The cumulative impact from several projects is the change in the environment that results from the incremental impact of the Project when added to other closely related past, present, and reasonably foreseeable probable future projects. Cumulative impacts can result from individually minor, but collectively significant, projects taking place over time.

This SREIR uses a variety of terms to describe the level of significance of adverse impacts. These terms are defined as follows:

- **Less than significant**: An impact that is adverse but that does not exceed the defined thresholds of significance. Less than significant impacts do not require mitigation.
- **Significant**: An impact that exceeds the defined thresholds of significance and would or could cause a substantial adverse change in the environment. Mitigation measures are recommended to eliminate the impact or reduce it to a less than significant level.
- **Significant and unavoidable**: An impact that exceeds the defined thresholds of significance and cannot be eliminated or reduced to a less than significant level through the implementation of mitigation measures.

A glossary, including acronyms, abbreviations, and specific technical terms used in the SREIR is provided in Chapter 11 of this SREIR.

2.4 Decision-Making Process

CEQA requires lead agencies to solicit and consider input from other interested agencies, citizen groups, and individual members of the public. CEQA also requires the Project to be monitored after it has been permitted to ensure that mitigation measures are carried out.

CEQA requires the lead agency to provide the public with a full disclosure of the expected environmental consequences of the Project and with an opportunity to provide comments. In accordance with CEQA, the following is the process for public participation in the decision-making process:

- **Initial Study (IS)/Notice of Preparation (NOP).** Kern County prepared and circulated an IS/NOP to the State Clearinghouse, public agencies, special districts, responsible and trustee agencies, and other interested parties for review and comment on April 29, 2020. In conjunction with this public notice, a virtual scoping meeting was held by Kern County on May 13, 2020, via Microsoft Live Events. The purpose of the meeting was to introduce the Project and to solicit input from agencies, organizations, and other interested parties regarding the proposed Project, alternatives, mitigation measures, and environmental impacts to be analyzed in the SREIR. The IS/NOP, scoping meeting materials, comment letters received, and a complete summary of all questions received during the scoping meeting are included in Appendix A of this SREIR.

- **Preparation of ~~D~~*Draft*~~–~~SREIR *(August 2020)/*Notice of Completion (NOC)**. The ~~D~~SREIR *(August 2020) was* ~~will be~~ prepared, incorporating public and agency responses to the IS/NOP and scoping process. The ~~D~~SREIR *(August 2020) was* ~~will be~~ circulated for review and comment to appropriate agencies and additional individuals and interest groups who have requested to be notified of EIR projects. Per Section 15105 (Public Review Period for a DEIR or a Proposed Negative Declaration or Mitigated Negative Declaration) of the State CEQA Guidelines, Kern County ~~will~~ provide*d* for a 45-day public review period on the ~~D~~SREIR *(August 2020)*. The NOC *was* ~~will be~~ prepared with the DSREIR *(August 2020)* in accordance with Section 15085 (Notice of Completion) of the CEQA Guidelines. The purpose of the NOC is to notify reviewing agencies and the public that a ~~D~~SREIR has been prepared and completed for public review.

- ***Preparation of Draft SREIR (October 2020)/Notice of Completion (NOC)****. This SREIR (October 2020) incorporates public and agency comments on the previously circulated draft SREIR (August 2020). This SREIR (October 2020) will be circulated for review and comment to appropriate agencies, and additional individuals and interest groups who have requested to be notified of EIR projects, as well as those who commented on the SREIR (August 2020). All will receive a Notice of Availability with a flash drive electronic copy of the document, which will also be posted on the department website. Per Section 15105 (Public Review Period for a DEIR or a Proposed Negative Declaration or Mitigated Negative Declaration) of the State CEQA Guidelines, Kern County is providing for a 45-day public review period for the SREIR (October 2020). The NOC was prepared with the SREIR (October 2020) in accordance with Section 15085 (Notice of Completion) of the CEQA Guidelines. The purpose of the NOC is to notify reviewing agencies and the public that a SREIR has been prepared and completed for public review.*

- **Preparation of Final SREIR (FSREIR)**. In accordance with Section 15088 (Evaluation of and Response to Comments) of the CEQA Guidelines, following completion of the 45-day public review period, Kern County will respond to each comment on the *draft* SREIR *(August 2020) and draft SREIR (October 2020)* through a "Response to Comments" chapter in the FSREIR. Written responses will be provided to each commenting agency, organization, or person at least two weeks before the scheduled Kern County Planning Commission hearing.

- **Certification of FSREIR**. Acting as an advisory body to the Kern County Board of Supervisors, the Kern County Planning Commission will consider and make recommendations on the FSREIR and proposed Zoning Ordinance amendment. Upon receipt of the Planning Commission's recommendations, the Board of Supervisors will consider the FSREIR, all public comments, and the proposed Zoning Ordinance amendment before taking final action on the Project. At least one public hearing will be held by the Planning Commission and by the Board of Supervisors to consider the FSREIR, take public testimony, and either approve, conditionally approve, or deny the proposed Project.

- **Preparation of Notice of Determination (NOD)**. In accordance with Section 15094 (Notice of Determination), within five working days following certification of the FSREIR, Kern County shall prepare and file the NOD with the State Clearinghouse. The NOD, which notifies the public that Kern County has certified the FSREIR, will be posted for at least 30 days.

2.4.1 Initial Study/Notice of Preparation

In accordance with CEQA Guidelines Section 15082 (a) (Notice of Preparation) and the County's Guidelines, the KCPNR circulated an IS/NOP for a 30-day public review. The IS/NOP was sent to the State Clearinghouse, public agencies, special districts, responsible and trustee agencies, and other interested parties for a public review period that began on April 29, 2020, and ended on May 29. 2020. The purpose of the IS/NOP is to formally covey that Kern County, as the lead agency, solicited input regarding the scope and proposed content of the SREIR. The IS/NOP, scoping meeting, and community workshop materials, comment letters received, and a complete summary of all scoping comments are included as Appendix A.

IS/NOP Written Comments

The County received nine letters with substantive comments in response to the IS/NOP. The comments are summarized in Table 2-1.

Table 2-1: Summary of Comments on the Notice of Preparation for the Supplemental Recirculated Environmental Report

Commenter	Summary of Comment
State	
California Department of Transportation (Caltrans) Email May 22, 2020	Indicates Caltrans reviewed the Project and has no comments on the project.
Native American Heritage Commission Letter April 29, 2020	Recommends consultation with Native American tribes in geographic area Compliance with AB 52 and SB 18 and provides recommendations for cultural resource assessment.
Local Agencies	
Kern County Fire Department Letter May 28, 2020	Verified receipt of the NOP by the Kern County Fire Department. No comments were made on the content of the NOP.

Table 2-1: Summary of Comments on the Notice of Preparation for the Supplemental Recirculated Environmental Report

Commenter	Summary of Comment
Interested Parties	
Association of Irritated Citizens (AIR) Letter May 29, 2020	Indicates impacts to groundwater from use of produced water for irrigation, the transportation of produced water for treatment, and the use of percolation ponds for produced water not suitable irrigation should be analyzed and the use, transport, and storage of produced must be restricted. Indicates surface exposures or leaking oil coming out of the ground within 500 feet of a stream bed or other watercourse must be stopped immediately. States a fine should be implemented for every barrel of fluid coming to the surface near a streambed or watercourse. Indicates volatile organic compound emissions must be calculated and measured continuously and mitigated. Recommends that all oil field roads carrying oil production–related vehicles and machinery must be treated to reduce dust emissions and oil field operators must prepare a plan to reduce $PM_{2.5}$ direct or precursor emissions by 20% for days when the air district predicts a violation will occur. Recommend requirements to convert oil pumps with combustible engines to electric motors within 6 months and a prohibition on new wells with combustion engines if the electric grid is within 1,500 feet. States all mitigation for $PM_{2.5}$ should be applied in Kern County. Indicates mitigation for impacts related to greenhouse gas and climate change should include the use of photovoltaic solar energy for production equipment, restrictions on flaring, and fines based on the quantity of natural gas that is flared and its retail value. Indicates landowners and farmers should be able to reject drilling locations on farmland and select an alternative site for drilling. States absolutely no drilling mud pits should be used on farmland and all buried and covered drilling mud pits on farmland that have been returned to the farmer for cultivation and irrigation must have all drilling related material removed and filled with clean dirt suitable for agriculture and similar to the pre-existing soil. Recommends that permits limit drilling to no more than one well per 40 acres of farmland or the equivalent of 1 well to 40 acres for multiple wells; if more wells are drilled a lease from the landowner should be required with a minimum payment of $2,500 per acre. Requests requirements that oil wells and pumps be constructed to prevent flooding from storm water and irrigation, including after removal of pumping equipment. States buffer zones for nearby workers should be arranged at least two weeks in advance. Indicates safety signs on above-ground pipelines should be provided in English and Spanish and underground pipelines should be tested monthly for leaks. Request that the SREIR analyze what proportion of the health costs in Kern County is related to oil field production and indirect, but related activities. Indicates flare noise should be reduced beyond current requirements and noise barriers and setbacks should be required around residences, schools, or businesses.

Table 2-1: Summary of Comments on the Notice of Preparation for the Supplemental Recirculated Environmental Report

Commenter	Summary of Comment
Center on Race, Poverty, and Environment. Email May 11,2020	Requests that all members of the public be able to provide oral comments by phone or through Microsoft Teams Live Event in Spanish or English and will be translated during the scoping meeting. Indicates commenters should also be able to comment by phone in Spanish or English. Requests the NOP and all future project related public materials be translated into Spanish.
Earth Justice, Sierra Club, Center for Biological Diversity, Center on Race, Poverty, and the Environment Letter May 15, 2020	Requests an extension of the NOP comment period for 45 days.
Earthjustice, Center for Biological Diversity, Center on Race, Poverty & the Environment, Comité Progreso de Lamont, Comité de Lost Hills en Acción, Committee for a Better Shafter, Committee for a Better Arvin, and Sierra Club. Letter May 29, 2020	Requests that documents related to the Project be provided in Spanish, translation services be provided at all community meetings and public hearings, and comments on the SREIR and zoning ordinance be accepted in Spanish. Indicates that an SREIR is not appropriate and that a new CEQA process must also update and reevaluate other oil and gas impacts to incorporate new circumstances and information that has become available in the last 5 years, including the impacts to wildlife. Indicates new analysis should be completed for impacts to air quality, climate change, health impacts, and water supply impacts based on new studies or changes in circumstances. Indicates the SREIR must evaluate impacts to soil incorporating recent information on surface expressions and other oil leaks. Indicates the SREIR should include the potential costs and risks from idle and abandoned wells. Requests that an analysis of the efficacy of mitigation measures be included in the SREIR based on the 5 years of permitting experience the County has. Requests fees collected pursuant to air quality impact mitigation measures be used to directly benefit those community members in Kern County who experience disproportionate socioeconomic and pollution burdens. Requests the SREIR describe the types of projects that have been funded to date, describe the County's outreach efforts—if any—to identify pollution-reducing projects in disadvantaged communities near oil and gas activity, and evaluate why so few community-based projects have been funded, and identify and evaluate options to ensure that more OGERA funds are spent on projects that benefit the community members most impacted by oil and gas production. Requests the County disclose which mitigation measures have been applied to permits and how the County determined which measures should apply in each case and identify what steps the County has taken to ensure mitigation measures are being properly implemented by operators.
Shute, Milhaly, & Weinberger – Representing King and Gardiner Farms, LLC Letter May 27, 2020	Recommends revising the analysis to include new information since publication of the FEIR and a detailed analysis of the Project's localized impacts. Recommends identifying potential water sources for anticipated development & permitted activities in discrete oil fields and agricultural areas and address the environmental impacts of exploiting those sources and assessing localized impacts on other water users. Recommends revising the County's noise analysis to account for the Project's increase in ambient noise levels and adopt a 5-dB increase over ambient noise

Table 2-1: Summary of Comments on the Notice of Preparation for the Supplemental Recirculated Environmental Report

Commenter	Summary of Comment
	levels as the threshold for evaluating the significance of the Project's increases in temporary and permanent noise. Recommends revising the discussion of mitigation for the Project's noise impacts and updating the description of baseline conditions for noise. Recommends updating the Project baseline. Indicates additional mitigation measures, including the clustering of wells when feasible for reducing the Project's conversion of agricultural land and revised analysis of mitigation for farmland conversions should be considered. Recommends recirculating the Multi-Well Health Risk Assessment and updating the analysis to reflect updated $PM_{2.5}$ data and other relevant new information.
Sierra Club, Kern-Kaweah Chapter Letter May 27, 2020	States the SREIR should acknowledge, embrace, and address CEQA Appendix F goals by discouraging further oil and gas extraction and discuss why it is not a program EIR rather than a project EIR. Recommends updating information on surface water delivery availability pursuant to the State Water Project and Central Valley Project. Indicates the SREIR should analyze the quantity of irrigation water needed mix with produced water for irrigation use, the long-term competing uses for regular irrigation water and the uncertainties associated with long-term regular irrigation water supplies, the environmental impacts and mitigation associated with securing and delivering regular irrigation water supplies including the impact of water diversions on endangered species. Indicates produced water may be used to expand land not currently being used for agriculture and recommends the SREIR analyze the sustainability of this process and impacts on groundwater sustainability plans. Recommends mitigation for agricultural impacts include the requirement of perpetual agricultural conservation easements, at a ratio of three to one on land of equal quality and with similar development pressure, within the southern San Joaquin. Recommends the easement holder be an accredited land trust and an endowment be set up to pay for monitoring and enforcement expenses. Indicates the SREIR should include a list the oilfield chemicals, the salts, the heavy metals, and other chemicals contained in produced water from each of the Kern oilfields and identify acceptable concentrations each chemical and set performance criteria to ensure groundwater quality is not affected by oil and gas operations. Indicates the SREIR should analyze the long-term impact of accumulation of minerals in farmland soil fertility or use by livestock. Indicates the SREIR should analyze the impact of produced water on subsidence in the area of the drill site or elsewhere. Requests the SREIR address the environmental justice and community health aspect of oil production. Requests copies of the SREIR be provided in Spanish and ensure all information about the SREIR is made available in Spanish. Indicates the SREIR should require increased setbacks to at least 2,500 feet. Requests an accounting of the Air Quality mitigation funds received to date that includes a list of all projects that have been funded, amounts for each project, and the county each project is located in. Indicates the SREIR should discuss the effectiveness of the $89 million air fee in reducing air pollution,

Table 2-1: Summary of Comments on the Notice of Preparation for the Supplemental Recirculated Environmental Report

Commenter	Summary of Comment
	and provide conditions to make it more effective, as well as additional mitigation. Requests the SREIR specify that air pollution mitigation funding be spent preferably in Kern County but at least in the southern San Joaquin Valley. Stated the oil industry should fund several measures related to climate change, including: Replacement of the County vehicle fleet with EVs, where feasible; Construction of EV charging stations on appropriate County properties; parking lots should be partially retrofitted with covered structures with solar PV panels PV; retrofit, where feasible solar PV on existing County buildings; and require oilfield use of solar heating or PV to fuel steam injection operations.
Sierra Club, Los Angeles and Citizens Coalition for a Safe Community Email May 8, 2020	Indicates the EIR should be a Programmatic EIR due to the planning horizon for the Project. Requests all communication with the project proponent be provided, a subscription process be provided for notification of future activities related to the SREIR, and that the Scoping Meeting Agenda be provided to all labels for the mailing list. Indicates the NOP is inadequate in that it does not provide a full scoping report, a single list of quantifiable objectives or a statement of which objectives will be given priority, or a list of mitigative or compensatory alternatives to each element considered. Requests the document provide definitions of terms used. Requests the Multi-Well Health Risk Assessment be made available for review, and that review and analysis include the entire document, all versions of the document, and all correspondence regarding the Multi-Well Health Risk Assessment. Recommend incorporating analysis of the interactions of multiple pollutants, a graphical representation of the "sensitive receptors" at various income levels, CARB SNAPS findings.

Key:
AB = Assembly Bill
Caltrans = California Department of Transportation
CARB = California Air Resources Board
CEQA = California Environmental Quality Act
dB = decibels
EIR = Environmental Impact Report
EV = electric vehicle
FEIR = Final Environmental Impact Report
NOP = Notice of Preparation
OGERA = Oil and Gas Emission Reduction Agreement
$PM_{2.5}$ = particles up to 2.5 microns in diameter
PV = photovoltaic
SB = Senate Bill
SNAPS = Study of Neighborhood Air near Petroleum Sources
SREIR = Supplemental Recirculated Environmental Impact Report

2.4.2 Notice of Preparation and Scoping Meeting Results

Pursuant to Section 15206 (Projects of Statewide, Regional, or Area-Wide Significance) of the State CEQA Guidelines, the lead agency is required to conduct at least one scoping meeting for all projects of Statewide, regional, or areawide significance. The scoping meeting is for jurisdictional agencies and interested persons or groups to provide comments regarding, but not limited to, the range of actions, alternatives, mitigation measures, and environmental effects to be analyzed. Kern County hosted a virtual scoping meeting at 1:30 p.m. on May 13, 2020, via a Microsoft Live Event.

Scoping Meeting Results

Questions were received at the scoping meeting which are presented in Table 2-2. The IS/NOP, scoping meeting, comment letters received, and a complete summary of all scoping comments are included as Appendix A.

Table 2-2: Summary of Questions from the Scoping Meeting

– Is there an estimated time frame when all the actions to complete the Oil & Gas Supplemental Recirculated EIR will be done?
– Who are the people on the panel working on the Oil & Gas Supplemental Recirculated EIR and how can we be part of the panel?
– What are the mitigation options for water that the County is thinking of?
– Many of Kern County residents cannot participate on meetings like this one, due to technological barriers, what is the County going to do to ensure full participation?
– Has there been any new developments regarding split state surfaces and the 120 day process?
– Is the "scope" of this plan to reintroduce the EIR with only the 5 request of the courts?
– Why are we rushing thru this process, can't wait until the pandemic is over, more people can participate?
– Will each of the permits in the past 4 years be looked at by the 5 topics the courts introduced?
– On a split state surface were the surface was owned by a trust and the trust had 10 owners would we still need a sign off by all 10 people?
– How can you be sure that the air funds generated by the plan are used in Kern County?
– Can you give a specific date as to how long the old EIR will be available online?
– Will the permits that expire at the end of the month not be granted an extension?"
– Stay safe

2.4.3 SREIR (AUGUST 2020) Comments

The first draft SREIR was completed in August 2020 and is referred to as the SREIR (August 2020). Twelve comment letters were received and are included in Appendix G. The comments are summarized in Table 2-3. A list of commenters at the Public Workshop conducted August 27, 2020, and topics raised by each commenter, is provided in Table 2-4.

Table 2-3: List of Commenters and Comment Topics in Comment Letters on the Draft SREIR (August 2020)

Commenter	**SREIR Topics Addressed in Comment**
Federal	
Edwards Air Force Base Email July 15, 2020	No substantive comments
State	
California Department of Conservation Letter September 16 2020	Agricultural conversion mitigation
Local Agencies	
Kern County Public Works Department Email August 7, 2020	No substantive comments
Interested Parties	
Association of Irritated Citizens (AIR) Letter September 16, 2020	Mitigation of water supply impacts Impacts from $PM_{2.5}$ emissions Mitigation of agricultural land conversion Noise impacts Recirculated Multi-Well Health Risk Assessment
California Resources Corporation Letter September 14, 2020	Health Risk Assessment Attached report
Center on Race, Poverty, and Environment. Letter Comite Lost Hills En Accion, Comite Progreso de Lamont, Comite Rosas Wasco, Committee for a Better Arvin, Greenfield Walking Group, Committee for a Better Shafter, Delano Guardians, Comite Si Se Puede de Ducor, Association of Irritated Residents, Center on Race, Poverty and the Environment, LOUD For Tomorrow, Sunrise Kern, Central California Environmental Justice Network, Leadership Counsel for Justice and Accountability, Central Valley Air Quality Coalition, Our Revolution Kern County, El Pueblo para el Aire & Agua Limpia de Kettleman City, Vision & Compromiso, Central California Ashma Collaborative, Central Valley Partnerhsip, Merced Bicycle Coalition, Mi Familia Vota, Mothers Out Front Fresno, Asian Pacific Environmental Network, Azul, California Environmental Justice Alliance, Communities for a Better Environment, Esperanza Community Housing Corporation, Labor Network for Sustainability, Physicians for Social Responsibility-Los Angeles, Presente.org, VISION (voices in Solidarity Against Oil in Neighborhoods), Sierra Club, Center for Biological Diversity, Earthjustice, Natural Resources Defense Council, 350 Bay Area, 350 Conejo/San Fernando Valley, 350 Santa Barbara, 350 Silicon Valley, 350 South Bay Los Angeles, 5 Gyres Institute, 99 Rootz, Alameda County Interfaith Climate Action Network, Alliance of Nurses for Healthy Environments, Amazon Watch, Breast Cancer Action, Breats Cancer Prevention	Accessibility of public comment process Spanish language translation Pollution impacts

Table 2-3: List of Commenters and Comment Topics in Comment Letters on the Draft SREIR (August 2020)

Commenter	**SREIR Topics Addressed in Comment**
Partners, California Communities Against Toxics, California Youth vs Big Oil, Center for Climate Change and Health, Citizens Climate Lobby (Idyllwild Chapter), Citizens' Climate Lobby – Contra Costa County, Clean Water Action, Cleveland National Forest Foundation, Climate 911, Climate Health Now, Coalition for Clean Air, CSEA Chapter 289 (Santa Barbara City College), Defenders of Wildlife, Ecumenical Peace Institute/Clergy and Laity Concerned, Environmental Working Group, Food & Water Watch, Fossil Free California, FracTracker Alliance, FreshWater Accountability Project, Friends of the Earth, Good Neighbor Steering Committee, Greenpeace USA, HEalthers for Climate Justice LA, Indivisible Beach Cities, Indivisible South Bay Los Angeles, Interface Climate Action Network of Contra costa County, LA Forward, Los Padres Forest Watch, Marin Interfaith Climate Action, Mothers Out Front Capital Region, Mothers Out Front San Diego, Mothers Out Front San Francisco, Mothers Out Front Silicon Valley, National Parks Conservation Association, Oil Change International, Peak Plastic Foundation, Planning and Conservation League, Ravi and Naina Patel Foundation, Rootskeeper, Safe Energy Now North County, San Diego 350, Santa Barbara Standing Rock Coalition, SEE-LA (Social Eco Education-LA), SoCal 350 Climate Action, St. Mary Magdalen Parish Peace and Justice Committee, Stand.earth, Sunflower Alliance, Surfrider Foundation, Tekia, The Climate Center, The Last Plastic Straw, The Story of Stuff Project, Women's March Santa Barbara *Letter September 16, 2020*	
Earthjustice, Center for Biological Diversity, Center on Race, Poverty & the Environment, Comité Progreso de Lamont, Comité de Lost Hills en Acción, Committee for a Better Shafter, Committee for a Better Arvin, Sierra Club, Greenfield Walking Group, National Resources Defense Council *Letter August 12, 2020* *Letter September 16, 2020* *Letter October 2, 2020*	*Inadequate review time* *Spanish language translation* *Ministerial permitting* *Air impact analysis and mitigation* *Cumulative health risk assessment* *Setback requirements* *Water supply analysis and mitigation* *Alternatives analysis* *Changed circumstances* *Significant new information* *Disparate impacts to Hispanic/Latinx community* *Impacts from livestock grazing* *Flawed San Joaquin Valley Air Pollution Control District Emission Reduction Credit Program* *Inadequate setbacks* *Mitigation for greenhouse gas impacts*

Table 2-3: List of Commenters and Comment Topics in Comment Letters on the Draft SREIR (August 2020)

Commenter	**SREIR Topics Addressed in Comment**
	Oil spill impacts ***Attached Reports:*** *Air quality* *Health Risk Assessment* *Setback distances in other jurisdictions*
Kern County Cattlemen's Association *Letter August 24, 2020*	*Analysis of Impacts to Farmland*
Sequoia Riverlands Trust *Letter September 1, 2020*	*Agricultural conversion mitigation*
Shute, Milhaly, & Weinberger – Representing King and Gardiner Farms, LLC *Letter September 16, 2020*	*Agricultural conversion mitigation* *Water impacts* *Cumulative Health Risk Assessment* *Noise* *Other impacts* ***Attached Reports:*** *Agricultural mitigation/clustering* *Noise* *Air*
WSPA *Letter October 14, 2020*	*Water Supply*

Table 2-4: Comments Received During Virtual Public Workshop

My name is Gustvo Aguirre with Center on Race Poverty & the Environment. The California Council of Science and Technology recommended that all oil and gas wells be located at least 2,500 feet from homes, schools and hospitals to protect environment and public health. Yet the draft EIR does not require any setback distance between oil and gas wells and sensitive receptors. Is the county going to consider requiring a 2,500-foot buffer between new wells and sensitive receptors?
Mi nombre es Estela Escoto soy residente de Arvin. Tambien soy president del Comite por un Arvin Mejor. Arvin esta rodeado de posos de aceite y gas, y yo vivo a menos de 1 milla de posos de aceite. Como persona que solo habla espanol, yo no he podido participar completamente en esta junta por que el condado se reusa a traducir toda la junta al espanol aunque el condado ya contrato a un intérprete para traducir las preguntas del español al ingles. Traducirá el condado documentos claves al espanol? Para que nosotros realmente podamos entender los impactos de 67,000 posos de gas y aceite en el ambiente y la salud de las familias? Tambien, el Departamento de Planificacion conducira procesos para permitir una participacion significante del publico que permita que personas, incluyendo las de habla hispana podamos dar comentarios verbalmente en adición a las audiencias cuando ustedes se les requiere hacerlo? **Comment Translation - My name is Estela Escoto. I am a resident of Arvin. I'm also president of the Committee for a better Arvin. Arvin is surrounded by oil and gas wells, and I live less than 1 mile from oil wells. As a Spanish speaking-only person, I have not been able to fully participate in this meeting because the county refuses to translate the entire meeting into Spanish even though the county already hires an interpreter to translate questions from Spanish to English. Will the county translate key documents into Spanish? So that we can really understand the impacts of 67,000 gas and oil wells on the environment and the health of families? Also, the planning department will conduct processes to allow significant public engagement that allows individuals, including Spanish-speaking people, to give verbal comments in addition to the hearings when you are required to do so?*
Yo vivo a solo unas millas de los pozos de aceite, gas y refinerias. Como persona que hablo ingles limitado no he podido participar en este proceso porque el condado se ha reusado a usar interprete para traducir las preguntas en español al ingles y traducir todas las juntas completas de este tema al español. Traducira el condado documentos claves al español para que podamos entender los impactos de 67,000 pozos de gas y aceite en el ambiente y la salud de las familias? El Departamento de Planificacion conducira procesos para permitir una participacion significante del publico que permita que personas, incluyendo las de habla hispana podamos dar comentarios verbales en adiccion a las audencias cuando ustedes se le requiere hacerlo? **Comment Translation - I live just a few miles from oil, gas wells and a refinery. As a person who speaks limited English I have not been able to participate in this process because the county has been refused to use interpreters to translate the questions in Spanish into English and translate all the full meetings of this topic into Spanish. Will the county translate key documents into Spanish so that we can understand the impacts of 67,000 gas and oil wells on the environment and the health of families? Will the planning department conduct processes to allow significant participation of the public that allows people, including Spanish-speaking people, to give verbal comments at a hearing when you are required to do so?*

Table 2-4: Comments Received During Virtual Public Workshop

Soy residente de Lamont y Presidente del Comite Progreso de Laont. Mi comunidad esta rodeada de pozos de aceite, gas y una refineria, yo vivo a solo millas de los pozos de aceite y la refineria. Porque el condado esta proponiendo inyectar agua contaminada de aceite en los mantos aquiferos subterraneos, cuando muchisima gente dependemos del agua subterranea para beber? **Comment Translation - I am a resident of Lamont and Chairman of the Lamont Progress Committee. My community is surrounded by oil, gas wells and a refinery, I live just miles from the oil wells and the refinery. Why is the county proposing to inject oil-contaminated water into underground aquifer mantle, when many people depend on underground water to drink?*
How would the CPU Alternative function?
My name is Gustavo Jr. Aguirre, and I am with the Central California Environmental Justice Network. Kern County is already in a region that is not meeting federal or state air quality standards for $PM_{2.5}$, PM_{10}, and ozone. Yet this project will emit more than 1,000 tons of $PM_{2.5}$ every year for more than two decades, not to mention other deadly pollutants and greenhouse gases. How will the County reduce the Project's air pollution impact to below significant levels?
On behalf of the applicants WSPA and CIPA, we strongly support the SREIR, prepared by County staff to comply with the court of appeal's decision requiring further environmental analysis of specific impacts. We look forward to completion of the SREIR and reinstatement of the County's highly successful permitting program, which provides environmental protections through rigorous conditions and mitigation measures, while providing industry with the certainty and efficiency of a streamlined process.
Mi nombre es Anabel Marquez yo soy residente de Shafter. Yo soy la presidenta de Un Comite de Un Shafter Mejor. Mi comunidad esta rodeada de aciete y de posos petroleros, yo vivo menos de pocas milas de poso de petrolio. Porque el condado propone de continuar usando las aguas negras de petrolio para regar los campos agricolas? y tambien porque el condado propone que "reciclen" la agua negra de los aceties petroleros para que nuestra famila consuma esa agua sucia? **Comment Translation - My name is Anabel Marquez, I'm a resident of Shafter. I'm the president of A Better Shafter Committee. My community is surrounded by oil fields and oil wells. I live less than a few miles of the oil wells. Why does the county propose to continue using oil waste water, oil water to irrigate the agricultural fields? and also why does the county propose to "recycle" the black water of oil so that our family consumes that dirty water?*

Note:
**- The comment was received in Spanish and translated to English during the Virtual Workshop by County Staff using Google Translate.*

2.5 Availability of the Draft Supplemental Recirculated Environmental Impact Report *(OCTOBER 2020)*

The SREIR *(August 2020) and this SREIR (October 2020) are* ~~is~~ being distributed directly to agencies, organizations, and interested groups and persons for comment during a 45-day formal review period, in accordance with Section 15087 (Public Review of DEIR) of the State CEQA

Guidelines. This SREIR and the full administrative record for the Project, including all studies, are available for review during normal business hours, Monday through Friday, at the Kern County Planning Department, by appointment, located at:

Kern County Planning and Natural Resources Department
2700 M Street, Suite 100
Bakersfield, California 93301-2370
Contact: Cindi Hoover
Phone: (661) 862-8629, Fax: (661) 862-8601
hooverc@kerncounty.com

2.6 Format and Content

In compliance with the Appellate Court opinion, this SREIR addresses the following issues to provide analysis on the five CEQA deficiencies in the 2015 FEIR identified by the Appellate Court:

(1) Mitigation of water supply impacts. Consistent with the opinion, the SREIR will consider feasible revisions to water supply Mitigation Measures (MM) 4.17-2 to 4.17-4 in the 2015 FEIR, or new feasible measures, that would reduce the Project's impacts on regional water supplies, such as by using additional amounts of oil and gas produced water to meet regional irrigation or other applicable water demand. The SREIR's analysis of regional water supply impacts will be brought up to date and include available information developed in conjunction with the implementation of the Sustainable Groundwater Management Act in the Project Area as discussed in the opinion.

(2) Impacts from $PM_{2.5}$ emissions. Consistent with the opinion, the SREIR analyzes potential Project impacts from $PM_{2.5}$ emissions (particles up to 2.5 microns in diameter), consider feasible mitigation measures for reducing potentially significant impacts, and, if applicable, discuss whether such impacts can be feasibly mitigated. The analysis will provide updated information concerning the Project Area's air quality attainment status for $PM_{2.5}$ emissions as discussed in the opinion.

(3) Mitigation of conversion of agricultural land. The opinion determined that farmland impacts are not mitigated by the use of agricultural conservation easements such as included in MM 4.2-1 of the 2015 FEIR. Accordingly, the SREIR will consider other feasible farmland conversion mitigation measures that would reduce the Project's farmland conversion impacts, such as well clustering, as discussed in the opinion. Consistent with the opinion, the SREIR will also consider whether the 2015 FEIR baseline for agricultural resources should be updated.

(4) Noise impacts. Consistent with the opinion, the SREIR analyze potential impacts from an increase in permanent and temporary ambient noise levels attributable to the Project's operational and construction activities, consider feasible mitigation measures for reducing potentially significant impacts, and, if applicable, discuss whether such impacts can be feasibly mitigated. The analysis will also consider whether the 2015 FEIR baseline for noise should be updated as discussed in the opinion.

(5) Recirculation of the Multi-Well Health Risk Assessment for public review and comment. The SREIR will include a Multi-Well Health Risk Assessment for public review and comment and will consider whether the assessment should be revised to reflect updated $PM_{2.5}$ information, as discussed in the opinion.

Additional review has been applied to mitigation measures to clarify changed names of agencies, mitigation that has already been implemented, reflection of changes in law, and clarification of ministerial implementation. This clarifying analysis and proposed mitigation measure language can be found in Section 4.18, Supplemental Analysis.

2.6.1 Required Supplemental Recirculated Environmental Impact Report Contents

This SREIR includes all of the sections required by CEQA. Table 2-3 contains a list of sections required under CEQA, along with a reference to the chapter in which they can be found in this document.

Table 2-3: Required Environmental Impact Report Contents

Requirement (CEQA Section)	Location in SREIR
Table of Contents (Section 15122)	Table of Contents
Summary (Section 15123)	Chapter 1
Issues to be Resolved (Section 15123(b))	Chapter 2
Project Description (Section 15124)	Chapter 3
Environmental Setting (Section 15125)	Chapter 4
Significant Environmental Impacts (Section 15126.2)	Chapter 4
Mitigation Measures (Section 15126.4)	Chapter 4
Cumulative Impacts (Section 15130)	Chapter 4
Effects Found not to be Significant (Section 15128)	Chapters 1, 4, and 5
Unavoidable Significant Environmental Impacts (Section 15126.2(b))	Chapters 4 and 5
Significant Irreversible Changes (Section 15126.2(c))	Chapter 5
Growth-Inducing Impacts (Section 15126.2(d))	Chapter 5
Alternatives to the Proposed Project (Section 15126.6)	Chapter 6
Organizations and Persons Consulted (Section 15129)	Chapter 8
List of Preparers (Section 15129)	Chapter 9
References (Section 15148)	Chapter 10

2.6.2 Baseline

The CEQA Guidelines state that "An EIR must include a description of the physical environmental conditions in the vicinity of the project, as they exist at the time the notice of preparation is published, or if no notice of preparation is published, at the time environmental analysis is commenced, from both a local and regional perspective. This environmental setting will normally constitute the baseline physical conditions by which a lead agency determines whether an impact is significant" (CEQA Guidelines 15125(a)). The NOP for this SREIR was published on August 30, 2013. However, "[n]either CEQA nor the CEQA Guidelines mandates a uniform, inflexible rule for determination of the existing conditions baseline. Rather, an agency enjoys the discretion to decide, in the first instance, exactly how the existing physical conditions without the project can most realistically be measured, subject to review, as with all CEQA factual determinations, for support by substantial evidence." (Communities for a Better Environment v. South Coast Air Quality Management District [2010] 48 Cal.4th 310, 327-238 [CBE v. SCAQMD])

For purposes of this SREIR, one component of existing conditions is the current level of oil and gas activity. The existing conditions, with respect to oil and gas activity at the time that the NOP was published, are best represented by activity data from 2012. At the time that the environmental analysis for this SREIR commenced, 2012 was the last year for which complete data were available from California Department of Conservation Division of Oil, Gas, and Geothermal Resources (DOGGR; now called CalGEM) and other regulatory agencies. The year 2012 is a reasonable choice for existing conditions because it reflects the current state of the oilfields in the County, as well as the cumulative technological developments and the regulatory factors that influence activity levels.

CalGEM data from 1985 through 2012 demonstrate wide fluctuations in activity. The number of new well completions in the County dropped from a peak of 3,005 new well completions in 1985 to a low of 730 new well completions in 1992. Since that time, drilling activity gradually increased again, peaking in 2007 with 2,896 wells drilled. In late 2008 through 2009, fluctuating oil prices and general economic conditions resulted in another drop in activity. From 2010 through 2012, activity levels increased again, reaching 2,619 wells drilled in 2012.

As this dataset indicates, oil and gas exploration and production activity has fluctuated considerably over time. The shifts reflect four primary drivers: changes in available technology; available reserves; regulatory requirements; and the price of oil. Many of the oilfields in the County are mature fields that are experiencing declining oil production and increasing production of associated water. In recent decades, drilling and production technologies have steadily advanced, as the industry developed and implemented cost-effective technologies that allowed operators to maintain production levels even as reserves have declined in established oilfields. New technologies are occasionally sudden "breakthroughs," but more often there is a general trend of incremental developments that are gradually adopted by the industry. For example, hydraulic fracturing commenced in California in the 1940s, and the first successful steam flood occurred in 1968, each prompting rapid changes in the industry. But more recent technological changes have spread incrementally. Changes in regulatory requirements (discussed in the "Regulatory Setting" sections of this SREIR and the 2015 FEIR (SREIR Volume 3) also have affected overall industry activity levels, in particular CalGEM requirements on abandonment of idle wells and air emission regulations requiring installation of pollution control equipment and use of cogeneration and electric engines. Data from the 2012 baseline year incorporate all of these technology- and regulation-induced changes in activity.

In the context of an industry that experiences fluctuations and trends, courts have concluded that "the date for establishing baseline cannot be a rigid one. Environmental conditions may vary from year to year and, in some cases, it is necessary to consider conditions over a range of time periods" (CBE v. SCAQMD at 327-28, citing Save Our Peninsula Committee v. Monterey County Bd. of Supervisors [2001] 87 Cal.App.4th 99, 125). "In some circumstances, peak impacts or recurring periods of resource scarcity may be as important environmentally as average conditions" (Save Our Peninsula at 125-26). Moreover, in light of the past fluctuations in activity, an alternative baseline consisting of average activity levels over a range of prior years would tend to underrepresent the amount of activity under existing conditions.

Accordingly, conditions reflected in the 2012 dataset, which was the best available complete dataset at the time, are considered to best represent baseline conditions existing at the time of the 2015 FEIR NOP.

As directed by the Court the baselines for areas of water and specifically the Sustainable Groundwater Management Act basin plans and implementation and analysis of particulate matter less than 2.5 microns ($PM_{2.5}$) emissions have been updated for the most current year of information.

2.6.3 Project Level Supplemental Recirculated Environmental Impact Report

Based on the comprehensive analyses, mitigation measures, and performance standards included in the SREIR and revised ordinance, it is anticipated that in the vast majority of future oil and gas production activities, implementation of the new ordinance will not result in the need for the County, or for responsible agencies with ministerial or discretionary review and approval processes, to prepare additional CEQA documents for individual well or field development proposals. For discretionary approval processes, additional CEQA review would be required only if the criteria for supplemental CEQA review under CEQA Section 21166 are met (14 CCR §§ 15096(e)(3), 15162). Such streamlined permitting is a permissible objective reflecting land use policy decisions within the authority of a county board of supervisors (San Diego Citizenry Group v. County of San Diego, 219 Cal.App.4th 1 [2013]).

Ministerial projects are those where the governmental approval sought requires "little or no personal judgment by the public official as to the wisdom or manner of carrying out the project (and the public official merely applies the law to the facts as presented but uses no special discretion or judgment in reaching a decision" (14 CCR § 15369). CEQA does not apply to ministerial projects (PRC § 21080(b)(l)).

The CEQA Guidelines encourage public agencies to identify, in their implementing regulations or ordinances, the types of projects and actions that are deemed ministerial under the applicable laws and ordinances (14 CCR § 15268(c)). Under the amended Zoning Ordinance, the County's implementation of the Oil and Gas Conformity Review provides a ministerial permitting process for new oil and gas activities that incorporate the mitigation measures and development standards identified in this SREIR.

Because the ordinance incorporates impact avoidance measures and provides a method for determining whether such measures have been met without the exercise of the County's discretion, the ordinance properly sets forth a ministerial permitting process. See Sierra Club v. Napa County Board of Supervisors, 205 Cal. App. 4th 162 (2012) [certain lot line adjustments in ordinance were properly identified as ministerial where the lot line application was required to comply with specified standards]; San Diego Citizenry Group v. County of San Diego, supra [upholding an EIR for a Zoning Ordinance amendment to allow by-right wineries, where the EIR identified impact avoidance measures built into the Zoning Ordinance]; Health First v. March Joint Powers Authority, 174 Cal. App. 4th 1135 (2009) [where a design plan for a development project complied with conditions set forth by specific plan that had been approved pursuant to CEQA, approval of the design plan via a 125-question checklist was ministerial and the project was exempt from CEQA review.]

The proposed Project establishes new procedures and additional compliance requirements for oil and gas exploration, production, and related activities the County. The County's current ordinance currently authorizes "by right" oil and gas activities in certain areas provided that specified requirements are met, and requires conditional use permits in other Zoning Districts. The ordinance amendments strengthen environmental protection mitigation measures and development standards, and add further procedural and notice requirements, for oil and gas activities.

The degree of specificity in this SREIR corresponds to the degree of specificity in the proposed Project, and serves as a "project-level" SREIR for CEQA purposes. For example, for the new ministerial site plan review process for formerly "by right" oil and gas activities, the County will review site plans for compliance with required measures, and once compliance is verified thereafter will issue ministerial permits (e.g., for individual wells), which would not trigger the need for further CEQA review. The County's inspection and enforcement resources are also increased with a mandatory permit fee program.

A project-level SREIR is appropriate for three primary reasons. First, by examining both the broad implications of the ordinance changes and the detailed site-specific impacts, this approach facilitates identification of the most effective development standards and mitigation requirements to be incorporated into the site plan review process. Second, a project-level SREIR allows the Board of Supervisors and the public to be informed by a comprehensive analysis of impacts at the time the Board considers whether and how to modify existing County ordinances. Finally, a project-level SREIR provides responsible agencies with the level of completed CEQA process required to inform and reach final decisions regarding subsequent discretionary approvals and other actions regarding these County oil and gas activities. If the criteria for supplemental CEQA review are triggered for a particular activity regulated by the revised County ordinances, additional CEQA review would be necessary (14 CCR §§ 15096(e)(3), 15162).

The County's long experience with oil and gas exploration and development allows it to identify and analyze reasonably foreseeable actions and impacts associated with the ordinance amendment at a project-level review. Oil exploration, drilling, and production activities have been conducted in Kern County for more than 100 years. In the late nineteenth and early twentieth century, massive oilfields were discovered in the San Joaquin Valley using simple hand-auger drills, followed by rotary drilling rigs. The first commercial oilfield in Kern County, the McKittrick Field, was established in 1898. The Kern River Field near Bakersfield was discovered the following year. By 1903, the Kern River Field had been developed with 800 wells and had produced nearly 17 million barrels of oil. As the industry developed in California, so did the governing state regulatory regimes.

The primary state regulating entity, CalGEM, was established in 1915. The County Zoning Ordinances addressed oil and gas development as early as 1957. Other responsible and trustee agencies also have a long history regulating the activities and infrastructure associated with oil and gas production and development, and both oil and gas technologies, and the laws and regulations affecting that technology (and the oil and gas industry as a whole) continue to evolve. Kern County currently contains approximately 76 active oil and gas production fields, and over 2,500 wells are drilled in the County every year.

In preparing this SREIR, the County has drawn on its own extensive experience with oil and gas development, and has also reviewed information compiled for decades by other public agencies. In addition, oil and gas industry associations representing current producers and future permit applicants provided the County with forecasts of their estimated future well drilling activity. Finally, the designation of Subareas, Tiers, and Core Areas further facilitated the completion of the Project-level analysis included in this SREIR. These detailed classifications, based on environmental characteristics, existing land uses, and existing and planned oil and gas production activities, allow this SREIR to efficiently forecast reasonably foreseeable future development and the location and magnitude of environmental impacts.

2.6.4 State Preemption of Subsurface Oil and Gas Activities

CEQA defines the term "project" to mean the whole of the action that has a potential for resulting in either a direct physical change or a reasonably foreseeable indirect physical change in the environment (CEQA Guidelines § 15378). An EIR must consider potential impacts from the entire project (e.g., CEQA Guidelines §§ 15126, 15126.2). Therefore, this SREIR evaluates all impacts from the proposed ordinance amendments, including the surface and subsurface aspects of future oil and gas activities carried out pursuant to the amended ordinances. However, CalGEM is the state agency responsible for regulating the subsurface operations from oil and gas activities. This SREIR describes CALGEM regulatory requirements, and the regulatory requirements of other agencies, in the "Regulatory Setting" portion of each resource section of the SREIR. The SREIR also describes how applicable regulatory requirements avoid or reduce significant adverse impacts on the environment as relevant to each resource section of the SREIR.

As explained in the CEQA Guidelines, CEQA "supplements" the discretionary power of a lead agency "to mitigate or avoid significant effects on the environment when it is feasible to do so with respect to projects subject to the powers of the agency" (CEQA § 15040(c), emphasis added). The CEQA Guidelines also clarify that CEQA is "intended to be used in conjunction with discretionary powers granted to public agencies by other laws."

Under CEQA, lead agencies may enforce only "feasible" mitigation measures. "Feasibility" is defined in the CEQA Guidelines to include "legal feasibility" (i.e., can the mitigation be lawfully enforced by the lead agency). In general, the County lacks the legal authority to regulate subsurface oil and gas activities. As the California Attorney general has explained:

> State laws on drilling and production activities of oil, gas and geothermal resources wells for the purpose of conserving and protecting those resources take precedence over local regulations, particularly where the State law approves of or specifies plans of operation, methods, materials, procedures, or equipment to be used by the well operator or where activities are to be carried out under direction of the State Supervisor. With regard to state regulation for other purposes, such as land use control and environmental protection, the State has not fully occupied the field, and more stringent, supplemental regulation by cities and counties is valid to the extent that it does not conflict or interfere with state regulation (59 Ops. Cal. Atty. Gen. 461, Opinion No. SO 76-32 [1976]).

The Attorney General further reasoned that "the State has so fully occupied [the underground phases of oil and gas activities] that there is no room left for local regulation" (Id at 477-478). This basic law has not changed over the past 50 years.

With respect to Class II injection wells, the U.S. Environmental Protection Agency (EPA) implements the Underground Injection Control program, but may delegate enforcement responsibility to a state (a designation known as "primacy") (40 Code of Federal Regulations [CFR] Part 145). Therefore, the EPA has delegated primacy for Class II injection wells to the State of California, through CalGEM (48 CFR § 6336 [February 4, 1983], as described in greater detail in Section 4.9, Hydrology and Water Quality). CalGEM's implementing regulations set forth detailed requirements for well design, construction, equipment, ancillary pipelines, and abandonment (14 CCR, Div. 2, Ch. 4). CalGEM's jurisdiction includes the regulation of production wells and "Class II" injection wells under the Underground Injection Control (UIC) Program of the federal Safe Drinking Water Act, 42 United States Code [U.S.C.] § 300f et seq.). The term Class II refers to injection, disposal, and storage wells associated with oil and gas exploration (40 CFR § 144.6). CalGEM issues permits and establishes conditions, including as to the design, construction, and operation, for Class II well activity (14 CCR § 1712 et seq.). In addition, California recently passed SB 4, which directs CalGEM to adopt regulations governing well stimulation treatment activities (PRC § 3150 et seq.). SB 4 regulations similarly address design, construction, and operations.

This SREIR does, however, explain the applicable federal and state legal requirements of other agencies, including CalGEM. Where compliance with these requirements would avoid or lessen a potentially significant environmental impact, this SREIR operates in conjunction with these other requirements to identify these as mitigation measures for EIR purposes. The process for assuring implementation of mitigation measures is described in the Mitigation, Monitoring, and Reporting Program (MMRP); for mitigation measures based on compliance with other regulatory programs, the MMRP provides a mechanism by which the County, in its lead agency role, will work with responsible agencies, such as CalGEM, to track implementation of mitigation measures that require compliance with the regulatory requirements of responsible agencies.

2.6.5 Organization of the Supplemental Recirculated Environmental Impact Report

The content and organization of this SREIR are designed to meet the requirements of CEQA, State CEQA Guidelines, and the Kern County CEQA Implementation Document, as well as to present issues, analysis, mitigation, and other information in a logical and understandable way. This SREIR is organized into the following sections:

- **Chapter 1, Executive Summary,** provides a Project description and a summary of the environmental impacts and mitigation measures.
- **Chapter 2, Introduction,** provides CEQA compliance information, an overview of the decision-making process, organization of the SREIR, and a list of responsible and trustee agencies.
- **Chapter 3, Project Description,** provides a description of the location, characteristics, objectives, and relationship of the Project to other plans and policies.
- **Chapter 4, Environmental Setting, Impacts, and Mitigation Measures,** contains a detailed environmental analysis of the existing conditions, Project impacts, mitigation measures, and unavoidable adverse impacts for the five topical areas - Section 4.2, Agriculture and Forest Resources; Section 4.3, Air Quality; Section 4.9, Hydrology and Water Quality; Section 4.12, Noise; and Section 4.17, Utilities and Service Systems. Section 4.18, Supplemental Analysis, reviews and clarifies, all other topic mitigation measures, if needed.
- **Chapter 5, Consequences of Project Implementation** (Mandatory CEQA Sections)**,** presents an analysis of the Project's cumulative and growth-inducing impacts and other CEQA requirements, including significant and unavoidable impacts and irreversible commitments of resources.
- **Chapter 6, Alternatives,** describes a reasonable range of alternatives to the Project that could avoid or reduce the significant environmental effects of the Project.
- **Chapter 7, Responses to Comments,** is reserved for responses to comments on this SREIR.
- **Chapter 8, Organizations and Persons Consulted,** lists the agencies, organizations, and persons contacted during preparation of this SREIR.

- **Chapter 9, List of Preparers,** identifies persons involved in the preparation of the SREIR.
- **Chapter 10, Bibliography,** identifies reference sources for the SREIR.
- **Chapter 11, Acronyms, Abbreviations, and Glossary,** lists all acronyms, abbreviations, and technical terms mentioned in the SREIR with corresponding definitions.
- **Appendices** provide information and technical studies that support the environmental analysis contained within the SREIR.

The analysis of each environmental category in Chapter 4, Environmental Setting, Impacts, and Mitigation Measures, is organized as follows:

- **"Introduction"** provides a brief overview on the purpose of the resource being analyzed with regard to the Project.
- **"Environmental Setting"** describes the physical conditions that exist at this time and that may influence or affect the resource being analyzed.
- **"Regulatory Setting"** provides state and federal laws, and the Kern County General Plan (KCGP) goals, policies, and implementation measures that apply to the resource being analyzed.
- **"Impacts and Mitigation Measures"** discusses the impacts of the Project in each category, including direct, indirect, and cumulative impacts, presents the determination of the level of significance, and provides a discussion of feasible mitigation measures to reduce any impacts.

2.7 Responsible and Trustee Agencies

Projects or actions undertaken by the lead agency, in this case Kern County, may require subsequent oversight, approvals, or permits from other public agencies in order to be implemented. Other such agencies are referred to as "responsible agencies" and "trustee agencies." Pursuant to Sections 15381 (Responsible Agency) and 15386 (Trustee Agency) of the State CEQA Guidelines, as amended, responsible agencies and trustee agencies are defined as follows:

- A "responsible agency" is a public agency that proposes to carry out or approve a project, for which a lead agency is preparing or has prepared an EIR or Negative Declaration. For the purposes of CEQA, the term "responsible agency" includes all public agencies other than the lead agency that have discretionary approval power over the project (Section 15381).
- A "trustee agency" is a state agency having jurisdiction by law over natural resources affected by a project that are held in trust for the people of the State of California (Section 15386).

The various public, private, and political agencies and jurisdictions with a particular interest in the Project include, but are not limited to, the following:

Federal Agencies

- U.S. Fish and Wildlife Service (USFWS);
- U.S. Army Corps of Engineers (USACE);
- U.S. Environmental Protection Agency (EPA);
- U.S. Department of the Interior, Bureau of Land Management (BLM), Bakersfield Field Office;
- Federal Aviation Administration (FAA); and
- U.S. Department of Agriculture (USDA).

State Agencies

- California Air Resources Board (CARB);
- California Department of Conservation, Geologic Energy Management Division (CALGEM);
- California Department of Fish and Wildlife (CDFW);
- California Department of Public Health;
- California Department of Toxic Substance Control (DTSC);
- California Energy Commission (CEC);
- California Highway Patrol (CHP);
- California Public Utilities Commission (CPUC);
- California Native American Heritage Commission (NAHC);
- California Office of Historic Preservation;
- California State Lands Commission (CSLC);
- Governor's Office of Planning and Research (OPR);
- Regional Water Quality Control Board, Central Valley District (RWQCB); and
- State Water Resources Control Board (SWRCB).

Local Agencies

- San Joaquin Air Pollution Control District (SJAPCD);
- Kern Council of Governments (COG);

- Kern County Public Works Department, Operations Division
- Kern County Public Works Department, Engineering and Surveying Services Division;
- Kern County Fire Department (KCFD);
- Kern County Planning and Natural Resources Department (KCPNR);
- Kern County Public Health Services Department, Environmental Health Division;
- Kern County Public Services Department, Development Review Division;
- Kern County Planning Commission; and
- Kern County Board of Supervisors.

2.8 Incorporation by Reference

In accordance with Section 15150 (Incorporation by Reference) of the State CEQA Guidelines, to reduce the size of the report, the following documents are hereby incorporated by reference into this SREIR and are available for public review at the KCPNR. A brief synopsis of the scope and content of these documents is provided below.

Kern County General Plan

The KCGP is a policy document with planned land use maps and related information and is designed to give long-range guidance to those County officials making decisions affecting the growth and resources of the unincorporated Kern County jurisdiction, excluding the Metropolitan Bakersfield Planning Area. This document, adopted on June 14, 2004, and last amended on September 22, 2009, helps to ensure that day-to-day decisions conform to the long-range program designed to protect and further the public interest as related to the County's growth and development and to mitigate environmental impacts. The KCGP also serves as a guide to the private sector of the economy in relating its development initiatives to the County's public plans, objectives, and policies.

Kern County Zoning Ordinance

According to Chapter 19.02.020, Purposes, Title 19 was adopted to promote and protect the public health, safety, and welfare through the orderly regulation of land uses throughout the unincorporated area of the County. Further, the purposes of this title are to:

- Provide the economic and social advantages resulting from an orderly planned use of land resources;
- Encourage and guide development consistent with the KCGP;
- Divide Kern County into Zoning Districts of a number, size, and location deemed necessary to carry out the purposes of the KCGP and this title;

- Regulate the size and use of lots, yards, and other open spaces;
- Regulate the use, location, height, bulk, and size of buildings and structures;
- Regulate the intensity of land use;
- Regulate the density of population in residential areas;
- Establish requirements for off-street parking;
- Regulate signs and billboards; and
- Provide for the enforcement of the regulations of Chapter 19.02.

2014 Regional Transportation Plan/Sustainable Community Strategy

The 2014 Regional Transportation Plan (RTP)/Sustainable Communities Strategy (SCS), was adopted in 2014 and is a 26-year blueprint that establishes a set of establishes a set of regional transportation goals, objectives, policies, and actions intended to guide development of the planned multimodal transportation systems in the County. The RTP/SCS has been developed through a continuing, comprehensive, and cooperative planning process, and provides for effective coordination between local, regional, state, and federal agencies. New to the 2014 RTP, California's Sustainable Communities and Climate Protection Act, or SB 375, calls for the Kern RTP to include a SCS that reduces greenhouse gas emissions from passenger vehicles and light-duty trucks by 5% per capita by 2020 and 10% per capita by 2035, as compared to 2005. In addition, SB 375 provides for closer integration of the RTP/SCS with the Regional Housing Needs Allocation (RHNA), ensuring consistency between low income housing need and transportation planning. The 2014 RTP/SCS exceeds SB 375 reduction targets for the region and is consistent with the RHNA.

Kern County Airport Land Use Compatibility Plan (2008)

The Kern County Airport Land Use Compatibility Plan (ALUCP) was originally adopted in 1996 and has since been amended to comply with Aeronautics Law, Public Utilities Code (Chapter 4, Article 3.5) regarding public airports and surrounding land use planning. As required by that law, proposals for public or private land use developments that occur within defined airport influence areas are subject to compatibility review. The principle airport land use compatibility concerns addressed by the ALUCP are: (1) exposure to aircraft noise; (2) land use safety with respect to both people and property on the ground and the occupants of aircraft; (3) protection of airport air space; and (4) general concerns related to aircraft overflights.

The ALUCP identifies policies and compatibility criteria for influence zones or planning area boundaries. The ALUCP maps and labels these zones as A, B1, B2, C, D, and E, ranging from the most restrictive (A – airport property runway protection zone) to the least restrictive (D – disclosure to property owners only), while the E zone is intended to address special land use development. As required by law, the following affected cities have adopted the ALUCP for their respective airports: Bakersfield, California City, Delano, Shafter, Taft, Tehachapi, and Wasco.

County of Kern Housing Element (2008–2013)

The development and preservation of adequate and affordable housing is important to the well-being of the residents and the economic prosperity of the County. To plan for the development of adequate housing for all income segments, a housing element was prepared as a part of the KCGP. This document constitutes the Housing Element, which specifically addresses housing needs and resources in the County's unincorporated areas. The Housing Element must maintain consistency with the other elements of the KCGP.

2.9 Sources

This SREIR is dependent upon information from many sources including the 2015 FEIR. Some sources are studies or reports that have been prepared specifically for this document. Other sources provide background information related to one or more issue areas that are discussed in this document. The sources and references used in the preparation of this SREIR are listed in Chapter 10, Bibliography, and are available for review by appointment during normal business hours at the:

Kern County Planning and Natural Resources Department
2700 "M" Street, Suite 100
Bakersfield, California 93301-2370
Contact: Cindi Hoover, Lead Planner
hooverc@kerncounty.com

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Chapter 3

Project Description

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Chapter 3
Project Description

3.1 Project Overview

Kern County, California (County), is one of the richest oil-producing counties in the United States. The valley floor area of the County and the lower elevations of the surrounding mountain ranges contain numerous deposits of oil and gas resources, a major economic resource for the County.

Oil and natural gas exploration and extraction has occurred for more than 100 years in California, and specifically in Kern County. In 2012, Kern County produced 80% of the on-shore oil and gas produced in California. In 2012 and 2013, California produced 197.5 and 199.6 million barrels of oil annually, respectively, making California the third largest state in terms of daily production (DOGGR 2014b).

The proposed Project is the reconsideration of revisions to Title 19 of the Kern County Zoning Ordinance - 2020-A (Ordinance) for local permitting for oil and gas focused on Chapter 19.98 (Oil and Gas Production), to address oil and gas exploration and operation activities in greater detail by: (a) establishing updated development, implementation standards, and conditions to address environmental impacts of pre-drilling exploration, well drilling, and the operation of wells and other oil and gas production-related equipment and facilities, including exploration, production, completion, stimulation, reworking, injection, monitoring, and plugging and abandonment; and (b) establishing new "Oil and Gas Conformity Review" and "Minor Activity Review" ministerial permit procedures for County approval of future well drilling and operations to ensure compliance with the updated development and implementation standards and conditions and provide for ongoing tracking and compliance monitoring.

In 2012, representatives of the oil and gas industry associations—specifically, the California Independent Petroleum Association (CIPA), the Independent Oil Producers Agency (IOPA), and the Western States Petroleum Association (WSPA), (collectively, "Project Proponents")—requested an amendment to Chapter 19.98 (Oil and Gas Production) and related chapters of the Kern County Zoning Ordinance to include additional provisions for local permitting of oil and gas activities. Under Chapter 19.112, amendments to the text of the Zoning Title of the Kern County Zoning Ordinance can only be initiated by the Kern County Board of Supervisors. The request was considered in a public hearing before the Board of Supervisors on January 22, 2013, and the Board directed the Staff of the Planning and Community Development Department (now renamed the Planning and Natural Resources Department) to proceed with processing the requested amendments. After a public process of workshops, circulation of the Notice of Preparation and Draft Environmental Impact Report (EIR) and consideration at a noticed Planning Commission hearing with a recommendation to the Board for adoption, on November 9, 2015, Kern County (County) certified a Final EIR (referred to herein as the 2015 FEIR) and approved the proposed

Ordinance revisions as amendments to Title 19 and other related ordinances for local oil and gas permitting.

With the adoption of the amendments in 2015, it became a mandatory requirement that any new well, rework, well stimulation, or pipeline, as well as changes to existing facilities, now needed a permit first from the Kern County Planning and Natural Resources Department before applying to California Geologic Energy Management Division (CalGEM) for a permit. The ordinance became effective on December 9, 2015, and ended March 25, 2020, at midnight.

Beginning in December 2016, an annual report has been prepared and filed on the agenda with the Kern County Board of Supervisors as well as posted on the department website. https://kernplanning.com/planning/kern-county-oil-gas-permitting-3-2/. The Department's Oil and Gas Permitting Division managed the program through an online portal (Accela) program linked to the Building Inspection Division and other Planning functions. Various materials were prepared to assist applicants in submitting complete, compliant applications, including the Permitting Handbook and Small Producers Handbook. The annual reports contained the statistics for the program since commencement on December 9, 2015. Under the court order, the department ended processing any permits on March 25, 2020. The following is a summary of the permitting done under the 2015 FEIR.

Table 3-1: Total Approved and Issued Permits

Permit Type	**Issued**					
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Oil and Gas Conformity Review	1,122	1,891	1,055	1,208	585	5,861
Minor Reworks	N/A	399	903	880	432	2,614
Minor Activity Review	72	105	151	177	117	622
TOTAL	1,194	2,395	2,109	2,265	1,134	9,097

Table 3-2: Mitigation Funds From Approved Permits

Mitigation Measure	FEE CODE	AMOUNT					
		2016	2017	2018	2019	2020	Total
4.16-1	POG050 – Roadway Maintenance/Improvements	$388,700.00	$1,444,500.00	$2,805,000.00	$2,769,000.00	$2,122,500.00	$9,529,700.00
4.14-1	POG051 – Firefighting Equipment	$162,450.00	$380,700.00	$299,550.00	$47,026.00	-	$889,726.00
4.5-3	POG052 – Paleontological Resource	$10,300.00	$37,950.00	$61,800.00	$59,200.00	$33,525.00	$202,775.00
4.14-2	POG053 – Rural Crimes Unit	$432,225.00	$1,065,050.00	$1,427,575.00	$1,312.975.00	$691,819.60	$4,929,644.60
Done 4.2-1	POG054 - Mitigation of Agricultural Land Replacement	$30,996.00	$20,817.00	$66,247.67	$28,242.00	-	$146,302.67
4.3-8	POG055 - Air Quality Impacts	$3,329,332.87	$14,443,711.93	$32,268,388.27	$38,896,506.00	$25,161,192.61	$114,099,131.68
4.3-8	POG057 – SJVAPCD Fee	$138,722.20	$584,744.32	$1,301,032.45	$1,554,270.00	$991,502.98	$4,570,271.95
4.4-16	POG056 - Biological Resources Mitigation	$60,502.50	$349,985.29	$431,815.40	$505,495.00	$362,193.94	$1,709,992.13
	Total	$4,553,228.57	$18,327,458.54	$38,661,408.79	$45,172,714.00	$29,362,734.13	$136,077,544.03

Several parties filed lawsuits challenging the adequacy of the certified 2015 FEIR, and the cases were consolidated in the Kern County Superior Court. On April 20, 2018, the Court issued a judgment upholding the 2015 FEIR in its entirely except for requiring supplemental environmental review under the California Environmental Quality Act (CEQA) except for two issues. The judgment did not vacate any portion of the Ordinance or the 2015 FEIR. The County subsequently prepared and circulated a Draft Supplemental Environmental Impact Report (SEIR) in response to the judgment. The SEIR was certified by the County Board of Supervisors on December 11, 2018, and was not legally challenged.

Several parties appealed the judgment to the Fifth Appellate District of the California Court of Appeal (Appellate Court). In October 2019, the Appellate Court rejected certain constitutional claims against the Ordinance amendments. On February 25, 2020, the Appellate Court issued an opinion that upheld the judgment and the adequacy of the certified 2015 FEIR except for "five areas in which the EIR did not comply with CEQA: (1) mitigation of water supply impacts; (2) impacts from PM2.5 emissions; (3) mitigation of conversion of agricultural land; (4) noise impacts; and (5) recirculation of the Multi-Well Health Risk Assessment for public review and comment." The opinion directed the Superior Court to set aside the certification of the 2015 FEIR and the previously approved Ordinance amendments, effective March 25, 2020. The opinion states that "pending CEQA compliance, the County will return to the regulatory scheme in place prior to the ordinance's adoption." The opinion further directs the County, "in the event it decides to present the Ordinance (in its present or a modified form) to the Board for approval, to correct the CEQA violations identified in this opinion," to prepare "a revised EIR correcting the CEQA violations," and to prepare and publish "responses to the comments received before certifying the revised EIR and reapproving the Ordinance." Under order of the court, the Kern County Board of Supervisors on May 19,2020, rescinded Title 19 Ordinance for Local Oil and Gas Permitting (2015-C) and decertified the 2015 FEIR (Board Resolution 2020-116).

The purpose of this Supplemental Recirculated Environmental Impact Report (SREIR) is to provide analysis to address the CEQA deficiencies found by the Appellate Court decision and provide compliance for CEQA for the reconsideration by the Planning Commission and Board of Supervisors of the Zoning Ordinance revisions focused on Oil and Gas Local Permitting.

This revision of the Zoning Ordinance for local permitting also requires that other relevant references in the Zoning Ordinance be reviewed and revised for consistency. Section 3.4.1, below, describes the text changes to the Zoning Ordinance, and the complete listing of all the text changes to the Zoning Ordinances (collectively, "Amended Zoning Ordinance") as proposed and analyzed in this SREIR are appended to the end of this chapter in Attachment A. The Amended Zoning Ordinance, together with the implementation of future oil and gas activities expected to be undertaken pursuant to the Amended Zoning Ordinance, is the "Project" considered in this SREIR (hereafter referred to as the "Project"). The development standards and conditions contained in the Zoning Ordinance modifications would apply throughout the unincorporated County. However, for purposes of this SREIR, the "Project Area" is defined as the portion of unincorporated Kern County that is depicted in Figure 3-1. The Project Area represents the geographic scope of foreseeable environmental impacts from the Project in the oil and gas producing zones of the County, primarily consisting of the Valley Floor area. In the unlikely event that oil and gas production activities are proposed outside the defined Project Area, supplemental environmental review under CEQA would be required.

This SREIR has been prepared to identify and evaluate potential environmental impacts associated with future oil and gas exploration, development, and production activities in the Project Area expected to be undertaken pursuant to the Amended Zoning Ordinance.

The Board of Supervisor's referral to the Kern County Planning and Community Department of the proposed Project would amend the Kern County Zoning Ordinance to include additional provisions to protect human health and safety and the environment as part of the permitting process for oil and gas activities under the jurisdiction of the Kern County.

Kern County has determined that consideration of the Amended Zoning Ordinance requires a project-level EIR under CEQA, with Kern County as the Lead Agency, to cover implementation of the Project for the future Kern County oil and gas exploration and production activities described below. The impact and mitigation analysis conducted for the 2015 Final Environmental Impact Report (2015 FEIR), the 2018 SEIR, and this SREIR has also resulted in the inclusion, into the amended text of the ordinance, of development standards and conditions, including required implementation of applicable mitigation measures for oil and gas activities, which will allow for a streamlined surface use permitting process for oil and gas activities.

As described in Chapter 2, Introduction, the Kern County Planning Commission and Board of Supervisors will consider the information in this SREIR, including public comments and staff responses to those comments, during the public hearing process. As approval of amended ordinances is a legislative action, the final decision will be made at the Board of Supervisors' public hearing, where the Project may be approved, conditionally approved, or denied.

This SREIR will also be utilized by state, regional, and local agencies and departments with discretionary approval authority for some component of the oil and gas activities covered by this SREIR (Responsible Agencies). The primary Responsible Agencies for oil and gas activities in Kern County are:

- CalGEM, which oversees surface and subsurface operations of oil, gas, and injection wells; well exploration, drilling, and construction; well testing; well completion, stimulation, and workovers; oil and gas operations and maintenance; and well removal, plugging, and abandonment. CalGEM is completing a programmatic EIR for statewide well stimulation activities, as required by Senate Bill (SB) 4 (Pavley). However, this SREIR, which is not limited to well stimulation, is broader in scope and independent of, not "tiered" under, CalGEM's SB 4 EIR. This SREIR provides project-level CEQA coverage on which CalGEM can rely, as a Responsible Agency, for permitting of oil and gas activities, including well stimulation treatment, in the Project Area within Kern County.

- The San Joaquin Valley Air Pollution Control District (SJVAPCD), which oversees air quality permitting, as well as regional air quality planning and regulatory programs to attain regional and localized ambient air quality standards. While the SJVAPCD does not issue individual permits for wells, it oversees permitting for oil- and gas-related equipment/facilities, including boilers, steam generators and process heaters, flares, tanks, and portable equipment. In addition, the SJVAPCD permits thermally enhanced oil recovery operations. This SREIR provides project-level CEQA coverage for most future oil and gas air permits issued by the SJVAPCD, and also requires additional air quality mitigation for oil and gas activities pursuant to a new Voluntary Emission Reduction Agreement, as described in Section 4.3, Air Quality. This SREIR does not provide CEQA coverage for new or expanded cogeneration facilities, which likely would not be required as part of the Project.

- The Central Valley Region of the Regional Water Quality Control Board (CVRWQCB) oversees permitting for discharges of wastewater and stormwater, as well as water basin planning and regulatory programs to attain and maintain compliance with applicable water quality standards and objectives. The CVRWQCB is responsible for permitting discharge of produced water to percolation and evaporation ponds, drilling sumps, and wastewater disposal sumps, through issuance of waste discharge requirements (WDRs), or other forms of discharge authorization such as Clean Water Act Section 401 water quality certification and WDR waivers. In addition, the CVRWQCB also oversees the cleanup of petroleum-related spills and releases, as well as spills and releases of other chemicals. This SREIR provides project-level CEQA coverage for future oil and gas WDRs or other water quality authorizations, and basin plan amendments for oil and gas activities in Kern County, including discharges of stormwater, produced water, and well stimulation fluids, and wastewater treatment, storage, and disposal activities. This SREIR does not provide project-level CEQA coverage for specific remediation activities requiring CVRWQCB approval (e.g., either offsite removal, onsite treatment, or onsite capping and management) for accidental spills or releases of petroleum or hazardous substances from oil and gas activities.

- The California Department of Fish and Wildlife (CDFW) oversees permitting for activities that could result in the incidental take of protected wildlife and plant species, as well as regional and sub-regional habitat conservation planning and permitting, and serves as the natural resources trustee under CEQA. The CDFW is also responsible for the conservation, protection, and management of fish, wildlife, and native plant resources under the lake and streambed alteration program. This SREIR provides project-level CEQA coverage for CDFW permits and approvals, including incidental take permits and habitat conservation plan and natural community plans, for oil and gas activities in Kern County. Several such permits and plan approval applications are pending before the CDFW, including, for example, habitat conservation plans and related CDFW approvals for Lokern and Elk Hills, as described in further detail in Section 4.4, Biological Resources. This SREIR does not provide project level CEQA coverage for site specific remediation activities (described above), or for habitat enhancement, or restoration activities (described above), other than oil and gas activities, that occur in the San Joaquin Valley, and that may also require permits or approvals from the CDFW.

- The California Department of Toxic Substances Control (DTSC) oversees hazardous waste management, as well as the cleanup of non-petroleum spills and releases. This SREIR provides project-level CEQA coverage for the routine management of hazardous substances and wastes, but does not provide CEQA coverage for remediation activities (described above), or for new solid or hazardous waste landfills.

- The California Department of Resources Recycling and Recovery (CalRecycle) oversees certain types of solid waste management and recycling programs. This SREIR does not provide CEQA coverage for new or expanded solid waste landfills for solid wastes generated by oil and gas activities; no such new or expanded landfills would be anticipated as part of the Project.

- The California Department of Transportation (Caltrans) oversees construction and maintenance of state highways. While no new or expanded state highway facilities would be anticipated as part of the Project, Caltrans may issue encroachment permits for ancillary facilities, such as pipelines/distribution lines and pipe bridges. This SREIR provides project-level CEQA coverage for such encroachment permits.

- The Central Valley Flood Protection Board (CVFPB) administers activities affecting designated floodways, including Kern River and the Outlet Canal/Buena Vista Slough. These features bisect several oil and gas fields, and the CVFPB may issue encroachment permits for ancillary facilities, such as pipelines/distribution lines and pipe bridges. This SREIR provides project-level CEQA coverage for such encroachment permits.

- The Kern County Water Agency and other water districts, in the Project Area oversee the distribution and use of surface and groundwater resources in the Project Area. Although almost all water produced, used, and disposed of by the oil and gas industry is from the same geologic formation that contains oil and gas, additional water is used, treated, re-used, and/or disposed of, as discussed in Section 4.9, Hydrology and Water Quality, and Section 4.17, Utilities and Service Systems. This SREIR provides project-level CEQA coverage for these ongoing water-related uses, but does not provide CEQA coverage for new diversions or distributions of local surface waters for uses not addressed in Section 4.9, Hydrology and Water Quality.

This SREIR may also be used as an informational resource by other federal, state, and local agencies. For example, federal agencies are encouraged to use CEQA documents as part of the National Environmental Policy Act review process for federally regulated activities, such as the potential for incidental take of, and habitat conservation planning for, federally protected species, as regulated by the U.S. Fish and Wildlife Service (USFWS); the discharge of dredged materials or fill into federally jurisdictional waters, as permitted by the U.S. Army Corps of Engineers; compliance with applicable federal standards and requirements for air and water quality, waste and wastewater management, and cleanup of contamination as overseen by the U.S. Environmental Protection Agency (EPA); protection of archaeological and historic resources by the State Historic Preservation Office; oversight of certain floodplain activities by the Federal Emergency Management Agency; and management of, and access to, federal lands and mineral resources within Kern County by the U.S. Department of Interior, Bureau of Land Management (BLM).

Federal and state agencies that are not Responsible Agencies but engage in planning or management activities that could be informed by the Project may use this SREIR, including, for example, the California Department of Water Resources, Bureau of Reclamation, and related entities in the management of surface water supplies from the Sacramento Delta, which has historically supplied a small portion of the water used by the oil and gas industry; the Native American Heritage Commission, which coordinates consultation with tribal representatives; and the Kern County Council of Governments, which coordinates certain federal highway and transportation funding activities and engages in regional transportation and greenhouse reduction planning. Local agencies, including but not limited to cities and districts located within outer boundaries of the Project Area, may also use the information included in this SREIR for local planning and other activities.

3.1.1 Revisions to Title 19 - Kern County Zoning Ordinance (2020 -A) and Related Changes

The proposed 2020 revisions to Title 19 – Kern County Zoning Ordinance are the same as the ordinance adopted by the Board of Supervisors November 09, 2015, and implemented until March 25, 2020, with the exception of the following changes:

- Update of names of County departments and State agencies that have changed since 2015, reference to this SREIR, and implementation details
- Clarification of process for monitoring Split Estate 120-day process; and
- Adjustment of Tier Maps for technical geographic information system (GIS) errors identified from 2015 adoption.

3.1.2 Supplemental Recirculated Environmental Impact Report New and Updated Analysis

The purpose of the SREIR is to provide analysis to address the five CEQA deficiencies in the Project's 2015 FEIR that were identified in the Appellate Court opinion issued on February 25, 2020. The County Board of Supervisors previously adopted the proposed Ordinance amendments and certified an FEIR on November 9, 2015. Several parties filed lawsuits challenging the adequacy of the certified FEIR, and the cases were consolidated in the Kern County Superior Court. On April 20, 2018, the Court issued a judgment upholding the 2015 FEIR except for two issues. The judgment did not vacate any portion of the Ordinance or the 2015 FEIR. The County subsequently prepared and circulated a Draft SEIR (2018 SEIR) in response to the judgment. The 2018 SEIR was certified by the County Board of Supervisors on December 11, 2018, and was not legally challenged.

Several parties appealed the Superior Court judgment. In October 2019, the Appellate Court rejected constitutional claims against the Ordinance amendments. On February 25, 2020, the Appellate Court issued an opinion that upheld the Superior Court judgment and the adequacy of the certified 2015 FEIR except for "five areas in which the EIR did not comply with CEQA: (1) mitigation of water supply impacts; (2) impacts from $PM_{2.5}$ emissions; (3) mitigation of conversion of agricultural land; (4) noise impacts; and (5) recirculation of the Multi-Well Health Risk Assessment for public review and comment." The opinion set aside the previously approved Ordnance amendments and the certification of the 2015 FEIR. The opinion further directs the County, "in the event it decides to present the Ordinance (in its present or a modified form) to the Board for approval, to correct the CEQA violations identified in this opinion," to prepare "a revised EIR correcting the CEQA violations" and to prepare and publish "responses to the comments received before certifying the revised EIR and reapproving the Ordinance."

In compliance with the Appellate Court opinion, the County will prepare and circulate an SREIR that will address the following issues to provide analysis on the five CEQA deficiencies in the 2015 FEIR identified by the Appellate Court:

(1) Mitigation of water supply impacts. Consistent with the opinion, the SREIR will consider feasible revisions to water supply Mitigation Measures (MM) 4.17-2 to 4.17-4 in the 2015 FEIR, or new feasible measures, that would reduce the Project's impacts on regional water supplies, such as by using additional amounts of oil and gas produced water to meet regional irrigation or other applicable water demand. The SREIR's analysis of regional water supply impacts will be brought up to date and include available information developed in conjunction with the implementation of the Sustainable Groundwater Management Act (SGMA) in the Project Area as discussed in the opinion.

(2) Impacts from $PM_{2.5}$ emissions. Consistent with the opinion, the SREIR will analyze potential Project impacts from $PM_{2.5}$ emissions (particles up to 2.5 microns in diameter), consider feasible mitigation measures for reducing potentially significant impacts, and, if applicable, discuss whether such impacts can be feasibly mitigated. The analysis will provide updated information concerning the Project Area's air quality attainment status for $PM_{2.5}$ emissions as discussed in the opinion.

(3) Mitigation of conversion of agricultural land. The opinion determined that farmland impacts are not mitigated by the use of agricultural conservation easements such as included in MM 4.2-1 of the 2015 FEIR. Accordingly, the SREIR will consider other feasible farmland conversion mitigation measures that would reduce the Project's farmland conversion impacts, such as well clustering, as discussed in the opinion. Consistent with the opinion, the SREIR will also consider whether the 2015 FEIR baseline for agricultural resources should be updated.

(4) Noise impacts. Consistent with the opinion, the SREIR will analyze potential impacts from an increase in permanent and temporary ambient noise levels attributable to the Project's operational and construction activities, consider feasible mitigation measures for reducing potentially significant impacts, and, if applicable, discuss whether such impacts can be feasibly mitigated. The analysis will also consider whether the 2015 FEIR baseline for noise should be updated as discussed in the opinion.

(5) Recirculation of the Multi-Well Health Risk Assessment for public review and comment. The SREIR will include a Multi-Well Health Risk Assessment for public review and comment and will consider whether the assessment should be revised to reflect updated $PM_{2.5}$ information, as discussed in the opinion.

Consistent with the opinion, the County will prepare and publish responses to comments on the SREIR prior to the consideration by the Planning Commission and Board of Supervisors of the Final SREIR and proposed Amended Zoning Ordinance.

Additional review has been applied to mitigation measures to clarify changed names of agencies, mitigation that has already been implemented, reflection of changes in law, and clarification of ministerial implementation. This clarifying analysis and proposed mitigation measure language can be found in Section 4.18, Supplemental Analysis.

3.2 Environmental Setting

3.2.1 Regional Location

Kern County is California's third-largest county in terms of land area, encompassing 8,202 square miles. Located at the southern end of the Central Valley, Kern County serves as the gateway to southern California, the San Joaquin Valley, and California's high desert. The geography of Kern County is diverse, containing mountainous areas, agricultural lands, and desert areas.

Kern County is bounded by Kings, Tulare, and Inyo Counties on the north, San Bernardino County on the east, Los Angeles and Ventura Counties on the south, and Santa Barbara and San Luis Obispo Counties on the west. Kern County includes eight incorporated cities within the portion of the County located in the San Joaquin Valley, including Arvin, Bakersfield, Delano, Maricopa, McFarland, Shafter, Taft, and Wasco. Oil and gas exploration and development activities have historically occurred in the San Joaquin Valley Floor portion of the County and are likely to continue to occur in the same vicinity. For this reason, this SREIR evaluates potential impacts of future oil and gas exploration and production activities in a defined boundary. For the purposes of this SREIR, the area depicted in Figure 3-1 defines the Project Area. The regional location of the Project is shown on Figure 3-2.

The Kern County General Plan (KCGP) describes the San Joaquin Valley region as "the southern San Joaquin Valley below an elevation of 1,000 feet mean sea level" within Kern County. The San Joaquin Valley portion is characterized by low rainfall, averaging less than 10 inches per year. Average temperatures are relatively high, and total evaporation exceeds total precipitation. Summers are generally cloudless, hot, and dry. Winter is generally mild, but an occasional freeze does occur and may cause substantial agricultural damage. The average length of the growing season is 265 days. The San Joaquin Valley region is within the southern end of the San Joaquin Valley Air Basin managed by the SJVAPCD. This district encompasses Fresno, Kings, Madera, Merced, San Joaquin, Stanislaus, and Tulare Counties, as well as the San Joaquin Valley portion of Kern County. Further, the San Joaquin Valley region is within the Tulare Lake Groundwater Basin, which includes the Kern River Hydrographic Unit and the Poso Hydrographic Unit. These are subject to CVRWQCB oversight.

3.2.2 Project Area

The Project Area is defined as shown on Figure 3-1 and encompasses 3,700 square miles, which generally includes most of the San Joaquin Valley Floor portion of Kern County and additional areas in the southern portion of the Project Area. The boundary is defined as follows: west side – the San Luis Obispo, Monterey, and Santa Barbara county lines; north side – the Kings and Tulare county lines; east side – the 2,000-foot elevation contours, squared off to the nearest section line; and south side – the northern boundary of the Los Padres National Forest and portions of the San Emigdo and Tehachapi Mountains. The Project Area boundary is based on information regarding areas with potential or confirmed oil and gas resources within the County's jurisdiction.

Although the Project Area encompasses 3,700 square miles, the SREIR impact analysis includes only unincorporated County land. Therefore, the analysis includes unincorporated County land within the 409-square-mile Metropolitan Bakersfield Planning Area (a joint planning area containing both County and City land), but excludes all adjacent City of Bakersfield land. The SREIR analysis also excludes all other city jurisdictions, such as Taft, Delano, Shafter, Arvin, McFarland, Maricopa, and Wasco. Lands under the jurisdiction of various state and federal agencies, including the BLM, USFWS, and the California State Lands Commission, are also included within the 3,700-square-mile Project Area but are excluded from the EIR impact analysis. Ancillary equipment and land uses (e.g., pipelines and access roads on unincorporated County lands are included in the Project Area and analyzed in the SREIR, and are regulated by the County even though such equipment and land uses may serve wells on non-jurisdictional County lands (e.g., incorporated cities or federal/state lands). By conservatively assuming that all new well activities in Kern County would occur in the Project Area of the County's jurisdictional lands, this SREIR presents a conservative analysis of likely impacts in the Project Area. This SREIR also addresses non-jurisdictional areas as part of the cumulative impacts analysis.

To facilitate detailed analysis, the Project Area is divided into three Subareas, as depicted in Figure 3-1. In general, the Project Subareas are divided along the major transportation corridors.

Western Subarea

The Western Subarea consists of 1,714 square miles (1,096,840 acres) and is generally bounded by the Kern County border on the north and west, Los Padres National Forest on the south, and by Interstate 5 (I-5) on the east. The Western Subarea contains many of the large-scale oil and gas extraction-level operations. The Western Subarea contains 37 active oil and gas fields, including five of California's largest producing oilfields (by volume). The area also includes dispersed agricultural operations. The Western Subarea contains unincorporated areas around the cities of Taft and Maricopa that are located in the Western Subarea.

Central Subarea

The Central Subarea consists of 1,025 square miles (656,003 acres) and is generally bounded by the Kern County border on the north, by I-5 on the west, and State Route 65 and State Route 223 on the East. The Central Subarea contains 21 active oil and gas fields, some with large-scale production activity. The Central Subarea contains some of the County's deepest wells, with oil operations co-locating with predominant agricultural activities in this Subarea. The Central Subarea contains parts of the unincorporated Metropolitan Bakersfield area and includes unincorporated areas around the cities of Shafter, Delano, Wasco, and McFarland.

Eastern Subarea

The Eastern Subarea consists of 953 square miles (over 600,000 acres) and is generally bounded by the County border on the north, State Route 65 and State Route 223 on the west, and mountain ranges on the east and the south. The Eastern Subarea contains 20 active oil and gas fields along with several large-scale oil and gas production areas, such as the Kern River Oilfield north of the City of Bakersfield, in the Oildale area. The Eastern Subarea includes parts of the unincorporated Metropolitan Bakersfield area and unincorporated areas around the city of Arvin.

3.2.3 Land Uses Surrounding the Project Area

The Project Area is bordered on the west by San Luis Obispo County. The border between the two counties approximates the San Andreas Fault line. The Temblor Range forms a general barrier between the more industrial oil drilling operations on the Kern County side of the border versus the more rural and agricultural nature of neighboring San Luis Obispo County, with the exception of the Midway Sunset Oilfield, which crosses into neighboring San Luis Obispo County. The portion of the Midway Sunset Oilfield located within San Luis Obispo County is outside of the Project Area and is not subject to Kern County jurisdiction. Other oil and gas uses exist to the west of the Project Area; however, such activities are less intensive in nature and dispersed throughout a rural area.

Similarly, in the southwest, the Project Area extends to the border of the Los Padres National Forest, and in the southeast includes portions of the San Emigdo Mountains and the Tehachapi Mountains. The unincorporated community of Frazier Park is located in the uplands several miles south of the Project Area and west of I-5.

To the north, the Project Area is bordered by Kings and Tulare Counties. The bordering areas of these two counties contain agricultural and oil and gas operations, as well as dispersed rural residences. The incorporated City of Delano is located on the northern border of Kern County and adjacent land uses in Tulare County consist of large lot residential, agriculture, and industrial uses.

To the east, the Project Area is bordered by the foothills of surrounding mountain ranges, such as the Greenhorn Mountains and Tehachapi Mountains, as well as the Tejon Hills southeast of the incorporated City of Arvin. The Project Area also borders the Sequoia National Forest northeast of Bakersfield. Land uses along the border are generally rural in nature.

3.2.4 Areas Not Subject to Kern County Land Use Jurisdiction Located Within Project Area

As described above and in Figure 3-1, there are several incorporated cities, as well as lands and minerals owned by the federal or state government, that fall within the Project Area. Although the Project does not directly affect these areas outside the County's land use jurisdiction, the SREIR assumes that oil and gas activities that occur in these areas will continue to occur in the future, and this SREIR addresses County jurisdictional activities that occur as ancillary activities in support of oil and gas production in these areas, including, for example, electric transmission lines, pipelines, and access roads. Oil and gas activities in these areas are also considered in the cumulative impacts analysis of this SREIR. However, well count projections, which are used to assess many types of impacts in this SREIR, exclude anticipated development that would occur in these areas (i.e., incorporated cities and BLM lands) within the Project Area.

In the event that future changes to municipal boundaries result in the removal of a portion of the Project Area from Kern County's jurisdiction, municipal zoning would apply rather than the County's Amended Zoning Ordinance. As noted above, cities and other local agencies within the Project Area may use the information included in this SREIR for local planning and other activities, while federal agencies may use information included in this SREIR in their National Environmental Policy Act review. Conversely, in the event that future changes to municipal boundaries result in a transfer of current municipal lands to the County's jurisdiction, the Amended Zoning Ordinance would apply to those lands.

3.2.5 Kern County Zoning Ordinance

Section 19.98.020 of the existing Kern County Zoning Ordinance currently authorizes "unrestricted drilling," with no County permit required, in County lands zoned for Exclusive Agriculture (A), Limited Agriculture (A-1), Medium Industrial (M-2), Heavy Industrial (M-3), and Natural Resource (NR), subject to compliance with specified conditions and standards that augment CalGEM, the SJVAPCD, and applicable fire and safety ordinances and regulations of the County of Kern. In these zoning districts, no County review or permit is required for the drilling of any steam injection well, steam drive well, service well, or any well intended for the exploration for, or development or production of, oil, gas, and other hydrocarbon substances, or for any related ancillary equipment, structure, or facility used as part of the oil and gas production process. The existing ordinance further requires that drilling cannot occur within 100 feet of any existing residence without the written consent of the owner thereof.

Oil or gas exploration or production is allowed within the Floodplain Primary (FPP) District, subject to the Special Review Procedures and Development Standards in Section 19.50.130. Oil or gas exploration or production is permitted within a Special Planning (SP) District, provided it is consistent with the KCGP land use designation applicable to the subject property and does not create a conflict with public health, safety, and welfare.

Section 19.98.030 provides for drilling by "ministerial permit" in several other zoning districts. The current drilling "ministerial" permit requires an application and review process, but the County does not impose site-specific conditions on these permits and the applicant is entitled to receive the permit once it demonstrates that relevant standards are met. Ministerial permits are required in the Light Industrial (M-1) and Recreation-Forestry (RF) districts, subject to specified development standards, which also apply in Drilling Island (DI) zone districts and Petroleum Extraction (PE) combining districts. Under this current ministerial permit provision, no injection well and no well for the exploration for, or development or production of, oil or gas or other hydrocarbon substances may be drilled, and no related accessory equipment, structure, or facility may be installed in the above-referenced zone categories, until an application for a plot plan review has been submitted to and approved by the Kern County Planning Director; the application must show consistency with the development standards set out in Section 19.98.050. These development conditions and standards are presented below.

A Conditional Use Permit (CUP), which is a discretionary permit process allowing the County to establish site-specific conditions and, under appropriate circumstances, deny an application, is required for oil or gas exploration or production in all residential districts, including the Estate District (E), as well as in the Low-, Medium-, and High-Density Residential Districts (R-1, R-2, and R-3, respectively). A CUP is also required in commercial districts, including the Commercial Office District (CO), Neighborhood Commercial District (C-1), General Commercial District (C-2), and the Highway Commercial District (CH), as well as in the Platted Lands District (PL). The CUP provisions are set out in Section 19.104.

Oil or gas exploration or production is prohibited in the Mobile Home Park District (MP) (Section 19.26.040) and in the Open Space District (OS) Zoning Districts (Section 19.44.040).

Table 3-3 summarizes the type of County approvals currently required for oil or gas exploration or production activities, as well as required setback distances from designated types of nearby land uses, for each type of zone district under the existing County ordinance.

Table 3-3: Kern County Zoning Ordinance – Existing County Approval Procedure and Setback Requirements for New Oil and Gas Production

	Zone Districts	Type of County Approval Required: Unrestricted [a]	Ministerial Permit [b]	CUP	Prohibited	Set Back Required (in feet): Dwelling	Public Highway or Building	Buildings Used as Place of Assembly, Institution or School	Any Building Used for Commercial Purposes
	1. Agricultural Districts								
A	Exclusive Agriculture District	●				100	N/A	N/A	N/A
A-1	Limited Agriculture District	●				100	N/A	N/A	N/A
	2. Residential Districts								
E	Estate District			●		150	100	300	50 [c]
R-1	Low-Density Residential District			●		150	100	300	50 [c]
R-2	Medium-Density Residential District			●		150	100	300	50 [c]
R-3	High-Density Residential District			●		150	100	300	50 [c]
MP	Mobile Home Park District				●				
	3. Commercial Districts								
CO	Commercial Office District[g]			●		150	100	300	50 [c]
C-1	Neighborhood Commercial District[g]			●		150	100	300	50 [c]

Table 3-3: Kern County Zoning Ordinance – Existing County Approval Procedure and Setback Requirements for New Oil and Gas Production

		Type of County Approval Required				Set Back Required (in feet)			
	Zone Districts	Unrestricted [a]	Ministerial Permit [b]	CUP	Prohibited	Dwelling	Public Highway or Building	Buildings Used as Place of Assembly, Institution or School	Any Building Used for Commercial Purposes
C-2	General Commercial District[g]			●		150	100	300	50 [c]
CH	Highway Commercial District[g]			●		150	100	300	50 [c]
	4. Industrial Districts								
M-1	Light Industrial District		●			150	100	300	50 [c]
M-2	Medium Industrial District	●				100	N/A	N/A	N/A
M-3	Heavy Industrial District	●				100	N/A	N/A	N/A
	5. Special Purpose Districts								
RF	Recreation-Forestry District		●			150	100	300	50 [c]
OS	Open Space District				●	N/A	N/A	N/A	N/A
NR	Natural Resource District	●				100	N/A	N/A	N/A
DI	Drilling Island District (used within subdivided residential areas)					300	100	300	50 [c]
FPP	Floodplain Primary District	● [d]				(6)	(6)	(6)	(6)
SP	Special Planning District	● [e]				N/A	N/A	N/A	N/A

Table 3-3: Kern County Zoning Ordinance – Existing County Approval Procedure and Setback Requirements for New Oil and Gas Production

Zone Districts		Type of County Approval Required				Set Back Required (in feet)			
		Unrestricted [(a)]	Ministerial Permit [(b)]	CUP	Prohibited	Dwelling	Public Highway or Building	Buildings Used as Place of Assembly, Institution or School	Any Building Used for Commercial Purposes
PL	Platted Lands District [(g)]			●		150	100	300	50 [(c)]
PE	Petroleum Extraction[(g)(h)]		●			300	100	300	50 [(c)]

Notes:

(a) "Unrestricted Drilling" requires no County review or County permit, subject to compliance with specified conditions and standards that augment CalGEM, SJVAPCD, and other agency regulations.

(b) Ministerial Permit requires submittal of an Application for Plot Plan Review to Kern County Planning Director.

(c) A well is not permitted within 50 feet of any building used for commercial purposes without written consent of structure owner prior to the commencement of such drilling

(d) Subject to Special Review Procedures and Development Standards in Section 19.50.130, including Flood Damage Prevention Ordinance, Chapter 17.48 of the Code.

(e) Allowed if use is consistent with General Plan Land Use designation and will not conflict with public health, safety, or welfare.

(f) No minimum setback required. Building and structures are not allowed.

(g) Zone districts that require a CUP for new oil and gas production wells Per Section 19.98.050 and 19.98.040, allows for standards such as setbacks to be reduced or waived as part of the CUP approval process if it is determined that it would not be detrimental to public welfare and/or adjacent property owners.

(h) Per Section 19.66.020(A), new wells are to be more than 300 feet from an existing dwelling. Section 19.66.030(A) specifies that wells located closer than 300 feet to an existing residence or buildings used for commercial purposes can be authorized through the issuance of a CUP.

Key:

CalGEM = California Geologic Energy Management Division

CUP = Conditional Use Permit

N/A = Not Applicable

SJVAPCD = San Joaquin Valley Air Pollution Control District

Existing Development Standards and Conditions

Chapter 19.98 (Oil and Gas Production) of the Kern County Zoning Ordinance currently contains the procedures and standards that apply to the exploration for development or production of oil, gas, and other hydrocarbon substances and related facilities carried out in unincorporated Kern County pursuant to Section 19.48.020, 19.98.030, and 19.98.040 of the Zoning Ordinance. Existing development standards and conditions included in Chapter 19.98 were designed to address various environmental and public health and welfare concerns, and are summarized below. These existing standards and conditions would be modified and/or supplemented by the Amended Zoning Ordinance:

- **Specific well setback distances from public highways and buildings** (19.98050.A) – No oil or gas well shall be drilled within one hundred (100) feet of any public highway or building not necessary to the operation of the well, or within one hundred and fifty (150) feet of any dwelling, or within three hundred (300) feet of any building used as a place of public assembly, institution, or school, or within fifty (50) feet of any building utilized for commercial purposes constructed prior to the commencement of such drilling, without the written consent of the owner of such structure. The required setbacks in various zone districts are presented on Table 3-3.
- **Fire and safety regulations** (19.98.050.B) – All drilling and production activities shall conform to all applicable fire and safety regulations, and firefighting apparatus and supplies required by the Kern County Fire Department shall be maintained on the site at all times during drilling and production operations.
- **Limitations on project signage** (19.98.050.C) – No signs, other than directional and warning signs and those required for identification of the well, shall be constructed, erected, maintained, or placed on the premises or any part thereof, except those required by law or ordinance to be displayed in connection with the drilling or maintenance of the well.
- **Sanitary toilet and washing facilities** (19.98.050.D) – Sanitary toilet and washing facilities, if required by the Kern County Health Department or other governmental agencies, shall be installed and maintained in a clean and sanitary condition during drilling operations, and at such other times as specified by these agencies.
- **Proven technological improvements** (19.98.050.E) – Proven technological improvements generally accepted and used in drilling and production methods shall be employed as they may become available if they are capable of reducing nuisances or annoyances.
- **Timely removal of drilling equipment** (19.98.050.F) – All derricks, boilers, and other drilling equipment used to drill, repair, clean out, deepen, or redrill any completed or drilling well must be removed within 90 days after completion of production tests or after abandonment of any well, unless such derricks, boilers, and drilling equipment are to be used within a reasonable time for the drilling of another well or on the premises.

- **Filling of earthen sumps and restoration of drilling sites** (19.98.050.G) – Within ninety (90) days after any well has been placed in production, or after its abandonment, earthen sumps used in drilling or production or both (unless such sumps are to be used within a reasonable time as determined by the Planning Director for the drilling of another well or wells) shall be filled and the drilling site restored as nearly as practicable to a uniform grade. Temporary earthen sumps may be used for cleanout or remedial work on an existing well or other production facility. However, these sumps shall be filled and the site restored as nearly as practicable to uniform grade within ninety (90) days after the cleanout or other remedial work is completed. Such restoration work shall comply with all applicable regulations of the California Division of Oil and Gas.
- **Portable derricks** (19.98050.H) – Any derrick used for servicing operations shall be of the portable type, provided, however, that upon presentation of proof that the well is of such depth or has such other characteristics, or for other cause, that a portable type derrick will not properly service such well, the Planning Director may approve the use of a standard type of derrick.
- **Tank setbacks, landscaping and fencing** (19.98.050.I) – Whenever oil or gas is produced into and shipped from tanks located on the premises, such tanks, whenever located within five hundred (500) feet of any dwelling or commercial building, shall be surrounded by shrubs or trees, planted and maintained so as to develop attractive landscaping or shall be fenced in such a manner as to, insofar as practicable, screen such tanks from public view. Such fencing shall comply with the requirements of the California Division of Oil and Gas (promulgated in California Code of Regulations [CCR], Title 14, Division 2, Chapter 4, Subchapter 2, Section 1778).
- **Material delivery restrictions** (19.98.050.J) – Whenever a well is located within five hundred (500) feet from an existing dwelling unit, except in case of an emergency, no materials, equipment, tools, or pipe used for either drilling or production operations shall be delivered to or removed from the drilling site, except between the hours of eight (8:00) a.m. and eight (8:00) p.m., unless otherwise required by the California Division of Oil and Gas.
- **Electric motors/muffled engines** (19.98.050.K) – Pumping wells shall be operated by electric motors or muffled internal combustion engines.
- **Height restrictions and paint requirements for pumping units** (19.98.050.L) – The height of all pumping units shall not exceed thirty five (35) feet and shall be painted and kept in neat order.
- **Dust abatement requirements for parking areas** (19.98.050.M) – All vehicle parking and maneuvering areas must be treated and maintained with oiled sand or a similar dust binding material.
- **Landscaping and fencing requirements for oil tanks** (19.98.050.N) – After production begins and a pump is installed on the wellhead, a fence at least six (6) feet in height shall be installed around the pump site or drilling island for public safety. This fence shall be constructed of chain link with wood or metal slats or other screening fence as may be

approved by the Planning Director. This fencing and screening requirement shall apply only to those pump sites located within five hundred (500) feet of any dwelling. Such fencing shall comply with the requirements of the California Division of Oil and Gas.

- **Compliance with federal, state, and County rules** (19.98.050.O) – All required federal, state, and County rules and regulations shall be complied with at all times, including, but not limited to, the rules and regulations of the following agencies:
  1. California Division of Oil and Gas
  2. Kern County Fire Department
  3. Kern County Health Department
  4. Regional Water Quality Control Board
  5. Air Pollution Control District
  6. Kern County Engineering and Survey Services Department
- **Dark skies ordinance** (19.51) – The existing dark skies ordinance does not apply to oil and gas activities.

3.3 History, Existing Operations, and Background

Oil drilling in Kern County has a long history. The first commercially developed oilfield in Kern County was the McKittrick Field, which was developed in 1898. Development was facilitated by existence of the Southern Pacific Railroad from Bakersfield to McKittrick. The Kern River Field, north of Bakersfield, was established in 1899 with the discovery of oil at that time. By 1903, 796 wells produced almost 17 million barrels of oil from the Kern River Field.

In the mid-1930s, several valley oilfields were found in large anticlines in Miocene oil sands beneath the valley floor. These discoveries were made following the advent of the reflection seismograph. Discoveries included Ten Section, Greeley, Rio Bravo, North Coles Levee, South Coles Levee, and Strand.

Kern County is the largest oil producing county in the state. According to the CalGEM, in 2012, Kern County, with nearly 43,000 active oil and gas, dry gas, and gas storage wells, contained 78% of all active wells in California (DOGGR 2013a). In addition, 80% of all oil and natural gas produced in California came from wells in Kern County.

Kern County is located within District #4 of CalGEM. All resources produced in the district listed in state publications are from Kern County, except for about 1% that come from Tulare, Kings, and San Luis Obispo Counties. Table 3-4 presents a summary of oil and gas production statistics for Kern County, from 2002 to 2013.

Table 3-4: Kern County/Oil and Gas Production Statistics (2002 through 2013)

Year	Well Count		Oil Production (bbl)	Total Gas Production (Mcf)	Produced Water (bbl)
	Active	Inactive			
2013 [a] [b]	43,568	15,863	141,642,659	137,775,170	1,794,103,912
2012 [c] [d]	42,875	15,803	141,693,959	143,161,183	1,847,748,513
2011 [e]	NA	NA	143,286,239	150,138,919	1,729,110,447
2010 [f]	NA	NA	148,149,302	159,891,426	1,623,436,443
2009 [g]	42,067	14,344	154,862,689	143,803,250	1,571,530,199
2008 [h]	42,347	13,968	162,286,447	154,497,502	1,452,401,425
2007 [i]	40,820	14,667	166,169,131	164,996,739	1,360,061,057
2006 [i]	40,066	15,113	170,164,866	178,641,271	1,307,556,746
2005 [j]	38,762	15,849	176,700,868	179,705,645	1,308,930,959
2004 [k]	38,144	15,556	185,222,203	184,787,625	1,257,553,976
2003 [k]	37,480	15,662	191,634,994	193,094,181	1,194,529,857
2002 [l]	37,178	16,405	198,839,444	209,485,454	1,159,205,228

Sources:
[a] DOGGR 2014a
[b] DOGGR 2014b
[c] DOGGR 2013a
[d] DOGGR 2013b
[e] DOGGR 2012
[f] DOGGR 2011
[g] DOGGR 2010
[h] DOGGR 2009
[i] DOGGR 2008
[j] DOGGR 2006
[k] DOGGR 2005
[l] DOGGR 2003

Key:
bbl = barrels
MCF = 1,000 cubic feet of gas
NA = data not available

Surface and Mineral Rights

Petroleum exploration and extraction involves the use of surface land for the establishment of well drilling and associated activities. The “surface rights”—that is, the right to use the surface of the land—are distinct from the “mineral rights,” which pertain to minerals beneath the surface. The rights to use the land surface for these activities are governed by applicable laws, regulations, court orders, and agreements that oil and gas operators have established with various landowners. In some cases, the surface rights and the mineral rights to the same area of land may be owned by two different parties. This is referred to as a “split estate.”

Although the reservoir that contains the oil and gas may be under land that has businesses, parks, and residences on them, the minerals can be extracted because an oil or gas operator owns the “mineral rights” to the minerals beneath the land surface. A mineral right is an interest in real property and may be sold, transferred, leased, or retained separately from the surface rights, in which case the mineral rights are said to be “severed.” Mineral rights are distinct from “surface rights," or the right to the use of the surface of the land for residential, agricultural, recreational, commercial, or other purposes.

A person may own all of the mineral rights for a parcel or any fraction of the rights. A person may also own rights to only one kind of mineral, such as oil and gas, or to only one formation or depth interval. The ownership of the producing mineral rights in a parcel can usually be determined by examining the deed abstract for the property. The rights of the mineral owner to use of the surface of the real property are dominant to the rights of the owner of the surface estate, meaning that the mineral owner has an appurtenant right to reasonable access to develop its mineral right. The rights of a mineral owner to use of the surface estate can only be restricted by an express grant of such rights from the mineral owner to the surface owner. Mineral rights are, in all respects, real property rights. Real property rights are those rights primarily established under the common law of California and generally governed by the California Civil Code, Division 2, Part 2.

3.3.1 Administrative Oilfields

A total of 100 active or abandoned "Administrative Oilfields" (AOFs), which are delineated by CalGEM under applicable state regulations, are located on County jurisdictional lands within the Project Area. As shown in Table 3-5, these CalGEM delineated AOFs vary widely in size, from the smallest being the Kernsumner and Temblor East wellfields at 0.2 square mile, to the largest being Midway Sunset Oilfield at 99.7 square miles. The boundaries of these AOFs are referred to as "Administrative Boundaries." Oil and gas production also occurs outside of CalGEM delineated oilfield Administrative Boundaries. Table 3-5 notes whether each oilfield is within the Western, Central, or Eastern Subarea, as proposed by the Project and as shown on Figure 3-3, and whether the field is active or has been abandoned. The locations of AOFs within the Project Area are shown on Figure 3-3.

Table 3-5: Oilfields Currently Delineated by the California Geologic Energy Management Division within the Project Area

Count	Administrative Oilfield [Alpha Order]	Square Miles [(a)]	Acres [(a)]	Subarea
1	Ant Hill	1.7	1,098.0	E
2	Antelope Hills	4.4	2,823.7	W
3	Antelope Plains Gas (Abd)	0.3	160.5	W
4	Asphalto	4.6	2,975.5	W
5	Beer Nose	1.0	644.8	W
6	Belgian Anticline	15.4	9,864.9	W
7	Bellevue	3.6	2,326.4	C
8	Blackwells Corner	3.6	2,308.1	W

Table 3-5: Oilfields Currently Delineated by the California Geologic Energy Management Division within the Project Area

Count	Administrative Oilfield [Alpha Order]	Square Miles [(a)]	Acres [(a)]	Subarea
9	Bowerbank	16.2	10,352.4	C
10	Buena Vista	46.9	29,993.3	W
11	Buttonwillow Gas (Abd)	10.0	6,378.7	C
12	Cal Canal Gas	5.5	3,515.2	W
13	Calders Corner	1.5	970.0	C
14	Canal	3.9	2,476.7	C
15	Canfield Ranch	13.3	8,536.4	C
16	Capitola Park	1.0	651.5	W
17	Carneros Creek	1.5	967.3	W
18	Chico Martinez	2.6	1,634.8	W
19	Cienaga Canyon	0.6	402.4	W
20	Comanche Point	1.9	1,202.7	E
21	Cymric	21.5	13,757.8	W
22	Devils Den	12.8	8,175.4	W
23	Dyer Creek	0.4	239.9	E
24	Eagle Rest	0.5	309.3	W
25	Temblor, East (Abd)	0.2	154.6	W
26	Edison	34.0	21,742.3	E
27	Elk Hills	72.9	46,630.7	W
28	English Colony	1.1	681.5	C
29	Fruitvale	18.3	11,714.2	E
30	Garrison City Gas (Abd)	4.7	3,017.4	C
31	Gonyer Anticline (Abd)	0.5	344.9	W
32	Goosloo	3.0	1,935.4	C
33	Greeley	9.4	6,022.4	C
34	Jasmin	10.3	6,607.4	E
35	Jerry Slough (Abd)	0.5	318.0	C
36	Kern River	25.8	16,532.6	E
37	Kern Bluff	4.2	2,668.6	E
38	Kern Front	19.0	12,136.1	E
39	Kernsumner (Abd)	0.2	159.7	E

Table 3-5: Oilfields Currently Delineated by the California Geologic Energy Management Division within the Project Area

Count	Administrative Oilfield [Alpha Order]	Square Miles [(a)]	Acres [(a)]	Subarea
40	Lakeside	1.3	804.0	C
41	Landslide	2.1	1,373.9	W
42	Los Lobos	6.1	3,892.3	W
43	Lost Hills	33.2	21,273.1	W
44	McClung (Abd)	0.5	319.6	C
45	McDonald Anticline	3.7	2,372.4	W
46	McKittrick	10.6	6,776.8	W
47	Midway – Sunset[(2)]	99.7	63,832.8	W
48	Monument Junction	3.3	2,085.6	W
49	Mountain View	28.5	18,251.2	E
50	Mount Poso	45.9	29,360.5	E
51	Antelope Hills, North	3.9	2,466.8	W
52	Belridge, North	9.1	5,800.9	W
53	Coles Levee, North	15.1	9,671.0	W
54	Shafter, North	7.5	4,768.3	C
55	Tejon, North	9.2	5,914.3	C
56	Edison, Northeast	0.6	408.8	E
57	Lost Hills, Northwest	8.6	5,507.7	W
58	Semitropic Gas, Northwest (Abd)	0.5	322.5	C
59	Paloma	29.7	18,985.0	W
60	Pioneer	1.0	642.8	W
61	Pleito	3.0	1,927.3	W
62	Poso Creek	30.9	19,806.9	E
63	Railroad Gap	1.7	1,101.2	W
64	Rio Bravo	6.1	3,925.0	C
65	Rio Viejo	4.1	2,641.7	W
66	Rose	5.5	3,522.1	C
67	Rosedale	3.6	2,321.0	C
68	Rosedale Ranch	5.0	3,213.3	C
69	Round Mountain	19.2	12,265.9	E

Table 3-5: Oilfields Currently Delineated by the California Geologic Energy Management Division within the Project Area

Count	Administrative Oilfield [Alpha Order]	Square Miles [(a)]	Acres [(a)]	Subarea
70	Round Mountain South	0.4	276.7	E
71	San Emidio Nose	7.6	4,880.5	W
72	San Emigdio (Abd)	0.5	306.1	W
73	San Emigdio Creek (Abd)	0.5	340.7	W
74	Semitropic	25.1	16,077.3	C
75	Seventh Standard	0.5	320.3	C
76	Shafter (Abd)	0.5	321.2	C
77	Shafter Southeast Gas (Abd)	1.0	641.5	C
78	Shale Flats Gas (Abd)	1.0	647.1	W
79	Shale Point Gas	0.6	387.2	W
80	Belridge, South	25.3	16,218.0	W
81	Coles Levee, South	17.7	11,328.4	W
82	Lakeside, South (Abd)	0.3	160.4	C
83	Stockdale	2.4	1,567.5	E
84	Strand	7.9	5,068.5	C
85	Tejon	11.3	7,227.8	E
86	Tejon Flats (Abd)	0.3	161.0	E
87	Tejon Hills	6.7	4,283.2	E
88	Temblor Hills	1.0	643.9	W
89	Temblor Ranch	0.5	318.4	W
90	Ten Section	7.4	4,725.9	C
91	Trico Gas [(b)]	6.8	4,359.4	C
92	Union Ave.	1.0	655.3	E
93	Valpredo	0.3	163.1	E
94	Wasco	4.0	2,575.6	C
95	Welcome Valley	0.8	490.4	W
96	Bellevue, West	2.0	1,248.3	C
97	Jasmin, West (Abd)	0.5	321.6	E
98	Wheeler Ridge	8.1	5,203.7	W

Table 3-5: Oilfields Currently Delineated by the California Geologic Energy Management Division within the Project Area

Count	Administrative Oilfield [Alpha Order]	Square Miles [(a)]	Acres [(a)]	Subarea
99	White Wolf	1.3	846.3	W
100	Yowlumne	10.1	6,446.8	W
	TOTAL	**931.4**	**596,198.3**	**--**

Source: DOGGR 2013c.
Notes:
(a) Numbers are approximate.
(b) Oilfield is located on the border of Kern County and an adjacent county; acreages within Kern County are approximate.
Key:
Abd = Abandoned
C = Central Subarea
E = Eastern Subarea
W = Western Subarea

3.4 Project Description

3.4.1 Proposed Project/Proposed Zoning Code Amendment

The proposed Project consists of an amendment to Title 19 of the Kern County Zoning Ordinance, Chapter 19.98 (Oil and Gas Production), and related sections of the Kern County Zoning Ordinance to include updated procedures, development and implementation standards, and conditions for future oil and gas exploration, development, and production activities in unincorporated Kern County. In addition, the proposed Project includes the implementation of future oil and gas development activities expected to be undertaken pursuant to the amended ordinances.

The proposed Project would amend sections of the Kern County Zoning Ordinance relating to oil and gas drilling, including but not limited to Chapter 19.98 (Oil and Gas Production), to address oil and gas exploration and operation activities in greater detail, by:

a) Establishing updated development and implementation standards and conditions to address environmental impacts of pre-drilling exploration, well drilling, and the operation of wells and other oil and gas production-related equipment and facilities, including exploration, production, completion, stimulation, reworking, injection, monitoring, and plugging and abandonment; and

b) Establishing new "Oil and Gas Conformity Review" and "Minor Activity Review" ministerial permit procedures for County approval of future well drilling and operations to ensure compliance with the updated development and implementation standards and conditions and provide for ongoing tracking and compliance monitoring.

The Amended Zoning Ordinance incorporates a comprehensive update to all sections of the Zoning Ordinance related to oil and gas exploration and production. The following description outlines the proposed changes to the Zoning Ordinance. (Note: A complete copy of the amendments to the Zoning Ordinance is provided at the end of this chapter as Attachment A.)

a) A comprehensive overhaul of Chapter 19.98 would be made to remove the "Unrestricted Drilling" section and to update the "Drilling by Ministerial Permit" and "Drilling by Conditional Use Permit" sections. This update would require all new oil and gas wells for exploration or production to obtain approval from the Kern County Planning and Natural Resources Department prior to commencing drilling.

b) The Tier System, described fully in Section 3.4.4, below, would be incorporated into Chapter 19.98 to address the different land uses and zone districts where oil and gas activities occur. The Tier system is made up of 5 distinct Tiers: Tier 1 Areas, primarily existing oil and gas activities; Tier 2 Areas, primarily existing agricultural activities; Tier 3 Areas, primarily existing industrial development; Tier 4 Areas, primarily existing urban development (CUP Required); and Tier 5 Areas, consisting of existing and future adopted Specific Plans. The Tier Areas within the Project Area are depicted on Figure 3-4.

c) An Oil and Gas Conformity Review would be required as part of the "Drilling by Ministerial Permit" Section, noted above. This review will allow for comprehensive review of all drilling activities and will require consistent, comprehensive mitigation based on defined Tiers of surrounding land uses, as specified in the Amended Zoning Ordinance. An application package must be submitted that includes a site plan and written documentation assuring compliance with all applicable Development and Implementation Standards and Conditions.

d) A Minor Activity Review would be required as part of the "Drilling by Ministerial Permit" Section, noted above. This review will allow for comprehensive review of minor oil and gas activities and will require consistent, comprehensive mitigation based on defined Tiers of surrounding land uses, as specified in the Amended Zoning Ordinance. An application package must be submitted with written documentation assuring compliance with all applicable Development and Implementation Standards and Conditions.

e) The Development and Implementation Standards and Conditions Section would be updated to require compliance with all applicable mitigation measures and additional regulatory requirements as set forth in this SREIR. Some of these new standards include: setbacks from sensitive receptors, reductions in overall footprint of drilling areas, new screening requirements, and measures to avoid or reduce impacts to resources such as biological and cultural areas, groundwater, and air quality, as specified in the Amended Zoning Ordinance.

f) For all Oil and Gas Conformity Review Site Plans submitted to the County, the Applicant would be required to submit a signature block and statement as part of the Application package. The signature block will provide for the signatures of the Applicant and, if different, the Mineral Owner. In addition, for activities occurring on split estate lands, where the Land/Surface Owner is different from the Mineral Owner, the signature block will provide for the signature of the Land/Surface Owner. For applications submitted with the required signature block and statement, the first review by the County will take place within seven business days. If the County finds the application to be incomplete and requests additional information, the second review will take place within three business days upon receipt of the requested information.

g) The new ordinance also includes a separate application processing procedure for applications on split estate lands that are lacking a signature block signed by the Land/Surface Owner. For applications submitted without the required signature block and statement, the review process will take 30 days to allow time for surface owner consultation, with an automatic 30-day second review period. Should the Applicant obtain the Land/Surface Owner's signature during either 30-day review period, the application will be processed within seven days. However, an application will not be rejected for lack of a signature by the Land/Surface Owner.

h) A new fee structure would be included to ensure that all mitigation is complied with and that the County will be sufficiently staffed to review all new applications.

i) Other Sections of the Zoning Ordinance would be updated to ensure consistency with the new requirements of this SREIR. These Sections include: 19.08 – Interpretations and General Standards, 19.48 – Drilling Island (DI) District, 19.50 – Floodplain Primary District, 19.66 – Petroleum Extraction (PE) Combining District, 19.81 - Outdoor Lighting (Dark Skies Ordinance), 19.88 – Hillside Development, 19.102 – Permit Procedures, and 19.108 – Nonconforming Uses, Structures, and Lots.

Section 3.4.5 provides a more detailed description of the Oil and Gas Conformity Review Process.

3.4.2 Geographic Scope

For purposes of this SREIR, the Project Area is defined as shown on Figure 3-1. The updated development standards and conditions would apply to all oil and gas activities throughout unincorporated Kern County, including, but not limited to, those that fall within the Project Area. However, the proposed geographic scope of the environmental evaluation considered in this SREIR is limited to the Project Area, which represents the portion of the County in which oil and gas development has historically occurred and is reasonably foreseeable to occur in the coming decades. In the unlikely event that oil and gas production activities are proposed outside the Project Area, supplemental environmental review under CEQA would be required.

3.4.3 Core Areas

CalGEM requires oil and gas production wells to be reported, and each is ultimately included in an "Administrative Boundary" area for CalGEM's regulatory oversight purposes. However, oil and gas exploration and production does take place outside of existing Administrative Boundaries. If a new well is drilled outside the Administrative Boundary, the boundary may be adjusted by CalGEM upon written request of the operator once the new well reaches a sustained and documented production output for a minimum of six months.

For purposes of this SREIR, CalGEM's existing Administrative Boundaries were useful in predicting where the vast majority of future oil and gas production activity would occur (i.e., in and adjacent to areas within Administrative Boundaries). This SREIR uses the term "Core Area" to describe locations within and immediately adjacent to CalGEM's Administrative Boundary areas. Figure 3-5 depicts Core Areas in relation to CalGEM's Administrative Boundaries.

The County's zoning and land use planning procedures are designed to remain stable for orderly administration over time; therefore, the CalGEM Administrative Boundary adjustment process did not provide a useful framework for zoning purposes. For purposes of administering zoning requirements within and adjacent to CalGEM's Administrative Boundaries, Core Areas were defined by making the following adjustments, as applicable, to each CalGEM Administrative Boundary, to administratively manage County zoning requirements in oil and gas production areas:

1. Each area within CalGEM Administrative Boundaries was first defined as a "Core Area" for oil and gas production purposes;
2. Adjacent areas within CalGEM Administrative Boundaries were combined into a single Core Area;
3. Consistent with County zoning practice, the irregular boundaries of each Core Area were then "squared off" and defined by the nearest Section and quarter Section lines;
4. To accommodate the probability of continued expansion at the edges of these known producing areas, the Core Area was then extended at least one-half Section from the CalGEM Administrative Boundary;
5. To accommodate known oil production activities that were adjacent to but not yet within a CalGEM Administrative Boundary, the Core Area was expanded to include adjacent sections that either contained at least two wells in the section, or contained two wells within a 640-acre area of the section; and
6. Where the Core Area mapping process described above left isolated islands or narrow strips of lands between Core Areas, the Core Area was combined to eliminate these orphaned areas.

Historically, more than 95% of oil and gas production occurs within CalGEM's Administrative Boundaries. This SREIR anticipates that this same percentage of production would occur in the designated "Core Areas."

3.4.4 Tiers

Oil and gas production in Kern County varies in intensity, depending on historic uses, surrounding land uses and zoning designation, and quality of other potential land uses (e.g., agricultural land). As part of this project-level EIR process, both Core and non-Core areas within the overall Project Area were further categorized based on existing and zoned land uses. The Project Area was divided into five Tier Areas (Figure 3-4), a description of which is provided below:

Tier 1

Tier 1 is defined as the area in which current oil and gas activity is the primary land use. The well and activity densities preclude almost all other uses. According to CalGEM well information, 87% of all active oil and gas wells within the Project Area in 2014 were located within Tier 1 Areas.

The Tier 1 areas were developed through the use of well location database and oilfield Administrative Boundary geographic information system (GIS) shape files for District 4 obtained from CalGEM. Tier 1 areas generally include all quarter-quarter Sections (40 acres) that contained a minimum of four wells.

Tier 1 does not include sensitive land uses, such as schools, daycare centers, hospitals, cemeteries, etc. It should also be noted that the quarter-quarter Sections that contained Important Farmlands, as identified by the Department of Conservation's (DOC's) Farmland Mapping and Monitoring Program for Kern County, are included in Tier 2, rather than Tier 1, as described below.

Tier 2

Tier 2 includes all lands within the following agricultural zone districts that are not within Tier 1:

- All land that is zoned Exclusive Agriculture (A); and
- All land that is zoned Limited Agriculture (A-1).

Tier 2 also includes the following Important Farmlands identified by the DOC Farmland Mapping and Monitoring Program for Kern County 2012:

- Prime Farmland;
- Farmland of Statewide Importance;
- Unique Farmland; and
- Confined Animal Agriculture.

Tier 3

Tier 3 is defined as zone districts where historic drilling activity has been or could have been approved as “Unrestricted” or “Ministerial” under the existing Zoning Ordinance, and those areas that are not categorized as Tiers 1 or 2. These zone districts include:

- Natural Resource (NR);
- Recreation Forestry (RF);
- Light Industrial (M-1);
- Medium Industrial (M-2);
- Heavy Industrial (M-3);
- Floodplain Primary (FPP);
- Drilling Island (DI); and
- Zone districts that have a Petroleum Extraction (PE) combining district.

Tier 4

Tier 4 consists of all zone districts where oil or gas exploration and production activities are currently or proposed to be allowed with a CUP. These zone districts include:

- Estate District (E);
- Low-density Residential (R-1);
- Medium-density Residential (R-2);
- High-density Residential (R-3);
- Commercial Office (CO);
- Neighborhood Commercial (C-1);
- General Commercial (C-2);
- Highway Commercial (CH);
- Platted Lands (PL); and
- Mobile Home Park (MP).

Authorized oil and gas activities in Tier 4 are subject to approval of a CUP in accordance with 19.104 of this Title. The Open Space (OS) zone district includes those areas where oil or gas exploration and production activities are prohibited, but ancillary facilities are an allowable use.

Tier 5

Tier 5 are areas, including current and future Specific Plan boundaries either adopted with a Special Plan Zone District or which include specific provisions for oil and gas operations. Oil or gas exploration and production activities would be allowed with a CUP or as permitted by the regulations contained within the adopted Specific Plan(s) in Tier 5 areas.

Non-Jurisdictional Areas

Non-Jurisdictional Areas are areas where Kern County currently does not have land use authority or zone districts where oil or gas exploration and production are prohibited. These areas include lands under the administration of the Federal Government, State of California, and incorporated cities.

The land area within each Tier (in acres) is shown on Table 3-6.

Table 3-6: Summary of Tier Acreages

Tier	**Acreage [(a)]**	
Tier 1		206,747
Tier 2		1,791,303
Tier 3		16,203
Tier 4		34,450
Tier 5		2,512
Non Jurisdictional Land		283,828
Federal	117,138	
State	25,548	
Incorporated Cities [(b)]	141,142	
Other [(c)]		27,691
TOTAL [(d)]		2,362,734

Source: Prepared by Ecology and Environment, January 28, 2015.
Notes:
(a) Rounded to nearest 10th of an acre.
(b) Arvin, Bakersfield, Delano, Maricopa, McFarland, Ridgecrest, Shafter, Taft, Tehachapi, and Wasco.
(c) Includes schools, cemeteries, hospitals, and road/freeway rights-of-way.
(d) Total area based on GIS acreage of 3,692 mi^2 rounded up to 3,700 mi^2 for Project Area.
Key:
GIS = geographic information system
mi^2 = square miles

The new five-Tier zoning structure allows for project-level analysis and mitigation for oil and gas impacts in relation to differing existing and planned land uses.

3.4.5 Oil and Gas Conformity Review and Minor Activity Review Process

Oil and Gas Conformity Review

The following Oil and Gas Conformity Review process would become a mandatory process for all new oil and gas production activities occurring within Kern County (Figure 3-6). The general process is described below.

a) The Applicant would submit an Oil and Gas Conformity Review application and site plan to the County with evidence of surface/land owner notification. Concurrently, if needed, the Applicant would submit a Notice of Intention (NOI) to CalGEM, together with a copy of the Notice of Determination for this SREIR as documentation of CEQA compliance.

b) County Staff would review the Oil and Gas Conformity Application. At the conclusion of a seven business days, the County would either:

   1) Transmit a copy of the permit issuance to the Applicant, CalGEM, the Mineral Owner, and the Surface/Land Owner, or

   2) Issue a memo indicating outstanding items that require additional documentation to the applicant.

The issuance and approval of the Kern County Oil and Gas Conformity Review occurs after payment of all required mitigation fees. This permit would be active for up to one year until a permit from CalGEM is issued and any ground disturbance activities and construction activate the permit. The Applicant may request a one-year extension through the Planning Director. If an Applicant wishes to change the approved site plan in the future, they must provide a description of the new oil and gas activities or facilities and submit a new site plan with the proposed change(s), including updated signatures from all requires parties.

Before any drilling or construction activities can occur on the site the Applicant must obtain a CalGEM permit as a priority permit and then any other State or federal permits required. The Applicant must self-certify their project's compliance with the Zoning Ordinance and applicable mitigation measures during the construction and operation process and provide a final statement of completion when the well is operating. The County would provide a County Well Identification number, and the Applicant would be required to place a sticker/sign on the wellhead to identify the well. Once the Applicant has completed construction of the oil and gas facilities, as indicated on the approved site plan, they would provide a self-certified statement to the County. Then, the County would "finalize" the Oil and Gas Conformity Review in the Planning and Community Development Department's records.

For incomplete applications, the Applicant receives an outstanding items memo, and they must submit evidence documenting compliance with the items addressed in the memo. County Staff would review the submitted information and provide a response to the Applicant within three business days of the documentation submittal. The County will conduct up to three reviews. After the third submittal, if outstanding items are still not submitted, the County will require an in-person meeting with the Applicant and any consultant processing the application to resolve the issues preventing issuance of the permit. The in-person meeting cannot be waived. The County may request additional fees to supplement the County review process, which will be shown in the Ordinance for any reviews past three total (initial application submittal and two reviews).

Surface/Land Owner Sign-Off Process

Surface/land owners who are not mineral owners must receive notification of the intention to drill at least 30 days prior to submittal to County of an Oil and Gas Conformity Review application, unless they have waived the need for written notification. The written notification must include the County's handout explaining the process and full contact information for the surface/land owner (name, address for contact, phone number and email (if known). The surface/land owner can choose to sign off or not. If they do sign off, the conformity process described above would occur. If the surface owner chooses not to sign off, then the following process would occur.

a) The Kern County Planning and Natural Resources Department would conduct a review of the submitted application.

b) The County would contact the surface/land owner and offer an in-person meeting to review the County process, development, and implementation standards and the Mitigation Monitoring and Reporting Program (MMRP) and answer any questions. The Applicant would not be present, and no facilitation of the negotiations would be offered or provided only information on the standards and the process.

c) One of the following responses would be provided to the Applicant 30 business days after application submittal:

    1) The County would provide zoning issuance of the Oil and Gas Conformity Review for the proposed Oil and Gas land use activity(s) after all mitigation fees are paid.

    2) The County would provide a memo to the Applicant indicating outstanding items that require documentation prior to zoning issuance, then the process described in item (b) of the previous section would be followed; or

    3) Should the Applicant receive surface/land owner sign off and provide the County with a site plan that includes the surface owner's signature(s), then the process described in item (b) in the Oil and Gas Conformity Review section would be followed.

Minor Activity Review

The following Minor Activity Review process would become a mandatory process for all minor activities occurring within Kern County (Figure 3-6). The general process is described below.

a) The Applicant would submit a Minor Activity Review application to the County with evidence of surface owner notification.

b) County Staff would review the application. At the conclusion of a seven business days, the County would either:

   1) Transmit a copy of the Minor Activity Review Issuance to the Applicant, mineral owner, and surface/land owner, or

   2) Issue a memo indicating outstanding items that require additional documentation to the Applicant.

If an Applicant receives issuance, they must still obtain any other necessary State or federal permits, prior to commencing construction of the facility. The Applicant must self-certify their project's compliance with the Zoning Ordinance and applicable mitigation measures during the construction and operation process. Once the Applicant has completed construction of the oil and gas facilities, they would provide a self-certified statement to the County. Then, the County would "finalize" the Oil and Gas Conformity Review in the Planning and Community Development Department's records. This permit would be active for up to one year. The Applicant may request a one-year extension through the Planning Director. If the Applicant wishes to change the approved permit in the future, they must provide a description of the new oil and gas activities or facilities and must submit a new site plan with the proposed change(s), including updated signatures from all requires parties.

If an Applicant receives an outstanding items memo, they must submit evidence documenting compliance with the items addressed in the memo. County Staff will review the submitted information and provide a response to the project applicant within three business days of the documentation submittal. The County will conduct up to three reviews. After the third submittal, if outstanding items are still not submitted, the County will require an in-person meeting with the Applicant, and any consultant processing the application to resolve the issues preventing issuance of the permit. The in-person meeting cannot be waived. The County may request additional fees to supplement the County review process, which will be shown in the Ordinance for any reviews past three total (initial application submittal and two reviews).

3.5 Potential Future Oil and Gas Development Scenario

This section provides a description of the potential future drilling and operational activities that could occur within the Project Area. For analytical purposes, as described in Chapter 2, Introduction, this SREIR assumes that 2,697 new producing wells per year—a relatively high level of new oil and gas production activity—would be projected to occur each year for the next 20 years. In practice, annual activity levels would likely be lower. There is no scheduled expiration date for a Zoning Ordinance, and the development standards and conditions specified in the Amended Zoning Ordinance would continue to apply unless and until the Zoning Ordinance is amended again. Further environmental review would not likely be needed for annual oil and gas activities that qualify for ministerial permits under the Conformity Review Process, so long as the annual projected activity level is not exceeded (e.g., no more than 2,697 new producing wells are drilled in a single calendar year) and the total projected activity level assumed to occur over the next 25 years is not exceeded (e.g., no more than 67,425 wells are drilled). However, at the point that either the annual project activity level or total projected activity level is exceeded, the County will need to consider whether the exceedance triggers further CEQA review in accordance with the criteria provided in CEQA (Public Resources Code) Section 21166 and CEQA Guidelines Section 15162 (e.g., due to new or substantially more severe significant environmental impacts than those considered in this SREIR). If the criteria for subsequent or supplemental CEQA review are met, further review would be required for continued reliance on the Conformity Review Process.

By amending the existing Zoning Ordinance to provide a new review process and site development standards, the proposed Project would provide for the continuation of existing oil and gas activity, which would have continued even if there were no Project, under current zoning. As such, the Potential Future Oil Development Scenario represents a continuation of existing oil and gas activities that, in conventional CEQA analysis, would be considered baseline conditions. Based on the current permitting in Kern County, the proposed Project's impacts on the existing environment would be beneficial by imposing new site development standards that incorporate more stringent, environmentally protective conditions than exist in the current Zoning Ordinance.

This SREIR takes a more environmentally conservative approach to the impact analysis. The future environmental impacts associated with new oil and gas activities subject to approval by the County, utilizing the new Oil and Gas Conformity Review process, are considered impacts of the proposed Project.

For example, air emissions associated with construction and operation of new wells or new wellbore re-entry activities (e.g., deepening, redrilling, workovers, reworking etc.), all subject to Oil and Gas Conformity Review under the amended Zoning Ordinance, are attributed to the proposed Project even though these emissions have occurred in the past and are likely to occur at the same levels in the future whether or not the Ordinance is amended. In addition, emissions from operation of ancillary facilities are attributed to the wells that receive Oil and Gas Conformity Review, on a per-well basis, even though a specific well may utilize existing ancillary facilities that have emitted in the past and are likely to continue emitting at the same levels in the future, whether or not the Ordinance is amended. Thus, all construction and operational emissions from, and associated with, wells that are subject to Oil and Gas Conformity Review are treated as new emissions of the Proposed Project, regardless of whether or not Countywide emissions would change from historic baseline levels as a result of the amended ordinance.

It should be emphasized that this approach differs from the conventional use of baselines in CEQA impact analysis. In the conventional analysis, the anticipated Countywide emissions after the proposed Project zoning amendments take effect would be estimated, and then the baseline emissions from existing oil and gas activities would be subtracted from post-Project emissions, in order to determine the extent of impacts attributable to the Proposed Project. As a simplistic example, assuming that the average historic levels of oil and gas activities that generate air emissions do not change at all after the Zoning Ordinance amendments take effect, emissions would remain constant at the baseline, or perhaps even decline due to implementation of the performance standards that would be required by the amended ordinance. By definition, so long as the baseline standards were not exceeded, there would be no air quality impacts, even if thousands of new wells were drilled and began operating. By contrast, in the analytic approach in this SREIR, post-Project emissions have been evaluated to identify impacts without subtracting baseline emissions. Thus, even if Countywide emissions remain constant at the baseline, the air quality impacts of the proposed Project would be determined by the total operational emissions of the new wells and ancillary activities approved under the amended Zoning Ordinance.

This analysis is more conservative than the conventional approach, by capturing ongoing environmental effects that otherwise would come under the baseline. Moreover, the conventional approach would not serve the objective of providing an environmental analysis that can be relied on by CalGEM and other responsible agencies in their own permitting and approval processes, as well as by Kern County.

The SREIR applies a similar approach to other categories of environmental impacts, although the details vary for some impact categories. For example, land disturbance, habitat loss, and biological resource impacts associated with construction and operation of wells (and related ancillary facilities) that receive Oil and Gas Conformity review would be considered impacts of the proposed Project. However, land disturbance, habitat loss, and other biological resource impacts associated with pre-existing wells, constructed under the current Zoning Ordinance, are part of the baseline and not impacts of the proposed Project. Unlike air emissions, which are emitted anew each day even if just due to continuing a pre-existing activity, land that has been disturbed remains in its disturbed state unless it is restored. As Communities for a Better Environment v. South Coast Air Quality Management District (2010) 48 Cal. 4th 310 emphasized, EIRs should not use a hypothetical baseline of conditions that do not actually exist; therefore, this SREIR does not assume a pristine, pre-oil and gas landscape where none currently exists. Similarly, the analysis of aesthetics/visual impacts takes into account existing permanent installed facilities and existing disturbed landscapes.

3.5.1 Potential Future Drilling of New Wells

Over the next 25 years, this SREIR conservatively assumes that an average of 2,697 new producing wells per year could be drilled in the Project Area. Tables 3-7 through 3-10 provide an annual breakdown of potential drilling activities for years 2015 through 2040 for the Western, Central, and Eastern Subareas, and for the Tiers. The level of well drilling in any given year may be higher or lower than this average, consistent with the variations in well drilling activities that have historically occurred due to market and other conditions.

Table 3-7: Annual Well Forecast - Project Subareas [(a)]

Well Type	Subarea			Total
	Western	Central	Eastern	
New Producing Wells [(b)]	1,730	131	836	**2,697**
Water Disposal	30	5	13	48
Water Flood Injectors	153	2	3	158
Idle Wells, Non-Cyclic	256	19	105	381
Observation Wells	43	1	13	56

Table 3-7: Annual Well Forecast - Project Subareas [a]

Well Type	Subarea			Total
	Western	Central	Eastern	
Steam Flood Injectors	231	4	69	304
Air Injection	0	0	0	0
Gas Disposal	4	0	1	5
TOTAL NEW WELLS (ANNUALLY)	**2,447**	**162**	**1,040**	**3,649**
Cyclic Wells	977	0	668	1,645
SB 4 Activities	1,050	125	25	1,200
Plugged & Abandoned	1,831	38	352	2,221

Notes:
[a] Source = CEQA Applicant Technical Committee (with County team modifications)
[b] Producing Wells = Oil and Gas, Dry Gas, Dry Hole, and Liquid Petroleum Gas Wells
Key:
SB 4 = Senate Bill 4

Table 3-8: Annual Well Forecast (by Tiers), Western Subarea [a]

Well Type	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5	Total
New Producing Wells [b]	1,630	74	15	10	1	**1,730**
Water Disposal	25	5	0	0	0	**30**
Water Flood Injectors	149	4	0	0	0	**153**
Idle Wells, Non-Cyclic	213	43	0	0	0	**256**
Observation Wells	42	1	0	0	0	**43**
Steam Flood Injectors	228	3	0	0	0	**231**
Air Injection	-	0	0	0	0	**-**
Gas Disposal	4	0	0	0	0	**4**
TOTAL NEW WELLS (ANNUALLY)	**2,292**	**128**	**15**	**10**	**1**	**2,447**
Cyclic Wells	938	39	0	0	0	**977**
SB 4 Activities [c]	989	45	9	6	1	**1,050**
Plugged and Abandoned	1,596	222	12	0	1	**1,831**

Notes:
[a] Source = CEQA Applicant Technical Committee (with County team modifications)
[b] Producing Wells = Oil and Gas, Dry Gas, Dry Hole and Liquid Petroleum Gas Wells
[c] Tier Distribution of SB-4 Activities is assumed to be the same percentage as Distribution of New Producing Wells
Key:
SB 4 = Senate Bill 4

Table 3-9: Annual Well Forecast (by Tiers), Central Subarea [a]

Well Type	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5	Total
New Producing Wells [b]	100	20	5	5	1	131
Water Disposal	4	1	0	0	0	5
Water Flood Injectors	2	0	0	0	0	2
Idle Wells, Non-Cyclic	16	3	0	0	0	19
Observation Wells	1	0	0	0	0	1
Steam Flood Injectors	4	0	0	0	0	4
Air Injection	0	0	0	0	0	0
Gas Disposal	0	0	0	0	0	0
TOTAL NEW WELLS (ANNUALLY)	**127**	**24**	**5**	**5**	**1**	**162**
Cyclic Wells	0	0	0	0	0	0
SB 4 Activities [c]	95	19	5	5	1	125
Plugged and Abandoned	33	5	0	0	0	38

Notes:
[a] Source = CEQA Applicant Technical Committee (with County team modifications)
[b] Producing Wells = Oil and Gas, Dry Gas, Dry Hole and Liquid Petroleum Gas Wells
[c] Tier Distribution of SB-4 Activities is assumed to be the same percentage as Distribution of New Producing Wells
Key:
SB 4 = Senate Bill 4

Table 3-10: Annual Well Forecast (by Tiers), Eastern Subarea [a]

Well Type	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5	TOTAL
New Producing Wells [b]	700	75	50	10	1	836
Water Disposal	11	2	0	0	0	13
Water Flood Injectors	3	0	0	0	0	3
Idle Wells, Non-Cyclic	88	18	0	0	0	105
Observation Wells	13	0	0	0	0	13
Steam Flood Injectors	68	1	0	0	0	69
Air Injection	0	0	0	0	0	0
Gas Disposal	1	0	0	0	0	1
TOTAL NEW WELLS (ANNUALLY)	**883**	**96**	**50**	**10**	**1**	**1,040**
Cyclic Wells	641	27	0	0	0	668

Table 3-10: Annual Well Forecast (by Tiers), Eastern Subarea [a]

Well Type	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5	TOTAL
SB 4 Activities [c]	21	1	0	0	0	25
Plugged & Abandoned	307	43	2	0	0	**352**

Notes:
[a] Source = CEQA Applicant Technical Committee (with County team modifications)
[b] Producing Wells = Oil and Gas, Dry Gas, Dry Hole and Liquid Petroleum Gas Wells
[c] Tier Distribution of SB-4 Activities is assumed to be the same percentage as Distribution of New Producing Wells
Key:
SB 4 = Senate Bill 4

While it is not possible to identify the exact location of each of these future wells, these locations have been grouped into the three Subareas described above. Within each Subarea, future well locations are further predicted to occur by Core Area, since over 95% of historic oil and gas activities occurred within Core Areas, and this pattern is assumed to continue in the future.

3.5.2 Oil and Gas Activities

As described above, the proposed Project consists of both an amendment to Kern County Zoning Ordinance, Chapter 19.98 (Oil and Gas Production) and related sections of the Kern County Zoning Ordinance, and the implementation of future oil and gas development activities expected to be undertaken pursuant to the amended ordinances. Oil and gas activities comprise a number of different components, beginning with geophysical exploration, and ending with well plugging and abandonment. The early stages of well drilling and testing are of short duration, lasting a few days up to a month or more at any specific location, while production may last for many years. Well plugging and abandoning lasts only a few days, and the site is reclaimed or repurposed.

For the purposes of this SREIR, oil and gas activities have been divided into two sets of components: (1) construction activities, which include both initial construction activities (e.g., well pad construction, drilling, and installation of new wells or construction of new ancillary equipment facilities, modification of existing wells and equipment through “reworking” or re-drilling existing wells, and dismantling or removal of equipment and well abandonment); and (2) operational activities, including the routine maintenance and operation of equipment. Construction activities have a limited duration in any one location (e.g., a particular well pad); however, due to the volume of oil and gas activity in Kern County, these construction activities routinely occur throughout the Project Area. The purpose of this methodology is not to imply a specific chronological sequence of events, but rather to group together short-term activities with similar potential impacts for analysis purposes as distinct from long-term activities during production.

Overview of Construction Activities

Exploration and development involves geophysical testing and drilling test (exploration) wells to assess the quality and quantity of oil and natural gas present in a previously undeveloped location either inside or outside the administrative boundaries of an existing wellfield. Assuming successful testing, additional wells are drilled until the extent of the reservoir is determined. The field is then further developed by constructing additional wells and installing gas and oil processing equipment and transportation facilities.

Wells may also need to be "re-worked" during the operating life span of the well, to adjust for evolving field conditions or new technologies (e.g., well stimulation). Finally, decommissioning and abandonment involves well abandonment and plugging activities. Accordingly, while construction activities are considered separately from operational activities because of their limited duration, activities categorized as "construction" occur continually throughout exploration, development, production, and closure.

Itemized Construction Activities

Exploration, development, production, and closure involve the following short-term construction activities. At a particular site, these activities may take place in the order listed below or in a different sequence:

- Geophysical Surveys;
- Well Pad Preparation;
- Testing;
- Access Road Construction;
- Electrical Distribution Line and Substation Construction;
- Drilling;
- Well Completion;
- Construction of Oil, Gas Treatment Facilities;
- Construction of Water Treatment Facilities;
- Steam Generator Construction;
- Construction of Tankage and Containment Structures;
- Pipeline Installation;
- Construction of Sumps, Evaporation Ponds and Percolation Ponds;
- Installation of Produced Water Injection Wells;
- Construction of Fencing;
- Administrative Facility Construction;
- Well Re-Working and Workovers;
- Well Stimulation;

- Decommissioning and Abandonment; and
- Reactivation of Idle Wells.

Itemized Operational Activities

During well operations, when oil is being produced, the following routine operations and maintenance activities occur at well locations:

- Geophysical Monitoring;
- Treatment of Produced Water, Oil and Gas;
- Water Management;
- Enhanced Oil Recovery (EOR) Activities;
- Injection Wells (Class II Fluids);
- Sumps;
- Percolation and Evaporation Ponds;
- Vegetation Control;
- Spill Prevention, Control, and Countermeasure (SPCC) Procedures;
- Non-Hazardous Solid Waste Management;
- Well, Pipeline, Tank and Vessel Testing and Maintenance;
- Centralized Oil/Water Separation;
- Steam Generators;
- Electric Distribution Line and Substation Maintenance;
- Access Road Maintenance;
- Distribution of Crude Oil; and
- Administrative Building and Personnel Housing.

In addition to oil and gas wells, installation and operation of ancillary equipment and facilities is an integral component of oil and gas exploration and production. All wells, for example, are connected by pipelines to tanks that separate oil from the other extracted liquids (primarily "produced water" from the same geologic strata as the oil or gas, along with water and additives that may be injected as steam or liquid to help extract the oil). Wells also have monitoring devices, and may have electric and telecommunication equipment, and waste gas collection lines.

"Tank farms" that include tanks for separating oil and water, and storing both, typically serve several wells and vary in size and distance from wells. Produced water collected in tanks is typically re-used for further extraction purposes, stored in surface impoundments where it percolates into groundwater and/or evaporates, or disposed of by injection well. Some produced water requires treatment prior to reuse for extraction, or disposal, and some produced water is treated and reclaimed for other purposes, as discussed further in Section 4.9, Hydrology and Water Quality, and Section 4.17, Utilities and Service Systems.

Extraction technologies also include injecting large volumes of water (water flooding) or steam (steam flooding) into production strata, and managing the time that each well is active and idle to maximize the recovery efficiency. Additional ancillary equipment and facilities required for these enhanced recovery methods include producing steam, and pressurizing steam or water, typically through larger cogeneration plants serving the wellfields where these techniques are utilized.

Personnel conducting wellfield construction, maintenance, and operating activities are typically dispatched from centralized facilities (most located in Bakersfield), although some workers are staffed onsite, especially at larger oilfields.

More information about each of these Project activities is provided below.

3.5.3 Construction Activities in Detail

Exploration and Development

The purpose of exploratory wells is to find new deposits of hydrocarbons or to define the lateral limits of hydrocarbons outside of a known producing area and then develop the site for production. Activities that occur during this exploration and development process include geophysical surveys, access road and well pad construction, drilling, well completion, and testing, and distribution line construction. In addition, temporary equipment, such as storage tanks and other equipment, are placed in the drilling area.

Once the reservoir boundaries have been established, infield wells may be drilled within the field boundaries to fully develop the reservoir. Activities for infield wells may include well pad construction, access road construction, and flowline construction.

Geophysical Surveys

Geophysical surveys may be conducted to determine the extent of natural gas and oil reserves present, and whether such resources warrant additional development. Geophysical surveys generate low-frequency sound waves by various means, and the data are recorded by small geophones that have been strategically placed within the survey area. The energy source is applied using specialized trucks to vibrate the ground (vibroseis), or detonating charges underground (shothole). Both of these methods include the deployment and recovery of geophone receivers that are connected by cables to a recording station (seismograph) mounted on a specialized truck. The vibroseis technique utilizes truck-mounted vibroseis units to generate vibrations. The shothole technique utilizes holes drilled in a variable spacing pattern, usually less than 60 feet deep and with a diameter of 3 to 5 inches. Explosive charges are placed in the holes and detonated to generate seismic waves that are recorded by the seismograph. Explosive charges are required in areas of steep terrain where a vibroseis source cannot safely operate or where farmers indicate a preference (i.e., orchards where low branches cannot accommodate vibroseis units or tilled fields where vibration will damage crops). Electronic encoded detonation caps and biodegradable charges are used to ensure the safety of shothole operations.

Well Pad Preparation

Preparation of both the exploratory and development well pads begins with clearing and grading an area to accommodate the well and any drilling activities or ancillary facilities that may be required. After the well pads are developed, the drilling rig is moved onto the well pad and set up. Temporary facilities, equipment, and materials necessary for the drilling operation may also be set up and stored on the well pad (i.e., drilling mud supplies, water, drilling materials and casing, crew support trailers, pumps and piping, portable generators, field flares, fuels and lubricants, etc.). Containments (temporary pits, operations sumps, and/or portable tanks) may be set up to store drilling fluids, wellbore cuttings, and drilling wastes. Portable tanks may also be set up to mix and store other needed liquids or slurries, such as drilling fluids and completion fluids.

The size of the well pad is dependent on the size of the drilling rig footprint, the number of wells anticipated to be drilled on the pad, the type of equipment that would be placed on the well during production, the depth of the well, and the number of additional wells (if any) from this well pad. The drilling support equipment is dependent on the depth of the well and the type of activities required for production. For example, a deeper well requiring hydraulic fracturing would necessitate a larger well pad because more space would be needed for vehicles, pumps, and storage equipment. In contrast, a shallower well would require less equipment and, therefore, a smaller well pad.

Because the depth to formation varies throughout the Project Area, the amount of land required for well pad construction varies accordingly. In general, the deepest wells are located in the Central Subarea, and the shallowest wells are in the Eastern Subarea. As discussed in Appendix F of the 2015 FEIR, provided in Volume 4 of this SREIR, existing land use disturbance associated with oil and gas exploration and production activity in each Subarea was analyzed by dividing the total observed disturbance acreage by the number of production wells in the 10 largest oil fields located in each Subarea. This methodology accounts for well pad size and ancillary disturbance variability—such as tanks, roads, and administrative facilities—that reflects construction and operational conditions in each Subarea. The observed average disturbance per production well in each Subarea was further increased to provide a conservative assessment of potential Project impacts. The disturbance acreage that is assumed to occur for each new production well in the Project Area varies by Subarea as follows:

- Western Subarea: 2 acres
- Central Subarea: 3 acres
- Eastern Subarea: 1.2 acres

These estimates assume that each new well would require new land disturbance for well pad construction, ancillary facilities, access, infrastructure, and other construction and operational activities. The actual level of new disturbance associated with each production well would be lower in the event that, as is likely to occur in more developed oil fields, existing disturbed areas, such as existing roads, ancillary facilities, and infrastructure, are used under future conditions. The calculation of potential future disturbance by Subarea is discussed in detail in Appendix F of the 2015 FEIR, provided in Volume 4 of this SREIR.

Testing

After an exploratory or other well is completed, monitoring and sampling is initiated to determine whether the area should be further developed for production. For an exploratory well, oil and water are typically produced into temporary tanks, while any associated gas may be burned off using a permitted temporary flare at the well site, or used to power the artificial lift for the well. For a development well or in-fill activities, the well is connected to the field infrastructure that pipes the production to a centralized facility during the testing phase. These facilities have equipment to separate and process all of the production (oil, gas and water) for sale. The produced oil/water mixture is then separated via gravity or centrifugal separation, and the oil-to-water ratio is recorded.

Access Road Construction

If an existing road cannot be used to access a new well location, a new road would be extended from adjacent existing roads. Access roads are typically 16 to 20 feet in width and vary in length, depending on the distance from an existing roadway. The potential new land disturbance that could be associated with future access road construction is included in the disturbance acreage estimates discussed above and in Appendix F of the 2015 FEIR, provided in Volume 4 of this SREIR. Access road construction typically includes clearing of vegetation and grading to provide a flat surface. Dust suppression and soil compaction activities would also be conducted. Although some access roads may be paved, it is assumed that almost all (95%) of new access roads would be unpaved dirt roads.

Exploratory wells generally would require the construction of new roads, rather than the extension of an existing road. By contrast, for development of in-fill wells, extension of an existing road up to several hundred feet would be typical. Both the roadbed and shoulder areas of all roads would be maintained during drilling and production to provide a smooth surface and adequate drainage. Repairs, such as culvert repairs and replacements, would also correct normal wear and tear or storm damage.

Electrical Distribution Lines and Substations

Distribution lines are used to supply power to individual wells. During exploration, if an electrical distribution line is not readily available, a diesel-powered generator may be used to provide power to a well in a remote location. Depending on the commercial success of the exploration well and the extent of the oil and gas reservoir, if additional wells are drilled, electrical distribution lines would be extended to the new wells. If the existing electrical distribution system is not adequate, additional electrical facilities and distribution systems may be constructed.

Electrical distribution lines would be connected to the public utility transmission grid via a local electrical substation. The California Public Utilities Commission (CPUC) defines distribution lines as electrical lines under 50 kilovolts (kV). CPUC General Order 131-D exempts distribution lines from CPUC review; however, utility companies need approval from local jurisdictions regarding land use.

For the purposes of this analysis, it was assumed that 467 feet of distribution line would be constructed for each well. Distribution lines are assumed to be suspended from wooden poles 30 feet tall. Electrical conductor (wire that conducts electricity) is 12 kV and is stepped down to 480 volts before being connected to individual motors. Electrical distribution poles are typically approximately 200 feet apart and would be scattered throughout the site, depending on the number of wells or other equipment requiring electricity. Distribution poles are assumed to be constructed along the existing access road rights-of-way (ROWs) or within the well pad area. Therefore, ground disturbance for distribution line construction was assumed to be included in the new oil and gas well disturbance acreages.

Activities associated with distribution lines include the installation, use, maintenance, modification, repair, replacement, and removal of subsurface, surface, and aboveground lines. Switching and transformer facilities are also typical oilfield infrastructure to manage electrical distribution facilities. In contrast to onsite "distribution lines" (i.e., below 50 kV), which are extended, as necessary, to supply power to individual wells and equipment, "transmission lines" are defined by the CPUC as 50 kV and above and are used to transport large amounts of power from the source of electricity generation (a power plant) to industrial, commercial, and population centers. Extending existing high-voltage electric transmission lines (i.e., lines above 50 kV) to provide a permanent supply of electricity to a new well pad or facility may be required. However, transmission lines above 50 kV are regulated by the CPUC and would require separate project-level CEQA review. Construction of new transmission lines is not within the scope of this SREIR.

Drilling and Well Completion

Drilling

Well drilling is the process of drilling a hole in the ground for the purpose of extracting crude oil or natural gas resources or for the injection of a fluid from the surface into a subsurface oil or gas reservoir. Drilling may be "exploratory" or "development" (sometimes referred to as "in-fill" drilling. Exploratory drilling is intended to verify where hydrocarbon deposits exist, or to define the lateral limits of hydrocarbons outside of a known producing area (referred to as a "step-out zone"). Development or in-fill drilling is intended to maximize recovery of oil and natural gas within the defined and known subsurface reserves as established during the exploratory phase. Development drilling consists of drilling wells to extract known hydrocarbon resources to efficiently maximize the development of the reservoir or field. Drilling projects are classified as development or in-fill within existing administrative boundaries of oilfields. In addition to exploratory wells, production wells, and injection wells, other wells may include observation wells, which are used to monitor reservoir temperatures, or water monitoring wells, which are used to observe and monitor water quality.

After the well pad is prepared, the drilling rig and associated equipment would be brought to the site and assembled. While the number of workers required for drilling may vary, it is anticipated that 12 workers would be required per well. Due to the complexity of drilling and the hazards associated with leaving a well unattended during the drilling process, drilling operations are conducted 24 hours a day. Night lighting is required in order to maintain continuous drilling operations.

During a standard hydraulic fracturing operation, there are up to approximately 8 to 15 employees on each shift, and usually no more than one shift is needed per day. Additional personnel from the owner/operator may be onsite to observe and run ancillary equipment, as necessary.

Although the depth of each well varies, wells in the Western Subarea average 2,305 feet, wells in the Central Subarea average 10,414 feet, and wells in the Eastern Subarea average 2,220 feet. Depending on the depth of the formation, some wells may take less than 24 hours to drill, while some wells in deeper formations may take more than 60 days to drill. For the purposes of this SREIR, it is assumed that wells take 23 days to drill on average, ranging from a minimum of 18 days to a maximum of 28 days, depending on well depth. While drilling continues, temporary oil, water, and gas handling equipment, such as tanks, vessels, pumps, and compressors, would be located onsite, as needed. Depending on the location of the operation and the intensity of activities in the area, drill rigs would be powered by diesel- or gasoline-fueled generators or by local electrical service, where available, as described above in the “Distribution Lines” subsection.

All drilling activities would occur on the well pad.

Well Completion

After a well has been drilled, well completion activities are conducted. Well completion activities include the following:

- **Casing and Cementing:** Production casing (metal pipe) is set into the wellbore at the appropriate depth in compliance with CalGEM requirements. Drilling mud is first pumped through the casing to ensure consistent and unrestricted circulation of fluids in the wellbore. Cement is then pumped into the casing via a cement truck, the volume of which depends on the specific requirements of that well. When the cement reaches the bottom of the casing, it flows out of the casing and up into the space between the wellbore and casing until it reaches the surface. This process encapsulates the casing in a cement sheath, isolating the casing from the surrounding geologic formation. The hydraulic isolation formed by the hardened cement protects groundwater by preventing oil and gas reservoirs and the groundwater from contaminating each other and seals the hydrocarbon zone. This seal allows the drilling crew at the surface to control the fluid extraction process. Casing and cementing is completed as stipulated by CalGEM regulations and in accordance with Title 14 CCR, Division 2, Chapter 4, Subchapter 1, Article 3, Sections 1722, 1722.2, 1722.3, 1722.4, 1722.5 and 1722.6. CalGEM engineers are required to be present for tests and other operations, and additional casing is required in freshwater zones to protect water quality, as well as to seal off anomalous pressure zones and isolate production.

- **Open-Hole vs. Cased-Hole Completion:** An “open-hole” completion refers to a well that is drilled to the top of the hydrocarbon reservoir. The well is then cased and cemented with the only hole in the casing being at the bottom. Also known as “top sets” and “barefoot” completions, open-hole completions are used to reduce the cost of casing where the reservoir is consolidated (e.g., where a reservoir is encapsulated in a solid geologic formation, such as a larger reservoir encased in bedrock). In contrast, a “cased-hole” completion requires casing to be run farther into the reservoir. Special tools, such as perforation guns, are then lowered into the casing until they reach reservoir level, and used to perforate the casing and cement, thereby creating holes into the reservoir. The holes in the casing and cement allow hydrocarbons to flow into the casing and up to the surface. Cased-hole completion is effective when the reservoir is less consolidated (e.g., when there are dispersed pockets of hydrocarbons throughout the reservoir).
- **Sand Control Techniques:** Depending on the formation, a filtration system may be required to allow production of formation fluids while restricting the entry and production of formation sand. If necessary, a casing liner, which is a type of casing with holes or slots placed opposite a producing formation, is used to prevent sand from entering the well. Additionally, gravel packing is a method used in which a slotted or perforated liner, often wire-wrapped, is placed in the well and surrounded by gravel. If open-hole, the well is sometimes enlarged by underreaming at the point where the gravel is packed. The mass of gravel acts as a filter, which excludes sand from entering the wellbore, but allows the continued flow of hydrocarbons.
- **Wellhead Installation:** Wellhead installation (also known as a “production tree” or “Christmas tree”) and pumping unit installation are the final steps in the well completion process. The wellhead device includes casing heads and a tubing head and allows operators to control subsurface conditions from the surface of the well.
- **Flowline Installation:** Flowlines are typically built for new wells and are installed aboveground on concrete or wooden sleepers or metal pipe supports. The pipeline runs from the nearest gauge station to the edge of the well location. Gauge stations serve as collection points for production fluids from nearby wells and allow for the flow testing (oil and water) of each well. The final section of flowline connecting to the wellhead is installed after the drilling rig finishes drilling the well and moves off the location.
- **Artificial Lift System:** Most wells require some form of artificial lift to bring produced fluids from the reservoir to the surface and move the fluids to a tank farm. The most common type of artificial lift is the pumping unit working in conjunction with a sucker rod pump system. These systems consist of a prime mover (usually an electric motor), a gear reducer, the pumping unit that translates the rotating motion of the electric motor into reciprocating motion, the sucker rod string that extends down the well bore inside a production tubing string, and the subsurface pump located near the bottom of the well. A production rig is usually required to install the downhole components of the system (tubing, rod string, and pump). The pumping unit is installed immediately adjacent to the wellhead such that the reciprocating motion will alternate between lifting and lowering the rod string. A column of production fluid will be further lifted inside the tubing string with each stroke

of the pumping system. Artificial lifts may be powered by electrical power or in remote locations where electrical infrastructure does not exist, by internal combustion engines. Other types of artificial lifts employed are electrical submersible pumps and gas jacks.

- **Electrical Power**: Electrical power to operate the pumping unit motor is required at each well. Power is distributed throughout the oilfield at the 12kV level and then stepped down to 480 volts before connection to individual motors. The appropriate motor starter equipment is installed near each well.
- **Workover Rig**: Well completions may occur with the drilling rig onsite or the drilling rig may be removed. A workover rig could replace the drilling rig, or the completion design may be rigless.

Oil and Gas Treatment Facility Construction

Production fluids from the wells must be separated into the individual components prior to sale or custody transfer to pipeline systems. In larger oil fields, produced gas is typically first separated from the oil and water liquids at a centralized gas treatment plant. The liquid oil and water (typically a mixture composed of 3% to 10% oil and 90% to 97% water) are further separated at oil treatment facilities, such as tanks in smaller operations, or in treatment plants in larger oil fields. The oil, gas, and produced water separation and treatment process and related facilities are described in more detail below. The potential new land disturbance that could be associated with future oil, gas, and produced water treatment plants and facilities is included in the disturbance acreage estimates discussed above and in Appendix F of the 2015 FEIR, provided in Volume 4 of this SREIR.

Water Treatment Facility Construction

Water treatment facilities are generally used to treat produced water for reuse in enhanced oil recovery (EOR) activities. EOR treatment generally involves water softening or removal of salts and other constituents for steam generation purposes. As discussed in Section 4.9, Hydrology and Water Quality, produced water is also treated and blended with other water sources by the Cawelo Water District in the Eastern Subarea for agricultural irrigation purposes. Depending on facility design and intensity of the treatment process, the facilities can also provide for reuse of the produced water, including, but not limited to, agricultural irrigation, land restoration, and animal stock drinking water. It was assumed that for every 27 wells, a centralized water treatment plant would be constructed, and the average water treatment plant would require 0.11 acres of disturbance. The potential new land disturbance that could be associated with future EOR and agricultural reuse produced water treatment plants and facilities is included in the disturbance acreage estimates discussed above and in Appendix F of the 2015 FEIR, provided in Volume 4 of this SREIR.

Steam Generator Construction

Thermal enhanced oil recovery production techniques may require the use of steam, which may necessitate the installation of steam generators. Steam generators are large heaters that generate steam, usually from produced groundwater. These generators are typically powered by electricity or natural gas. A thermal generator may be installed at an individual injection site or built in a centralized location to reach multiple injection sites. A water storage tank would be connected to the thermal generator, and aboveground pipelines would connect the thermal generator to the injection sites. The decision to construct a centralized steam generator would be based on whether cogeneration facilities were or were not located nearby, and whether it is more economically viable to build a centralized steam generator rather than a cogeneration facility. The number of wells that can be served by a single steam generator is determined by the amount of steam required to effectively heat the reservoir and the size of the generator unit itself. For the purposes of this SREIR, it was assumed that for every 30 to 60 wells, a centralized steam generator would be constructed. The average industrial boiler system would require 1 acre of disturbance per generator. Generators may be co-located with other equipment (e.g., separation tanks, etc.).

Some existing oil and gas production operations utilize cogeneration facilities to provide the steam required for EOR. However, it has been more than 10 years since the last cogeneration facility was proposed and approved. In the intervening years, the electricity markets have changed substantially in ways that make it less attractive to construct new cogeneration facilities in many locations. Due to these changes, it is uncertain whether any new cogeneration facilities would be proposed, and any estimate regarding the number or technology for future cogeneration facilities would be entirely speculative. For these reasons, cogeneration facilities proposed in the future, if any, will require a CUP and separate CEQA review, as appropriate.

Construction of Tankage and Containment Structures

In compliance with EPA SPCC requirements and CalGEM facilities regulations, secondary containment structures would be constructed around tanks, chemical containers, etc., to ensure that oil or chemicals are not discharged into natural drainage ditches and the environment. Corrugated pipe filled with concrete, concrete berms, and earthen berms are typically used and are designed and constructed to contain a minimum of 110% of the volume of the largest tank that is located within the facility. Various sizes of tanks typically are utilized to store oil prior to offsite transport. Such storage facilities can range in size from small to large tank arrangements with supportive piping and conveyance facilities.

Pipeline Installation

Pipeline installation activities include new construction and maintenance of pipelines, access roads, related support facilities (e.g., aerial and ground markers, spans, meter sites, etc.), storage tanks, valve stations, regulators, and compressor stations. Pipelines are installed to transport produced oil, water, and natural gas into storage tanks or separation tanks for further processing. Pipelines are also required in order to pump water, steam, or other substances into the reservoir during well stimulation and EOR procedures. Construction of the following types of pipelines is considered within the scope of this Project:

- **Flowline or Injection Line**: any pipeline that connects the wellhead to a manifold (header) or to production facilities.

- **Gathering Line**: a pipeline (independent of size) that transports liquid hydrocarbons between any of the following: multiple wells, a testing facility, a treating and production facility, a storage facility, or a custody transfer facility.
- **Header**: a pipe arrangement that connects flowlines from several wellheads into a single gathering line. A header has production and testing valves to control the flow of each well, thus directing the produced fluids to production or testing vessels. Individual gas/oil ratios and well production rates of oil, gas, and water can be assigned by opening and closing selected valves in a header and using individual metering equipment or separators.
- **Pipeline**: a tube or system of tubes used for transporting crude oil and natural gas from the field or gathering system.

In general, most onsite pipelines, such as those described above, are installed aboveground but may also be installed underground, if necessary (e.g., to cross a roadway). Some portions of pipelines are installed aboveground on the surface of the well pad and do not require further ground disturbance if production facilities are not co-located at the well pad. However, additional clearing and grading would be required for pipeline segments that cross outside of the well pad area. In these cases, the pipeline would generally run along the existing roadway, if possible. Permanent disturbance would occur from sleepers, pipe racks, and any new access roads that may need to be constructed. If the pipeline runs under a roadway or is required to be placed underground, the construction process would involve clearing, trenching, shoring (as appropriate), pipe laying, pipe zone backfill, trench backfill, and final grading. Although buried pipelines would create more temporary disturbance than aboveground installations and require more earthmoving, disturbance would be temporary. For excavation, repair, or replacement of transmission lines, a width of 100 feet or less is typically required for pipelines. Equipment may include a crane, backhoe, flatbed trucks, welding equipment, pick-up trucks, and additional personnel. The duration varies with the length and size of the transmission line being replaced or repaired. Cathodic devices may also be installed and maintained to protect pipelines from corrosion as a result of low pipe to soil electrical potential.

A pipeline corridor width of 20 feet or less is typically required for pipeline installation. Depending on the size and nature of the pipeline, construction equipment may include a crane, backhoe, flatbed trucks, welding equipment, pick-up trucks, and additional personnel. For the purposes of the EIR, it was assumed that the workers required for pipeline installation activities are included in the workforce numbers for well pad construction, drilling, and completion activities. The potential new land disturbance that could be associated with future pipeline construction is included in the disturbance acreage estimates discussed above and in Appendix F of the 2015 FEIR, provided in Volume 4 of this SREIR.

Construction of distribution pipelines (i.e., pipelines intended to transport crude oil to an oil refinery) was not included in these estimates. Distribution pipelines were assumed to be existing and would not be constructed under this proposed Project.

Cathodic protection systems may also be installed and maintained to protect pipelines and well casings from corrosion. Cathodic protection is carried out by including the metal to be protected as part of a low voltage electrical circuit (as the cathode) along with a separate sacrificial metal (as the anode). The anode material is more easily corroded and prevents the pipeline or well casing from degradation by soil side corrosion.

The type of cathodic protection used varies by location and field conditions. Typical groundbed designs include both impressed current and galvanic/sacrificial anodes. Common impressed current anodes are tubular and solid rod shapes or continuous ribbons of various materials, including high silicon cast iron, graphite, mixed metal oxide, platinum and niobium coated wire, and other materials. The most common galvanic/sacrificial anode used is magnesium. Primarily used for pipeline cathodic protection, the magnesium anodes are manufactured in various sizes and are prepackaged in gypsum backfill to maintain low resistance to earth. Anodes may be arranged in vertical or horizontal/distributed groundbeds. Typical vertical groundbed installations vary in depth from 10 to 420 feet and are installed by use of auger or drilling equipment with a diameter of <12 inches. Typical horizontal/distributed groundbed installations vary in depth from 8 to 10 feet and may be installed by use of trenching equipment adjacent to the pipeline within the pipeline corridor.

Construction of Sumps, Evaporation Ponds and Percolation Ponds

A sump is a lined or unlined excavated depression in the ground that collects crude oil, produced water, or solids, such as drilling muds or cuttings, in oil producing fields. Drilling sumps are utilized to collect drilling fluids and cuttings (collectively known as “drilling muds”), which are produced during drilling operations. Operations sumps are utilized to store fluids and solids, which are produced during the life of the operational well as well as potential workover activities. Sumps are used in combination with other separation and treatment facilities and may be in greater or lesser use depending up the size of the operation. For example, larger operators rely more heavily on aboveground tank systems, while smaller operators rely more heavily on sumps due to the dispersed nature of production

A percolation pond is used to dispose of water associated with hydrocarbon production by percolation into the soil. A natural or artificial evaporation pond is a pond with a large surface area that is designed to efficiently evaporate water by exposure to sunlight. Percolation and evaporation ponds vary in size, but are typically between 2 and 5 acres and can be as shallow as 5 feet deep. Drilling sumps and operations sumps and ponds are subject to state and, where applicable, federal permit requirements. In general, the use of drilling sumps has been reduced in the Project Area as well field operators increasingly utilize closed-loop drilling systems that avoid mud or fluid discharges to land during the well drilling process.

Installation of Produced Water Injection Wells

Injection wells used for disposing produced water are sited in underground formations, such as sandstone, that are porous and permeable enough to accept injected fluids or gas. Rock formations in the zones that are utilized for injection are covered by impermeable formations, such as shale, in order to isolate the injected liquids from potential migration to other formations.

Injection wells are drilled, cased, and cemented similar to production wells, or in some cases, production wells are converted into injection wells. Several tests are then run to make sure the injection well is operating properly and the injected fluids are confined to the intended injection zone. As discussed in Section 4.9, Hydrology and Water Quality, all injection wells must be permitted by CalGEM in accordance with federal requirements under a primacy agreement with the EPA.

Fencing

Fencing may be installed around the perimeter of a site to provide for security, health and safety, as well as for environmental protection to prevent unauthorized access that could cause habitat disturbance, such as off-highway vehicle activity. Various types of fences are utilized. Use of existing roads and some off-road travel would be required in order to access the perimeter fence or for fence installation. In larger extraction-level operations, fencing may not be required because wells are in remote locations and operations are conducted over 24 hours. Therefore, there are fewer security issues in these areas. In contrast, in more urban settings, such as areas within the Metropolitan Bakersfield Planning Area, fencing is required for security and aesthetics.

Administrative Building Construction

Most employees doing construction and maintenance work on wells and oilfield equipment are dispatched from central contracting facilities located in Bakersfield. Some staffed administrative offices are located in wellfields, particularly in more established Tier 1 areas. Administrative offices typically range from 1,000 to 10,000 square feet, depending on the size of the development and number of day-to-day personnel. Future development would rely mostly on existing employee and administrative staffing infrastructure. In addition to office space, an administrative office in an oilfield could include control and monitoring equipment, material storage, an equipment warehouse, restrooms, and a kitchen.

The area for the administrative office would be cleared and graded. An administrative office would also require the installation of a septic system (or connection to sewer service if available), water connection, electrical and telecommunication hook-ups, parking lot, and access roads.

Equipment List

Section 4.3, Air Quality, includes an estimate of equipment type, quantity, and hours per day required for grading, earthwork, and facility construction.

Well Re-Working and Workovers

During production, construction activities include well re-working and workovers. Well re-working and workover construction activities are implemented on existing well pads. A re-work or workover operation generally consists of a rig, support trucks, portable tanks, pumps, and various other equipment (depending on the complexity of the planned work). Most of the portable engines used in these operations are regulated by the California Air Resources Board’s portable engine program.

Well re-work typically lasts for a period of a few days; however, some large-scale jobs can take a week or more. Well re-working requires filing a Notice of Intention with CalGEM for well changes, such as changing the well casing, re-perforating, plugging to produce from shallower levels, and redrilling including deepening and side-tracking. Well workovers are more routine well maintenance activities, including liner replacement, casing repairs, pump repair or replacement, well stimulation, and well clean-out (the removal of sand, sediment, or debris build-up or equipment). In an effort to reduce habitat disturbances, existing well pads are used, or sometimes extended, to perform remedial well work. Extensions are only performed if it is necessary to provide a safe well-workover environment.

Ancillary Facility Expansion or Replacement

Over time, existing ancillary facilities may need to be expanded or replaced to process production fluids. Expansion may be needed to support drilling of additional wells or because older wells mature, changing the oil/water mixtures and thus causing changes to the handling capacity of the ancillary facilities. Ancillary facilities may also need to be replaced due to age of the equipment, which can diminish efficiency and reduce overall processing capacity. The expansion or replacement activities may include expanding the footprint of an existing plant to install new equipment such as tanks, vessels, electrical distribution systems, liquid and gas gathering pipeline systems, and oil/water/gas separation and treatment facilities. A typical expansion or replacement would result in temporary and permanent disturbances of varying extent, depending on the site circumstances and size of the expansion project.

Site preparation activities for expansion or replacement projects would be very similar to activities for building a new plant or facility and would include activities such as clearing, grading, construction of tanks, piping, vessels, steam generators, and utilities. Construction of an expansion or replacement facility could result in new land disturbance, which is conservatively assumed in this SREIR to be permanent.

The potential new land disturbance that could be associated with future expansion or replacement facility construction is included in the disturbance acreage estimates discussed above and in Appendix F of the 2015 FEIR, provided in Volume 4 of this SREIR.

Well Stimulation Treatment

Well stimulation can be conducted as part of the well completions process or as part of a well work-over process. This SREIR presents the well stimulation practices, including hydraulic fracturing, used in Kern County and as managed by CalGEM. Hydraulic fracturing as conducted in other states has different characteristics and, therefore, different environmental impacts. Practices utilized in other states are summarized in Appendix U of the 2015 FEIR, provided in Volume 4 of this SREIR.

Decisions on whether a well stimulation operation is required are generally dictated by the geologic characteristics of the reservoir. Stimulation is performed on a well to increase or restore production from new or under-producing existing wells. Public Resources Code Section 3157 of Division 3, Chapter 1, as amended, defines oil and gas well stimulation as “any treatment of a well designed to enhance oil and gas production or recovery by increasing the permeability of the formation. Well stimulation treatments include, but are not limited to, hydraulic fracturing treatments and acid well stimulation treatments. Well stimulation treatments do not include steam flooding, water flooding, or cyclic steaming. Likewise, well stimulation treatments do not include routine well cleanout work, routine well maintenance, routine removal of formation damage due to drilling, bottom hole pressure surveys, or routine activities that do not affect the integrity of the well or the formation. Depending on the type of formation and the current state of the wellbore, only one of the following common well stimulations treatment methods may be required on any given well:

Hydraulic Fracturing

Hydraulic fracturing is a type of well stimulation process conducted as part of the well completion process used after drilling and before production. It is designed to open permeable fracture pathways in the hydrocarbon-bearing geologic formation and entails the injection of “fracture fluid,” which is generally composed of water, a proppant (usually sand or ceramic beads) and carrier fluids (typically proprietary chemicals designed to enhance recovery yields), into a well bore and into the geologic formation to increase the flow of hydrocarbons. Prior to conducting a hydraulic fracturing job, a model is developed that provides guidance on how much fluid and pressure is needed to generate a fracture of a specific desired length. Hydraulic fracturing is then performed in three steps. First, a large amount of hydraulic fracturing fluids is pumped into the well. The high-pressure of the hydraulic fracturing fluids and the continual pumping increases the pressure in the well, eventually clearing or reopening the pore space of the reservoir rocks. This process is carried out until the fracture reaches the desired length. Second, fracturing fluid and propping agents are introduced into the well to extend the breaks and pack them with proppants, or small spheres composed of quartz sand grains, ceramic spheres or aluminum oxide pellets, that hold the fractures open after pumping has ceased. This prevents the geologic overburden from forcing the newly induced fractures closed and allows the hydrocarbons to flow through the open cracks in the reservoir rocks into the well. Third, the well is backflushed to remove the hydraulic fracturing fluids. The hydraulic fracturing fluids are either treated and recycled or disposed of along with other oil production by-products. Other well stimulation techniques place various chemicals in the well to react with well bore scale or the productive formation to allow increased well production. Well stimulation can occur multiple times during the well’s productive life.

Kern County completed a study in June 2015 with the following objectives:

- Identify differences in the most prominent plays across the nation;
- Identify the subsequent drilling and stimulation techniques that would apply to wells being drilled in Kern County as compared to those in other shale plays and conventional oil and gas operations conducted across the nations; and
- Highlight the impact differences between them.

One key factor identified in the study was that drilling in Kern County associated with hydraulic fracturing is vertical (or follows conventional methods). The study is attached as Appendix U and is associated with Section 4.9, Hydrology and Water Quality.

Frac-Packing

Frac-packing is another type of operation that can be defined as a well stimulation treatment, depending on how the operation is designed. The frac-packing treatment combines a hydraulic fracturing process with a gravel pack process.

Conventional gravel pack operations are not classified as well stimulation. A gravel pack is a sand control method used to prevent the flow of formation sand into the producing well. In gravel pack operations, a steel screen is placed in the wellbore and the surrounding annulus is packed with prepared gravel of specific size designed to prevent the passage of formation sand. The gravel is circulated into place at pressures below the fracture gradient of the formation. The gravel pack helps prevent formation sand from obstructing the well bore. This method also helps to prevent damaging equipment and having to dispose of the formation sand after it is separated out of the hydrocarbons produced from the well.

By contrast, in frac-packing operations, the gravel pack is pumped in under pressures high enough to fracture the formation. The operation can be used to create a wider radius screen in formations with unconsolidated or poorly consolidated sands. Depending on how the operation is designed, the frac-packing operation can generate reservoir stimulation effects.

Acid Fracturing and Acid Matrix Stimulation

The primary type of acid-based well stimulations consist of acid fracturing and matrix acidizing. Acid fracturing is the pumping of acid at pressures that exceed the reservoir fracture gradient into the well to dissolve limestone, dolomite, and calcite cement within the reservoir rocks. A matrix acid job involves pumping acid into the well so that it fills the pores of the reservoir rocks. The acids then modify the permeability of the formation by dissolving natural solids that are inhibiting the permeability of the rock. The process enlarges the pores of the reservoir and stimulates the flow of hydrocarbons. Matrix acidizing is regulated as a form of well stimulation under SB 4 if the volume of acid used exceeds the Acid Volume Threshold (as defined in CalGEM regulations, 14 CCR 1761 (a)(3)), unless the treatment as designed does not enhance production or recovery by increasing the permeability of the formation. (Note: Acid may also be injected at lower volumes for well maintenance, which does not increase formation permeability and is not considered a form of well stimulation.) The difference between matrix acidizing and fracture acidizing is that matrix acidizing is done at a low enough pressure such that the reservoir rock is not fractured. In contrast, fracture acidizing involves pumping highly pressurized acid into the well, such that the reservoir rock is physically fractured. Fracturing the reservoir rock dissolves the impermeable sediments, thus creating channels through which hydrocarbons flow.

Hydrochloric acid is a common type of acid used during matrix and fracture acidizing, which removes carbonate reservoirs, or limestones and dolomites, from the rock. Also, when hydrochloric acid is combined with a mud acid, or hydrofluoric acid, the mixture can be used to dissolve quartz, sand, and clay.

In order to protect well integrity, inhibitor additives are introduced to the completed well to prohibit the acid from breaking down the steel casing. Also, a sequestering agent can be added to block the formation of gels or precipitate of iron, which can clog the reservoir pores during an acid job.

After an acid job is performed, the used acid and sediments removed from the reservoir, known as flowback fluid, are washed out of the well. Flowback fluid from well stimulation operations can be handled in several ways. In mature, developed field operations, the most likely scenario is that the well is connected to the field's water handling system, which would pipe the flowback fluid directly into this system. Once it is co-mingled with other fluids and treated, it is disposed of using the common disposal practice of that field. As discussed elsewhere in this document, fluid disposal could be facilitated through waste injection wells or percolation ponds.

Based on data compiled from FracFocus, in 2012, a total of 936 wells in Kern County were subjected to well stimulation treatment regulated under SB 4 (i.e., hydraulic fracturing, acid fracturing, and acid matrix stimulation), including 900 wells in the Western Subarea, 35 wells in the Central Subarea, and one well in the Eastern Subarea. The levels and distribution of SB 4 regulated activity in the County would likely be similar in future years. However, to be conservative, an average of 1,200 wells subjected to well stimulation treatment was assumed in the future activity projections (see Table 3-7).

Decommissioning and Abandonment

Wells undergo plugging and abandonment once they can no longer perform their intended purpose and are no longer otherwise needed. Idle wells that are not yet plugged and abandoned must also be maintained in compliance with CalGEM regulations.

In decommissioning a formerly producing oil well, equipment such as pumping units, well cellars, pipelines, and other associated infrastructure would be disassembled and salvaged or appropriately disposed of. Plugs of cement are placed across specified intervals in the well casing to isolate oil and gas zones and to prevent degradation of useable waters. The well casing is cut off below the surface, sealed with a cement plug, and a steel plate is welded across the top of the casing. The well pad location is then restored to grade and allowed to revegetate. Typical construction equipment, such as bulldozers, motor graders, front end loaders, cement and dump trucks, and well workover rigs, would be utilized to accomplish this work. Work is typically restricted to the pre-disturbed areas of the well pad, but some well plugging and abandonments require expansion of the existing well pads to accommodate equipment. Re-abandonment of a well may be required when there is evidence that the original plugging abandonment no longer retains its integrity.

Facilities such as production test setting, including pipe headers, tank farms, valve stations, or pipelines that are no longer needed for operations are dismantled and removed. The length of time necessary to decommission a facility depends on the size.

Decommissioning and abandonment includes closure of sumps when no longer required. Two types of sumps are used in typical oilfield operations: drilling sumps and operations sumps. Their respective uses and closure are described below:

1) Drilling sumps are utilized to collect drilling fluids and cuttings, collectively known as "drilling muds," which are produced during drilling operations. Drilling sumps are typically located adjacent to the well pad and can vary in size, depending on the depth of the well. Drilling sumps are regulated by CalGEM pursuant to 14 CCR Chapter 4, Subchapter 2, Article 3, Section 1770(c) and 1776(a) and (b). The disposal of drilling muds to land is covered under the State Water Resources Control Board State General Order 2003-0003-DWQ for low threat discharges to land and requires sumps covered under this order to be constructed in uncontaminated soils. The drilling muds are non-hazardous and do not contain halogenated solvents. Drilling muds must first be dried prior to back-filling, and the bottom of the sump must be at least 5 feet above groundwater levels. Fluids must be removed from the drilling sumps within 30 days of completion pursuant to CalGEM sump requirements. Drilling sumps must be restored to pre-construction state within 60 days of completion or abandonment of a well pursuant to CalGEM well site and lease restoration requirements.
2) Operations sumps are utilized to store fluids and solids, which are produced during the life of the operational well as well as potential workover activities. Operations sumps can range from small pits located next to the well, to centralized sumps that collect workover fluids at the well site and for transfer to centralized sumps for processing. In accordance with CalGEM Assembly Bill (AB) 1960 regulations, fluids from operations sumps must be removed from the sump within 14 days of completion of workover activities.

Decommissioning and abandonment also includes removal of cathodic protection systems, when no longer required. Cathodic protections systems, such as sacrificial anode beds or deep cathodic protection wells, are located throughout Kern County oilfields. Eventually, these systems become depleted and no longer function. When these systems are no longer functional, the cathodic protection wells must be properly abandoned to protect the environment. Kern County Ordinance G-5006 regulates abandonment of deep cathodic protection wells (>50 feet), and permits to abandon these wells are obtained from the Kern County Environmental Health Services Division. Abandonment activities include those actions typically associated with plugging and abandonment of an oil well and site restoration.

Reactivation of Idle Wells

CalGEM defines an idle well as a well that has not been injected into or produced for six consecutive months. Idle wells are created when a well is uneconomical to operate due to the cost of needed repairs, low production rates, or a low price of oil. However, depending on economic conditions, an idle well may become economically viable in the future. Reactivation of an idle well may range from simple activities, such as replacement of a well pump, to well deepening, sidetracking, or re-working.

Project Operational Activities

Project operational activities may include: geophysical monitoring; operation of EOR facilities and production facilities (e.g., tanks, compressors, generators, heater treaters, free water knockout facilities, etc.); water, extraction, use and disposal combustion, steam, gas, and chemical flood projects; pipeline replacement or repair; operation, maintenance, demolition, and removal of equipment, buildings, warehouses, storage yards, offices, and other structures, berms, percolation ponds, fences, distribution lines, and other facilities; production activities; responses to and remediation of spills or emergencies; hydrotesting and other non-destructive testing of pipelines, tanks, and vessels; expansion of active well locations to provide safe well-workover activity; brush and weed removal around production equipment; maintenance of pipeline ROWs; and access road maintenance and use.

Geophysical Monitoring

Geophysical monitoring wells are used to monitor the orientation (azimuth and dip), volume, complexity, and approximate location of fractures in the earth's crust (both natural and man-made). The equipment used is a highly sensitive electric level, containing an electrically amplified fluid filled with bubbles. When the instrument tilts, the bubble shifts to one side to indicate the direction of the shift. These wells are typically installed on the corner of existing well pads and do not result in any new surface disturbance.

Treatment Processes, Equipment, and Facilities

A variety of surface facilities support oil and natural gas processing and storage. Depending on the intensity of development and the location of a wellfield, centralized treatment facilities may or may not be constructed. Treatment facilities may be developed with various sizes of tanks, which are utilized to store oil prior to offsite transport, and can range in size from small to large tank arrangements with supportive piping and conveyance facilities.

In addition, the nature of a produced substance dictates the type of facilities required. For example, in many areas in Kern County, an oil/water mixture is produced. The ratio of oil to water differs and is determined during testing. The oil and water must be treated (i.e., separated) so that each substance can undergo further treatment to prepare the oil or water for sale, or to prepare the water for reuse in further production operations, for other recycling uses or for disposal. If natural gas is present in the produced oil/water mixture, the gas may be burned off, re-injected into CalGEM-approved gas disposal wells, treated for sale, or used as fuel for various production activities. Although the majority of the extraction operations in Kern County are oil production, many wells produce some quantity of natural gas, which may be made available for sale or other use.

Treatment of Produced Fluids

Produced fluids from multiple wells are piped to a centralized production header into a gathering line before entering a separator. In some cases, a test header allows the diversion of fluids from a single well through a well test station. The well test station allows the testing of the well quality and flow characteristics. Once the fluid passes through the well test station, it is typically directed back to the gross line and commingled with the other fluids. Fluids from the gross line are then piped into separators to perform an initial separation of the oil, gas and water. Gas is typically separated earlier in the process by using a larger tank to drop the pressure, thus allowing the gas to break out of the mixture. The remaining oil and water separate from each other as they settle in the "knock out" vessel or tank. Oil is lighter than water, so it rises to the top of the oil/water mixture (referred to as gravity separation). The water can be removed from the bottom of the tank and the oil emulsion skimmed from the top of the tank.

Water Treatment

As described above, the produced oil, gas, and water are separated from each other before the produced water to be used for EOR or agricultural reuse undergoes further treatment. To further separate the oil and water, the water flows through or is transferred between a series of separator tanks. As the water passes from one tank to the other, it passes through filters, often manufactured out of sand, diatomaceous earth, or walnut shells. The oil molecules are larger than water, such that most of the oil adheres to the filters, and the water passes through to the next tank. Air or dissolved oxygen also may be added to produced fluids to encourage separation of oil and water. This process is repeated until the water is treated to the desired level, depending on its final disposition—either reuse of disposal. Different types of facilities are required depending on the final use of the water. These facilities typically consist of a series of tanks, filters, and gathering systems to collect and transport the produced water that is removed from oil. Produced water may also be transported, via truck, to other, existing produced water treatment facilities. These other types of water treatment facilities may require additional capacity to treat produced water prior to reuse or disposal. This could involve expansion of the existing facilities, such as waterflood or steamflood plants that supply injection water or steam for EOR operations; drilling additional EOR injection wells; modifications to increase the pumping capacity, pipeline, and distribution systems; and/or converting existing wells from production to injection. Depending on the facility design, the facilities can also provide for the reuse of treated produced water, including but not limited to, agricultural irrigation, land restoration, and animal stock drinking water. For more information on produced water reuse and disposal, see the Water Management section, below.

There are four basic physical/chemical treatment processes that allow produced water to be reused in Kern County and surrounding areas with the following end uses: (1) steam generation; (2) agricultural irrigation; (3) aquifer recharge; and (4) surface discharge. These processes increase in complexity and cost from (1) to (4) in accordance with operational and regulatory standards. Although generalized here, produced water treatment processes are based on field-specific characteristics (e.g., water quality parameters of produced water, its possible use considering the treatment available, and end user availability, agreements, and regulatory concerns) so it should not be assumed that the same treatment processes can be adopted uniformly throughout Kern County.

There are multiple ways of treating produced water for steam generation, which can involve the following steps:

1) Collection of water from the bottom of primary, secondary, and tertiary oil/water separation tanks and vessels. This is usually accomplished by gravity flow.
2) Water nominally containing 200 parts per million (ppm) of free oil content is fed to various types of flotation systems. Such systems rely on gas bubble creation and injection into the water. These bubbles enable small droplets of free oil to accumulate and rise to the surface, where they are skimmed off. A polymer chemical may be injected to aid this process.
3) The water, now containing nominally 20 ppm of free oil, is then sent to an oil removal filter. Such filters often include ground walnut shells, or a walnut/pecan mixture, but multimedia (anthracite/ garnet) and other types of filters can be utilized. The filters will reduce free oil content down to less than 5 ppm.
4) The de-oiled water is now sent to ion exchange softener vessels, which usually include both a primary and secondary (polisher) softening step. The primary will usually be a strong acid cation softener, which is regenerated using concentrated salt brine. The polisher can be either another Strong Acid Cation softener, or a Weak Acid Cation softener. Weak Acid Cation softeners are regenerated using acid and caustic.
5) The softened water is stored in tanks, ready to be pumped to steam generator or cogeneration sites.

Treatment of produced water for agricultural irrigation (e.g., Chevron's Kern River field) includes steps 1 to 3 above, but not steps 4 to 5 because produced water from this field is often low in mineral content. Even so, the permit to discharge this water to the Cawelo Water District relies on dilution of certain mineral constituents with fresh water provided by the District. Dilution takes place in Cawelo Reservoir B.

Treatment of produced water for aquifer recharge (e.g., Chevron's San Ardo Field in Monterey County) generally involves the following steps:

1) Collection, flotation, and filtering, as per steps 1), 2), and 3) above;
2) Cooling;
3) Degasification, through the addition of acid;
4) A chemical precipitation softener, operating at elevated pH (>10);
5) Further cooling;
6) Multi-media filtration;
7) Weak acid cation softeners;
8) Cartridge filtration;
9) A two-pass reverse osmosis system;
10) Neutralization with sulfuric acid, and carbon dioxide (CO_2);

11) Calcium chloride injection, to control sodium adsorption ratio;
12) Post-treatment constructed wetlands; and
13) Percolation through recharge basins.

Treatment of produced water for surface discharge (e.g., Freeport McMoRan's Arroyo Grande field in San Luis Obispo County) is similar to the aquifer recharge scenario described above, but utilizes ceramic membranes to reduce the size of the chemical precipitation softener.

Oil Treatment

When the oil leaves the separator, it is directed to a tank or goes through further separation. Separation may include additional separation time in a knock out vessel or tank, or utilizing a heater treater for the addition of heat, which allows excess water to drop from the oil. Further separation of the oil and the remaining, smaller amount of water is accomplished in a wash tank. Chemicals are usually added to enhance the separation of the oil from the water and increase the efficiency of the system. Typically, saleable oil can be skimmed from the wash tank and moved to a shipping tank. Once the oil meets sale specifications, it is sold and transported primarily by pipeline, but also by truck.

Gas Treatment

Natural gas is usually produced along with the liquid oil and water mixture and separated in the field from the liquids. Some natural gas treatment systems can be extremely simple, such as gas sent from a separation vessel straight to permitted combustion sources, such as flares, generators, or gas disposal wells. If the natural gas is intended for sale to a transportation pipeline, it is typically moved to a central gas treatment plant containing more complex equipment to treat the gas to a desired specification for use or sale to a pipeline system. Separation and compression are typically required. Once the natural gas leaves the separator, it may be compressed to increase the pressure of the gas for treatment. If hydrogen sulfide (H_2S) or other impurities are present, they are removed by scrubbers utilizing a non-hazardous amine system. The natural gas may be further processed at gas plants to remove water and natural gas liquids such as propane, butane and natural gasoline. These natural gas liquids are stored and sold via an adjacent natural gas liquids tanker truck loading facility or sales pipelines. A natural gas liquids loading facility typically consists of tank storage and tanker truck loading racks for delivery to offsite purchasers. Natural gas is delivered to these facilities via pipelines from the gas processing facilities. Processed natural gas is then either transported through sales pipelines to sales metering stations to natural gas purchasers, or may be combusted as fuel for gas-fired equipment, or re-injected in oilfield operations for reservoir pressure maintenance.

Gas gathering, gas sales and gas reinjection systems utilize field compressors and pipelines to transport the natural gas to its intended use. Field gas compression facilities typically consist of an electric or natural gas-fired compressor engines. To the extent practicable, existing systems are used. Staging and installation activities occur on adjacent existing disturbed areas when possible. As gas operations vary over time in the field, relocation of these units is sometimes necessary to optimize gas operations. Natural gas pipelines would be extended along existing ROWs when possible to minimize new disturbances.

In certain instances, the produced gas stream associated with oil production may contain constituents that make it unsuitable for resale or use in onsite facilities. In these instances, the produced gas stream is gathered via small pipelines using a system of vapor recovery units. The gas is then transported via pipeline to a dedicated "waste gas" injection well that disposes of the gas into depleted oil reservoirs. Waste gas injection wells are permitted as Class II injection wells by CalGEM. Among other requirements, the permitting process involves calculating the estimated gas storage volume of the depleted reservoir and evaluating the integrity of any existing wellbores within a quarter-mile of the proposed injection well before the well is authorized. Monitoring requirements for H_2S and limitations on injection pressures are commonly attached to the permit conditions. Quarterly reports are filed with CalGEM that summarize the content of the waste gas stream being injected.

Water Management

Water is required for a variety of purposes related to oil and gas extraction activities, including the following:

- Drilling operations;
- Well stimulation (including hydraulic fracturing);
- Workover activities;
- EOR (such as water and steam flooding);
- Hydrostatic testing (to test pipeline and well integrity);
- Dust suppression (during well pad and access road construction);
- Sanitary purposes (associated with ancillary facilities, including for domestic purposes related to office and field facilities); and
- Reinjection to arrest surface subsidence.

Water required for oil and gas extraction activities, including the production of steam, can come from a variety of sources. Depending on the well's proximity to the water source, water can be transported to the wells via truck and/or pipeline. Common sources include:

- Recycled water from hydrocarbon-bearing formations (produced groundwater), which has been treated as described above;
- Non-potable water from private onsite groundwater wells belonging to the operators;
- Existing surface water entitlements; and
- Public or private water storage districts, which may use water from reservoirs, groundwater, or surface water.

As discussed in Section 4.9, in 2012 the total water demand for oil and gas operations in the Project Area was about 97,590 acre-feet. Produced water was used to meet 88,812 acre-feet, or 91% of the total oil and gas water demand. Other sources, which this SREIR conservatively assumes to consist of water suitable for municipal and industrial purposes, accounted for about 8,778 acre-feet, or 9% total oil and gas water demand in 2012.

Oil producers in the southern San Joaquin Valley currently extract about 12 to 13 barrels (42 gallons) of produced water for every barrel of oil produced. Produced water is non-potable because it is produced as an oil/water mixture from a hydrocarbon-bearing formation, generally contains high salinity, and must undergo treatment before it can be reused for other purposes. The fluid produced from the well dictates the type of production facility required. For wells that produce oil, gas, and water, separation and treatment of these fluids allows the oil and gas to be sold and the water to be disposed of, reused, or re-injected.

Produced Water Reuse for Oil and Gas Activities

As discussed in Section 4.9,of this SREIR and the 2015 FEIR (Volume 3) about 234,949 acre-feet of produced water was generated in the Project Area during 2012. About 38% of the produced water (88,812 acre-feet) was treated in the manner described above in “Water Treatment” and recycled for well completion operations or EOR activities. About 16% of the produced water (38,658 acre-feet) was treated and supplied to the Cawelo Water District in the Eastern Subarea for agricultural reuse. About 48% of the produced water was disposed of into Class II injection wells permitted by CalGEM (84,571 acre-feet) or discharged to surface facilities (30,223 acre-feet). As discussed above, about 91% of oil and gas water demand in the Project Area is met by treating and reusing produced water. In addition to water conservation concerns, operators generally prefer to use produced water as opposed to freshwater in the event that any clays are encountered during drilling. When freshwater contacts clay, the clay swells, effectively blocking any further hydrocarbon production and requiring remedial action to re-stimulate the flow of hydrocarbons. About 9% of the oil and gas water demand, primarily for drilling and steam production activities that require higher-quality water supplies, is met by using municipal and industrial water.

For a description of how water is used in EOR activities, see the Enhanced Oil Recovery Activities section, below. For a description of water use during well stimulation activities, such as hydraulic fracturing, see the Well Stimulation Treatment section, below.

Produced Water Reuse for Agricultural Irrigation

Produced water from certain oil fields in the Eastern Subarea is treated and sold to water districts, such as the Cawelo Water District, which sell the water to agricultural operators for use in crop production. The treated produced water is blended with other supplies and subject to water quality requirements under permits issued by the CVRWQCB. As discussed in Section 4.17, Utilities and Service Systems, of the 2.7 million acre-feet of water used for crop production in Kern County, 32,771 acre-feet (1.2%) in 2012 was derived from produced groundwater that had undergone treatment processes similar to those listed above. Injection wells are described below.

Cogeneration facilities may also use de-mineralized (softened) fresh water for evaporative cooling to increase power output when ambient temperatures are elevated and untreated fresh water for steam condensation, pump seal flushing, and other process uses that require fresh water.

Water Disposal

Water treatment and disposal facilities consist of pipeline gathering systems to collect and transport produced water removed from oil. Excess produced water that is not injected into disposal wells, used for EOR operations or other drilling or well completion activity, may be disposed of in wastewater disposal ponds (also known as percolation or evaporation ponds). These are regulated under WDRs issued by the CVRWQCB. The ponds must be maintained in good condition and in accordance with the conditions and monitoring program established in the WDR. The ponds may require periodic renovation to restore their percolation capabilities by dredging out the ponds bottoms and restoring the original grade of the ponds.

Disposal facilities handle produced groundwater not otherwise utilized and transport water via pipeline to wastewater disposal ponds or to disposal injection wells where the produced water is reinjected into zones, permitted and regulated by the CalGEM underground injection control program. Some of the water sent to disposal wells is also wastewater generated by other oilfield processes, such as brine regeneration in the water softening system.

Enhanced Oil Recovery Activities

EOR is a production technique used to increase the mobility of oil, most commonly through steam injection techniques, which reduce the viscosity of the hydrocarbons and allow produced fluids to flow. EOR operations should not be confused with well completion and well stimulation operations as defined by CalGEM. There are three major types of EOR operations: thermal (i.e., steamflood, cyclic steam and in-situ combustion); CO_2 or other gas (miscible and immiscible); and chemical/polymer flooding (i.e., alkaline flooding or micellar-polymer flooding). While cyclic steam operations have been used in California since the 1950s and steamflood operations since the 1960s, EOR operations have increased since the early 1980s as a result of a 1979 Presidential Order that exempted most heavy crude oil from federal price controls in order to stimulate the nation's declining oil production. EOR facilities typically include the same infrastructure as required for oil and gas production: pipeline distribution, pumps, and compression systems to supply and deliver the material being utilized for EOR to the reservoir, injection wells and observation wells, and production wells, as well as the associated oil, gas and water separation and processing equipment and facilities. Process water for EOR activities is typically composed of treated produced water. Treatment of produced water is described under the Water Management section, above.

CalGEM overseas the state's Underground Injection Control Program, which permits and regulates injection wells for waste disposal and wells for increasing oil recovery through EOR. Wastewater injection wells are described in the Injection Wells section, below.

Thermal

With thermal EOR, steam is injected on either a continuous ("steam-flood") or an intermittent ("cyclic steam") basis. Depending on the geologic properties of the formation being steamed, different types of cyclic steam operations may be designed. The injected steam may also include proprietary chemical additives to enhance the thermal recovery of heavy oil. These differences are explained in further detail below. Steam may be produced via steam generators or cogeneration facilities. Cogeneration facilities are used to produce heat for thermal process use, thermal EOR, and the generation of electric power for use by the oilfield operator, or for sale to other operators.

- **Steam-Flood:** Steam-flooding involves injecting a continuous rate of steam into the reservoir through dedicated wells (steam injectors) to heat up heavier oil to the point it can flow to the wellbore. For production zones using a continuous steam-flood EOR method, injection and observation wells may be placed into the intended reservoir in a specific pattern to sweep the reservoir so as to displace oil and gas to an adjacent ring of producing wells for recovery. These wells can be an existing wellbore converted to an injection or observation well, or new wells can be installed for these purposes, which would be constructed as described above in the Construction Activities section. Once established, the EOR pattern is typically developed outwards in a concentric fashion to sweep a larger portion of the reservoir. Pipeline and infrastructure expansions are conducted to support the EOR from the new portion of the reservoir.

- **Cyclic Steam:** Cyclic steam or intermittent injection of steam into producing wells can be one of three types: (1) maintenance cyclic steam; (2) cyclic steam injected below the reservoir fracture pressure; or (3) cyclic steam injected above the reservoir fracture pressure. Maintenance cyclic steam refers to steam used on an infrequent basis on heavy oil producing wells within a steam-flood where there are dedicated injectors. Steam is injected below formation fracture pressure to clean the wellbore or provide near wellbore heating to allow better reservoir fluid influx from the reservoir to the wellbore through perforated casing or slotted liner.

  Cyclic steam can also be used in areas where the reservoir is cold and there are no dedicated steam injectors. This technique involves alternating steam injection and production in the same wellbore. In this method steam is not continuously injected but, instead, a pre-determined rate of steam is injected into an oil-producing well on an intermittent basis. In these types of operations, the steam typically is applied on a predetermined basis (e.g., every several weeks) or can be applied as determined by the production trends of the individual well. The operation is designed to lower the viscosity of oil and produce the reservoir fluids from the same wellbore. After steaming, the well is shut in for a period of time to allow the steam to condense and transfer heat to the reservoir (referred to as the soak period). After the soak period, which varies per well and formation, the well is opened up, hydrocarbons begin flowing into the well casing, and production continues.

Cyclic steam injected below the reservoir fracture pressure is used where the reservoir has moderate to high permeability to lower the viscosity of the heavy oil. Cyclic steam injected at or above the reservoir fracture pressure is conducted in reservoirs characterized by low permeability to create and improve connectivity in the reservoir, lower the viscosity of oil, and produce the reservoir fluids from the same wellbore. For cyclic steam operations, the depth of the formation and geologic properties of the overlying formations determine whether site-specific mitigation is required to ensure that the injection fluid is confined to the permitted zone or zones of injection. These determinations are made by CalGEM based on the site-specific geologic characteristics.

CalGEM is in the process of developing regulations that will apply to various types of thermal steam production operations. This SREIR is intended to cover all activities that will fall within the scope of the new CalGEM regulations once they have been adopted.

Gas Injection

Gas injection EOR techniques use gases to enhance production. Gases that expand in a reservoir without mixing with the oil are called immiscible gases. Immiscible gases effectively push the reservoir oil toward a producing well, where it is recovered to the surface. In contrast, gases that mix with the oil are called miscible gases. Miscible gases lower the oil's viscosity, thus enabling the oil to flow more easily to the well bore for recovery. Examples of immiscible gases that could be used in these operations include natural gas, nitrogen, or CO_2. Miscible gases include propane, methane enriched with other light hydrocarbons, methane under high pressure, and CO_2 under pressure.

Water Flooding (Water Injection)

Water flooding is the process of injecting water into the reservoir via an injection well for the purposes of "sweeping" the hydrocarbons to a nearby production well, where it can be recovered to the surface.

Chemical Injection

Chemical injection involves the use of long-chained molecules called polymers to increase the effectiveness of water floods or the use of detergent-like surfactants to help lower the surface tension that often prevents oil droplets from moving through a reservoir. Chemical techniques are rarely used in the United States for EOR operations; however, there are three types of chemical injection techniques used in Kern County:

- **Polymer Flooding:** Polymer flooding involves mixing polymers with injection water to increase water viscosity. Increasing the viscosity puts pressure on the reservoir, pushing the oil from the injection well to the producing well.
- **Surfactant Flooding:** Surfactant flooding involves pushing a "soap" through the reservoir to reduce the surface tension of oil droplets. Reducing the surface tension increases the mobility of the oil, stimulating production.

- **Surfactant Polymer Flooding:** Similar to surfactant flooding, except that no alkali is used. It is used in reservoirs where more saline water is present.

Injection Wells

Injection wells used for disposing of produced water are sited in underground formations, such as sandstone, that are porous and permeable enough to accept injected fluids or gas. Rock formations in the zones that are utilized for injection are covered by impermeable formations, such as shale, to isolate the injected liquids from potential migration to other formations.

Injection wells are drilled, cased, and cemented similarly to production wells, or, in some cases, production wells are converted into injection wells. Several tests are then run to make sure the injection well is operating properly and the injected fluids are confined to the intended injection zone. As discussed in Section 4.9, Hydrology and Water Quality, all injection wells must be permitted by CalGEM in accordance with federal requirements under a primacy agreement with the EPA.

Injection wells are used to increase oil recovery and to safely dispose of the water associated with oil and natural gas production and waste gas. Injection wells are classified by the EPA into six classes according to the type of fluid they inject and where the fluid is injected. The Project, for purposes of this SREIR, includes only “Class II injection wells,” which include wells that inject brines and other fluids associated with oil and gas production, or storage of hydrocarbons. Class II well types include salt water disposal wells, enhanced recovery wells, and hydrocarbon storage wells (EPA 2012). As of January 1, 2013, there were more than 42,000 Class II wells in Kern County, including production wells that are temporarily idled for steam or water EOR injection.

All Class II injection wells are regulated by CalGEM, under provisions of the state Public Resources Code and the federal Safe Drinking Water Act (DOGGR 2013d). (Note: The Project does not include hazardous or non-hazardous waste injection wells into the lowermost source of drinking water, or any other regulated category of injection well.)

Injection wells may be located within the wellfield, or fluids may be trucked from treatment tanks onsite to commercial injection facilities located apart from the oilfield operations.

Sumps

As discussed above, a sump is a lined or unlined excavated depression in the ground that collects crude oil, produced water, or solids, such as drilling muds or cuttings, in oil-producing fields. For example, a sump allows oil producers to store oil temporarily if a storage tank needs to be drained and repaired. Sumps are also used in tank overflow situations. In other cases, the sump collects water and allows the water to percolate into the ground in lieu of a disposal well in areas where groundwater is absent or compromised (i.e., where groundwater formations are saline or contain high levels of dissolved solids, making the groundwater non-potable prior to oil and gas development in the area). Sumps are used in combination with other separation and treatment facilities and may be in greater or lesser use depending on the size of the operation. For example, larger operators rely more heavily on aboveground tank systems, while smaller operators rely more heavily on sumps due to the dispersed nature of production. The following types of operational sumps typically have been associated with oil and gas production in Kern County:

- **First Stage Production Sump:** A sump that receives a stream of crude oil and produced water directly from an oil production well(s) or a field gathering system(s). This type of sump is no longer in service. First stage fluid production is sent to tanks.
- **Second Stage Sump:** A sump that receives produced water from one or more upstream first stage separation processes, including sumps, free water knockout vessels, wash tanks, etc.
- **Third Stage Sump:** A sump that receives produced water from one or more upstream second stage sumps, or subsequent separation processes.

The State Water Resources Control Board has issued general WDRs for discharges to land with a low threat to water quality (Water Quality Order No. 2003-0003-DWQ), which cover evaporation and percolation ponds for the following:

- Wells/Boring Waste, Well Development Discharge, Monitoring Well Purge Water Discharge, Boring Waste Discharge;
- Clear Water Discharges, Water Main/Water Storage Tank/Water Hydrant Flushing, Pipelines/Tank Hydrostatic Testing Discharge, Commercial and Public Swimming Pools;
- Small/Temporary Dewatering Projects (such as excavations during construction); and
- Miscellaneous, Small Inert Solid Waste Disposal Operations and Cooling Discharge.

Percolation and Evaporation Ponds

Similar to a sump, a percolation pond acts as a holding facility while gravity allows the water to percolate or seep through the soils. A percolation pond is used to dispose of water associated with hydrocarbon production. A natural or artificial evaporation pond is a pond with a large surface area that is designed to efficiently evaporate water by exposure to sunlight. Percolation and evaporation ponds vary in size but are typically between 2 and 5 acres and can be as shallow as 5 feet deep. Some facilities contain multiple ponds totaling as much as 80 acres. The CVRWQCB adopts site-specific WDRs for percolation and evaporation ponds.

Vegetation Control

Vegetation along roadsides and critical facilities such as tank settings and compressor stations is controlled as needed through the use of mowing, grading, weed-whacking, and spot treatments of herbicides. If vegetation removal would occur in potential habitat for special-status species, approval by the USFWS and CDFW may be required. This activity typically occurs in previously disturbed sites. Application of herbicides to prevent re-growth of vegetation in and around facilities is limited and only certified applicators and licensed firms are used.

Spill Prevention, Control, and Countermeasure Procedures

AB 1960, passed in 2008, required CalGEM to prescribe, by regulation, standards for oil and natural gas production facilities. These regulations were developed to ensure that industry operations remain protective of the environment and reduce the risk associated with leaks and spills through a comprehensive regulatory program, and address the following areas:

- Life of well/life of facility bonding requirements;
- Facility maintenance standards including:
  - Requirements for secondary containment around permanent facilities,
  - Maintenance, testing, and leak detection standards for tanks and tank bottoms,
  - Pipeline installation and testing standards,
  - Requirements for idle and out-of-service facilities;
- Spill Contingency Plan; and
- Inspection and document retention requirements.

In addition, in accordance with EPA SPCC rule (40 CFR part 112), facilities storing, processing, refining, using, or consuming oils must prevent a discharge of oil into navigable waters or adjoining shorelines. Facilities that qualify under this rule must prepare and implement an SPCC Plan. Although each SPCC Plan is unique to the facility, there are certain elements that must be described in every SPCC Plan, including the following:

Prevention Measures: Steps that a facility owner/operator can take to prevent oil spills could include:

- Using containers designed for the oil stored;
- Providing overfill prevention for oil storage containers (e.g., a high-level alarm or audible vent);
- Periodically inspecting and testing pipes and containers. Visually inspecting aboveground pipes and oil containers according to industry standards; leak testing buried pipes when they are installed or repaired, and including a written record of inspections;
- Implementing security measures to prevent acts of vandalism, including locks, motion activated lights, and enclosed storage; and
- Providing annual trainings and briefings regarding revisions to the SPCC Plan for trained personnel.

Control Measures: Steps that a facility owner/operator can take to control oil spills could include:

- Providing sized secondary containment for bulk storage containers, such as a dike or a remote impoundment. The containment needs to hold the full capacity of the container plus possible rainfall. The dike may be constructed of earth or concrete;
- Providing general secondary containment to catch the most likely oil spill where oil is transferred to and from containers and for mobile refuelers and tanker trucks (e.g., sorbent materials, drip pans, or curbing for these areas); and
- Detailing response measures, including shutting down pumps or equipment, identifying and securing sources of the discharge and containing the discharge with sorbents, sandbags, or other material from the spill kits, if safe to do so.

Countermeasures: Steps that a facility owner/operator can take to clean and mitigate oil spills could include:

- Identifying the reporting requirements of regulatory authorities and other response personnel and organizations after the discovery of a discharge (including CalGEM's San Joaquin Valley Oil Spill Reporting Criteria; AB 1376). The reporting requirement should detail the reportable quantity requirements for each contact, contact information, and a list of information to be provided to the contacts regarding the discharge;
- Identifying contaminated soil through visual and olfactory senses and soil sampling (testing);
- Monitoring air quality during excavation of contaminated soil;
- Collecting water from decontamination procedures and treating or disposing of it at an appropriate disposal site;
- Identifying appropriate transportation and disposal facilities, procuring all necessary permits and pay necessary fees for the transport and disposal of contaminated soils;
- Excavating contaminated soil; if temporary stockpiling of contaminated soil is necessary, implementing control measures to prevent discharge; and
- Defining discharges that can be remediated by onsite personnel (e.g., managed with shovels) and discharges that required assistance from a cleanup contractor (e.g., mobilization of heavy equipment, construction of berms, and excavation of contaminated soils).

In compliance with EPA SPCC requirements and CalGEM facility regulations, secondary containment structures are required to be constructed around tanks, chemical containers, etc., to ensure that oil or chemicals are not discharged into natural drainage ditches and the environment. Corrugated pipe filled with concrete, concrete berms, and earthen berms are typically used and are designed and constructed to contain a minimum of 110% of the volume of the largest tank that is located within the facility. Periodic inspections of secondary containment berms would be conducted to ensure that the integrity has not been compromised, and maintenance work is conducted as necessary.

Oil spill prevention and cleanup measures are required at bulk storage tanks, facility transfer operations, loading and unloading racks, production facilities, and oil drilling facilities. Mechanical containment, chemical and biological methods, and physical methods are used. Some spills can require minimal efforts to remediate (i.e., managed with shovels); however, larger spills may require mobilization of heavy equipment, construction of berms, and excavation of contaminated soils. All of the related oil spill prevention measures and the cleanup plans must be in accordance with EPA and CalGEM regulations.

Releases from unplanned events, such as power outages, wildfires, extreme weather, etc., equipment failures, and emergencies have the potential for impacting the environment during and after the response to the release. In addition, unknown contaminated sites, either related or not related to oil and gas activities, could be discovered that would require investigation, characterization, and remedial action. Remedial activities normally involve site sampling to characterize the magnitude and extent of the contamination. Risk-based corrective measures are then developed, and contaminants such as hydrocarbons or other chemicals above action levels would be excavated, removed from the site, and properly disposed of. Environmental restoration could also be required at some locations that were heavily impacted.

Non-Hazardous Solid Waste Management

During production, a number of waste management activities are conducted, depending on the type of waste. The oil industry typically divides oil development non-hazardous solid wastes into two categories: (1) drilling and other wastes associated with exploration and production; and (2) other wastes.

Drilling and Other Associated Wastes

Drilling wastes include drilling muds, drill cuttings, wash water, and other related wastes. The actual amount differs based on the depth of the well. EPA regulations exempt drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil and natural gas (oilfield wastes) from hazardous waste requirements under the Resource Conservation and Recovery Act (RCRA). California regulations exempt oilfield wastes from designation as a California non-RCRA hazardous waste based on toxicity characteristics. However, California did not adopt state regulations that provide exemptions similar in scope to the federal RCRA exemption and does not offer a blanket exemption from state hazardous waste requirements. Oilfield wastes in California may be considered hazardous waste as defined by the State and potentially subject to regulation, depending on how they are managed. The generator of the waste has an obligation to properly characterize the waste, either based on generator knowledge of the waste stream or waste-generator process, or by testing representative samples of the waste.

Oilfield-related wastes that exhibit hazardous waste characteristics or that are listed hazardous wastes (e.g., spent solvents), and that are not otherwise excluded or exempt, are typically sent offsite for disposal at facilities authorized by the DTSC or are sent out of state for disposal.

However, most drilling and production wastes, including oily dirt from spill cleanup operations and produced water, are nonhazardous and, thus, not subject to regulation by the DTSC. Allowable methods for managing these wastes include the following:

- Underground injection such as in disposal wells;
- Onsite burial such as in pits, and landfills;
- Land treatment such as by land spreading, land farming, and road spreading;
- Evaporation;
- Discharge to percolation ponds;
- Offsite disposal; or
- Recycling.

Other Waste

Other types of waste generated in the course of oilfield operations include wood, metal equipment parts, damaged tools, construction debris, excess soil and vegetation generated from cutting and grading, wood, concrete residue, pallets, cardboard boxes, papers, plastics, banding materials, scrap steel, scrap aluminum, scrap wire, and general trash. These wastes are collected at specially permitted in-field solid waste transfer stations or disposed of in onsite permitted facilities, or transported to offsite landfills or recycling facilities as appropriate on a regular basis. Transfer stations consist of containers where waste is collected for transfer to Kern County landfills or other approved sites. It is estimated that 11 cubic feet of road mix would be generated per well. Excess soil and vegetation (mulched) found to be nonhazardous could be used as ground cover.

Land farms accept biodegradable non-hazardous oily materials and are permitted by the CVRWQCB. Daily operations at permitted land farms in the Project Area include, but are not limited to, the discharge, spreading and discing of the biodegradable non-hazardous oily wastes. Other activities within or adjacent to the pre-disturbed land farms area might include: (1) vacuum truck washouts and sumps; (2) portable tank staging; and (3) drainage control grading maintenance.

Well, Pipeline, Tank and Vessel Testing and Maintenance

Well Mechanical Integrity and Standard Annular Pressure Testing

If a well has been idle for several years, prior to resuming production, CalGEM requires that the well be tested to determine the integrity of the well casings and to ensure that casings effectively isolate the well from the surrounding formations. A pressure test is conducted using a fluid to fill the annular space between the casing, tubing, and packer. Pressure is maintained for a specified period of time at a specified pressure. If the closed system retains pressure after the pressure source is removed, the well is determined to have mechanical integrity. Loss of test pressure during the procedure indicates a lack of mechanical integrity in which case downhole components are leaking and require corrective action prior to returning the well to service. The tests are conducted by well servicing equipment that is restricted to the existing well pad.

Pipeline, Tank and Vessel Testing and Maintenance

Pipelines, tanks, and vessels are hydrostatically tested to meet regulatory pressure requirements. To conduct a hydrostatic test, a section of a pipeline is filled with fresh water, and the pressure is increased to determine whether there are any leaks. If pressure is lost during the test, then the pipeline is repaired before being put back into service. The hydrostatic test water can be stored in tanks, released in sumps, or collected for transport to existing wastewater disposal facilities. Fluid disposal complies with the requirements of the CVRWQCB.

Other types of non-destructive testing include radiography, ultrasonic testing, and electromagnetic testing. These methods monitor thickness of pipe walls or coatings, identify cracks in joints, welds or pipeline components, or detect other defects and anomalies. Areas of potential weakness caused by corrosion, erosion, or stress are then identified so that corrective action can be taken.

Pipeline maintenance also includes pigging, which is a method of using a mechanical device called a “pig” to scour the inside of a pipeline. Pigging helps keep the line clean and protects it from erosion. Pigs are introduced into a section of pipeline to be cleaned or tested at a “pig launcher” facility and removed from the pipeline at a “pig receiver” facility. These launching and receiving facilities typically have secondary containment structures such as lined or concrete pits to contain liquids generated from the cleaning and testing. “Smart pigs” containing electronic instruments are used to conduct surveillance and testing of pipelines.

Steam Generators

As described above, steam generators are used to generate steam for thermal enhanced oil recovery. Steam generators are large heaters that generate steam, usually from produced groundwater. These generators are typically powered by electricity or natural gas. A thermal generator and water storage tank may be installed at an individual injection site or built in a centralized location to reach multi-injection sites. Aboveground pipelines would connect the thermal generator and water storage site to the injection sites. Generators may be co-located with other equipment (e.g., separation tanks), etc.

Electric Distribution Line and Substation Maintenance

Electrical distribution networks and substations require periodic maintenance, repairs, and upgrades. For electrical distribution lines, this work requires a bucket truck and pick-up trucks that drive to individual pole locations. These activities utilize existing roads and occasional cross country travel. No new roads are created for these activities. Substation repairs and upgrades are infrequent. These activities involve replacement or upgrades of switches, transformers, and conductors within the footprint of the substation. Due to the size of some of the equipment, delivery could be required by semi-truck. Cranes, bucket trucks, and crew pick-ups trucks are typically used in these activities, as well.

Access Road Maintenance

Both the roadbed and shoulder areas may be maintained to provide a smooth surface and adequate drainage. Repairs will occur, as needed, to correct normal wear and tear or storm damage such as culvert repairs and replacements

Distribution of Crude Oil

Crude oil produced in Kern County is shipped to offsite storage facilities or refineries to be processed into gasoline and other products via distribution pipelines, and/or tanker trucks. Railcars are not used for crude oil transportation of crude produced in Kern County. There are 22 refineries and about 52 related storage distribution facilities operating in California (CEC 2008); only three refineries and 23 storage distribution facilities are located within the Bakersfield area of Kern County (CEC 2012). However, no improvements, expansions, or modifications to existing refineries or storage distribution facilities in Kern County are anticipated as part of the proposed Project.

Transmission Pipelines

Transmission pipelines are used to transport produced crude oil to refineries or to offsite storage facilities. The vast majority of crude oil produced in Kern County is transported via transmission pipelines (95% to 98%). Produced crude oil is pumped into each oil production operation's onsite storage facility. All three refineries and storage transmission facilities operating in Kern County are connected to the existing produced crude oil distribution pipeline network.

Newly constructed transmission pipelines (e.g., from new wells) are generally connected to the existing network of transmission pipelines that already serve established wellfields, rather than directly to the intended destination.

Transmission pipelines can range in size from 6 to 42 inches in diameter and are typically located underground. Twenty-inch transmission pipelines can move crude oil at a rate of about 4,000 barrels per/hour. Due to the viscosity and inertia of the crude oil, some transmission pipelines systems require external heating. Booster stations are placed at intervals on the line where heating and or pumping units facilitate the flow of the crude oil through the line (CEC 2006).

Distribution pipelines are regulated by the State Fire Marshal's office pursuant to California Government Code Section 51010 et seq. The State Fire Marshal ensures that all intrastate non-gravity-fed (or at a stress level above 20%) pipelines transporting crude oil meet the requirements of the Hazardous Liquid Pipeline Safety Act (49 United States Code Sec. 2001 et seq.) and federal pipeline safety regulations, as necessary to obtain annual federal certification. The construction of distribution pipelines requires several approvals by federal, state, and local agencies, depending on the location, in addition to certification and decisions on state and federal environmental documents.

Tanker Trucks

Crude oil is also distributed to refineries or to offsite storage facilities using tanker trucks. Between 2% and 5% of crude oil produced in Kern County is transported via tanker trucks to central facilities. At times the trucks carry crude oil to local refineries; at other times trucks carry crude oil to a facility where it is placed into a pipeline system. In either case, crude oil would be loaded into tanker trucks directly from the operation's onsite storage facility. All three refineries and related storage distribution facilities in Kern County are equipped to accept oil from tanker trucks. The crude oil delivered to storage distribution facilities would later be pumped into a distribution pipeline or tanker trucks to transport the crude oil to offsite locations.

A typical tanker truck is able to transport 9,000 gallons of crude oil. The transportation of crude oil via tanker truck is regulated by Caltrans and U.S. USDOT motor carrier regulations.

Administrative Building and Personnel Housing

As described in the Construction Activities section, above, some staffed administrative offices are located in wellfields, particularly in more established Tier 1 areas. Administrative offices typically range from 1,000 to 10,000 square feet, depending on the size of the development and number of day-to-day personnel. In addition to office space, an administrative office in an oilfield could include control and monitoring equipment, material storage, equipment warehouse, restrooms, and a kitchen. Personnel would be present in the administrative office during business hours, generally from 6:30 a.m. to 4:30 p.m., five days a week.

Sanitary wastewater for administrative offices in communities such as Bakersfield are managed through the municipal wastewater treatment systems, and for offices in oilfields wastewater is managed with septic systems. Existing septic systems are maintained by pumping on a regular schedule by approved septic pumper subcontractors. The wastes are hauled offsite to an approved disposal site. Repairs to existing septic systems or installation of new systems require a building permit from the Kern County Building Department. Septic systems must comply with the Uniform Plumbing Code unless the system size/soil conditions require an engineered septic system. Engineered septic systems are designed by a civil engineer and plans are submitted to the Kern County Public Works Department for approval.

Oilfield personnel may also utilize mobile housing facilities. These facilities provide up to 50 spaces for recreational vehicles or travel trailers to house onsite oilfield personnel on a rotating basis. Such facilities provide living quarters for personnel of the oil company owning the property and are accessory and incidental to existing oilfield operations. Additional recreational vehicles/travel trailers travel with drilling rigs and are used as living quarters for drill crew members.

3.5.4 Truck Trips

A description of round trips associated with the Project is provided in Section 4.16, Transportation and Traffic. The Applicant's Traffic Study (see Appendix W of the 2015 FEIR, provided in Volume 4 of this SREIR) includes more details regarding vehicle trips. For purposes of this SREIR, truck trips include both construction vehicles and the light-duty pick-up trucks and automobiles used most frequently by staff servicing oilfield equipment.

3.5.5 Best Management Practices

The following best management practices (BMPs) were submitted by the Project Proponent on October 30, 2013. These BMPs were considered in preparing this SREIR, and in many instances are already required by applicable law and regulations. For purposes of analyzing the potential significance of an environmental impact, the EIR does not assume that any of these BMPs will be implemented. Many of these BMPs (or measures that are similar to or more protective than these BMPs) have been included in this SREIR as mitigation measures, which are enforceable obligations of the Applicants and are included in the Mitigation Monitoring and Reporting Program.

Operational Provisions

1. All drilling installations and operations shall comply with the requirements of state law and with applicable fire and safety ordinances and regulations of Kern County.
2. Proven technological improvements generally accepted and used in drilling and production methods shall be employed as they may become available if they are capable of reducing nuisances or annoyances.
3. All derricks, boilers, and other drilling equipment employed pursuant to this section to drill any well hole or to repair, clean out, deepen, or redrill any completed or drilling well shall be removed within 90 days after completion of production tests following completion of such drilling, or after abandonment of any well, unless such derricks, boilers, and drilling equipment are to be used within a reasonable time, as determined by the Planning Director, for the drilling of another well or wells on the premises.
4. Any derrick used for servicing operations shall be of the portable type, provided, however, that upon presentation of proof that the well is of such depth or has such other characteristics, or for other cause, that a portable type derrick will not properly service such well, the Planning Director may approve the use of a standard type of derrick.
5. Whenever a well is located within 500 feet from an existing dwelling unit, except in the event of an emergency, no materials, equipment, tools, or pipe used for either drilling or production operations shall be delivered to or removed from the drilling site, except between the hours of 8:00 a.m. and 8:00 p.m., unless otherwise required by CalGEM to protect the integrity of the well bore or to protect public health, safety, and the environment.

Compliance with Other Regulatory Agency Requirements

1. All applicable federal, state, and County rules and regulations shall be complied with at all times, including, but not limited to, the rules and regulations of the following agencies:
   – California Geological Energy Management Department;
   – Kern County Fire Department;
   – Kern County Public Health Services Department;
   – USFWS;
   – CDFW;
   – DTSC;
   – CVRWQCB;
   – SJVAPCD; and
   – Kern County Public Works Department.

Land Use

1. Drilling shall not be commenced within 100 feet of any existing residence without the written consent of the owner of such structure.
2. No oil or gas well shall be drilled within 100 feet of any public highway or building not necessary to the operation of the well (or within 150 feet of any dwelling,), or within 300 feet of any building used as a place of public assembly, institution, or school, or within 50 feet of any building utilized for commercial purposes constructed prior to the commencement of such drilling, without the written consent of the owner of such structure. This provision does not apply to administrative and other buildings that are ancillary to oil and gas operations.
3. Whenever oil or gas is produced into and shipped from tanks located on the premises, such tanks, whenever located within 500 feet of any dwelling or commercial building, shall be surrounded by shrubs or trees, planted and maintained so as to develop attractive landscaping, or shall be fenced in such a manner as to, insofar as practicable, screen such tanks from public view. Such fencing shall comply with the requirements of CalGEM.

Agricultural Resources

1. When the applicant/operator is conducting operations on land that has surface co-users, it shall engage the other user(s) and ensure that principles/guidelines are established for work in the area (gate closures, potential crop damage and subsequent management, safety of workers in the area, etc.).
2. Fugitive dust emissions from un-surfaced access roads and construction sites shall be managed as per SJVAPCD regulations or as needed to ensure worker/receptor safety.

Biological Resources

1. Within 14 days before any ground disturbance activities on previously undisturbed property, a qualified biologist shall conduct a focused survey to determine the presence/absence of sensitive species protected by state and federal Endangered Species Acts and potential impacts to sensitive species onsite. The survey shall be conducted in accordance with the standard protocol of USFWS and CDFW.
2. If take of covered endangered or threatened species has the potential to occur, the appropriate USFWS and CDFW Endangered Species Act permits will be acquired and compliance provisions shall be followed.
3. The operator shall, by appropriate design, maintain ground openings in order to protect wildlife from becoming entrapped within them. Leakage from facilities which may impact wildlife shall be minimized.
4. If the operator or its employees, contractors, or agents kills or injures a state or federally listed species, or finds any such animal dead, injured, or entrapped, the operator shall notify the CDFW and USFWS immediately. The operator shall also contact the local CDFW warden. A qualified biologist shall document all circumstances of death, injury, or entrapment of state or federally listed species. The biologist shall: (1) take all reasonable steps to enable the individual animal to escape, if it is entrapped; (2) contact the CDFW or other appropriate authorities to identify an approved rehabilitation center and appropriate capture and transport techniques, if the animal is injured; and (3) if the animal is dead, document the circumstances of death in writing and photograph the dead animal in situ.
5. All vehicles shall observe a speed limit of 25 miles per hour or less on non-public roads during construction, operation, and maintenance activities. When necessary, a lower speed limit may be implemented.
6. All pipe 3 inches or greater in diameter stored overnight on a location must have end caps that prevent wildlife from entering the pipe.
7. All food-related trash such as wrappers, cans, bottles, and food scraps shall be disposed of in closed containers only, and regularly removed from the Project site. Feeding of wildlife is prohibited.
8. An educational briefing shall be conducted for all Project personnel on previously undisturbed property prior to the start of the covered Project/activity. The briefing shall include a discussion of all sensitive species that may be encountered in the Project Area, the laws and codes that affect protected species, and the protection measures that must be followed to avoid and minimize impacts.
9. The applicant/operator shall consult with the CDFW as necessary to determine if a Section 1602 Lake or Streambed Alteration Agreement will be required for Project implementation.
10. Prior to construction in any potential wetland drainage feature, a wetland delineation report shall be prepared by a qualified consultant and any recommendations implemented.

Soils and Geological Resources

1. Design runoff control features related to oilfield structures and activities to minimize soil erosion.
2. Minimize ground disturbance and control erosion by avoiding steep slopes and by minimizing the amount of surface disturbance needed for roads, well pads, pipelines, and electrical lines. Keep equipment and vehicles within the limits of the initially disturbed areas to the extent possible.

Water Resources

1. Avoid streams, wetlands, and drainages, where possible. Locate access roads to minimize stream crossings and to minimize impacts where crossings cannot be avoided. Obtain from the CDFW a Lake or Streambed Alteration Agreement prior to any work in a state jurisdictional waterway, unless the CDFW determines that a Lake of Streambed Alteration Agreement is not necessary, and informs the applicant of such determination in writing, or otherwise fails to issue such agreement within mandated time lines.
2. The applicant/operator shall obtain coverage under and comply with the terms of the appropriate storm water permit and shall develop a storm water management plan to ensure compliance with state regulations and prevent offsite migration of contaminated storm water or increased soil erosion.

Flooding

1. Well pads should be developed outside 100-year floodplains, where possible.

Fire Safety

1. Drilling and production activities shall conform to all applicable fire and safety regulations, and firefighting apparatus and supplies required by the Kern County Fire Department shall be maintained onsite at all times during drilling and production operations.
2. The applicant/operator shall minimize human-caused wildfires by carrying water or fire extinguishers and shovels in non-passenger vehicles in the field. The use of shields, protective mats, and other fire prevention methods shall be used during grinding and welding to minimize the potential for fire. Personnel shall be trained regarding potential fire hazards and their prevention.

Odor Management

1. When adjacent to residential uses, the operator shall undertake an odor minimization measure to reduce or eliminate odors from oilfield equipment, including wells and drilling operations.

Noise

1. Operate pumping wells by electric motors or muffled internal combustion engines.

2. Locate all stationary construction equipment (i.e., compressors and generators) and exploratory and production wells as far as practicable from nearby residences and other sensitive receptors. If drilling equipment will be placed near residences or other sensitive receptors, sound walls should be installed during drilling activities.
3. Route heavy truck traffic supporting construction and drilling activities away from adjacent residences and other sensitive receptors.

Aesthetics/Visual

1. The height of all pumping units shall not exceed 60 feet measured from the base of the pumping unit, unless required to lift reservoir fluids, and shall be painted and kept in neat condition.

Health Safety

1. Sanitary toilet and washing facilities, if required by the Kern County Environmental Health Services or other governmental agencies, shall be installed and maintained in a clean and sanitary condition during drilling operations, and at such other times as specified by these agencies.

Public Safety

1. After production begins and a pump is installed on the wellhead, a fence at least 6 feet in height shall be installed around the pump site or drilling island for public safety. This fence shall be constructed of chain link with wood or metal slats or other screening fence as may be approved by the Planning Director. This fencing and screening requirement shall apply only to those pump sites located within 500 feet of any dwelling. Such fencing shall comply with the requirements of CalGEM.

Air Quality

1. Development and operation of stationary source facilities shall comply with all SJVAPCD rules and regulations.
2. Fugitive dust emissions from un-surfaced access roads, maneuvering (turn-arounds), parking areas, and construction sites shall be managed as per SJVAPCD regulations, or as needed to ensure worker/receptor safety.
3. Minimize the amount of well site disturbance and areas cleared of vegetation.
4. Use dust abatement techniques, in accordance with SJVAPCD regulations, on unpaved surfaces where adjacent to residential use to minimize airborne dust during earthmoving activities.
5. Post and enforce speed limits to reduce airborne fugitive dust caused by vehicular traffic.

Cultural and Paleontological Resources

1. During all phases of the Project, keep equipment and vehicles within the limits of the disturbed well site areas as much as possible.

2. Should cultural, archaeological, or paleontological resources be identified on the Project site during any ground-disturbing activities related to the Project, ground-disturbing activities proximate to the Project shall cease. The operator shall notify and retain a qualified archaeologist or paleontologist to provide an evaluation of the find in conformance with CEQA Guidelines Section 15064.5.
3. If human remains are found during construction, further work or disturbance of the site will be halted. The discovery will be inspected and the remains handled in a manner consistent with California Public Resources Code Section 5097.98-99, Health and Safety Code 7050.5, and CEQA Section 15064.5.

Lighting

1. The applicant/operator shall ensure that any exterior night lighting installed within 500 feet of residences utilize low intensity, low glare design, minimum height, and be hooded to direct light downwards.

Spill Prevention and Remediation Measures

1. Oil and chemical spills shall be cleaned up in accordance with the EPA SPCC Plan for the site to protect personnel, wildlife, and habitat—provided, however, that nothing herein contained shall be construed to alter the operator's obligations under existing laws and regulations. When a spill occurs, emergency actions to stop the spill or leak as soon as possible and ensure the safety of personnel shall be taken.

Oilfield Waste Management

1. Oilfield waste (hazardous and non-hazardous) shall be managed as required by rules and regulations and shall be properly disposed of at an appropriate facility.

Signage

1. Signs shall be limited to directional, warning, and identification in connection with oil, gas, or other hydrocarbon drilling and development operations.
2. No signs, other than directional and warning signs and those required for identification of the well, shall be constructed, erected, maintained, or placed on the premises or any part thereof, except those required by law or ordinance to be displayed in connection with the drilling or maintenance of the well.

Abandonment/Reclamation

1. Within 60 days after any well has been placed in production, or after its abandonment, earthen sumps used in drilling or production or both (unless such sumps are to be used within a reasonable time as determined by the Planning Director for the drilling of another well or wells) shall be filled and the drilling site restored as nearly as practicable to a uniform grade. Temporary earthen sumps may be used for cleanout or remedial work on an existing well or other production facility. However, these sumps shall be filled and the site restored as nearly

as practicable to uniform grade within 60 days after the cleanout or other remedial work is completed. Such restoration work shall comply with all applicable regulations of CalGEM. Centralized drilling sumps serving multiple drilling locations are allowed provided: (1) the existence of the centralized facility reduces the number of sumps used by the operator; (2) the sump remains in active use and has not been idle for more than 60 days; (3) appropriate steps have been taken to screen the sump for protection of wildlife; and (4) the sump is maintained and operated in accordance with all applicable rules and regulations of CalGEM and the Central Valley RWQCB (CVRWQCB).

2. Reclamation and re-vegetation of abandoned or disturbed areas no longer needed for oil and gas activities shall be implemented to minimize erosion and reduce air pollution from disturbed areas. Re-vegetation shall be conducted in accordance with native vegetation in the immediate area.

3.6 Project Objectives

3.6.1 County Objectives

The County has defined the following objectives for the Project:

- Update the County's Zoning Ordinance to create a local permit for oil and gas activities so that County development standards and protective mitigation measures for the purpose of reducing or eliminating potential significant adverse environmental impacts, to the extent feasible, of future oil and gas activities, thereby, ensuring that current County ordinances implement the Board of Supervisor's policies to protect the health, safety, and general welfare of communities, residents, and visitors.
- Encourage ongoing economic development by the oil and gas industry that creates quality, high paying jobs and promotes capital investment in Kern County, which enables the County to invest in capital improvement projects and social programs, which benefit County residents, retail businesses, and capital industries, thus ensuring the County's fiscal stability.
- Continue Kern County's ongoing commitment to consult and cooperate with federal, state, regional, and local agencies by periodically reviewing adopted regulations to ensure the long-term viability of Kern County's resources.
- Continue to improve and streamline current energy regulations and increase County monitoring and involvement in state and federal energy legislation.
- Protect areas of important mineral, petroleum, and agricultural resource potential for future use by promoting sustainability and encouraging BMPs, which are mutually beneficial, through strategic short- and long-range planning.

- Ensure the protection of environmental resources by emphasizing the conservation of productive agricultural lands, the encouragement of planned urban growth, the promotion of clean air strategies to address existing air quality issues, and the promotion of long-term water conservation strategies that will ensure the quality and adequacy of surface and groundwater supplies for future growth of all of Kern County's industries.
- Contain new development within an area large enough to meet generous projections of foreseeable need but in locations that will not impair the economic strength derived from residential developments, agriculture, rangeland, mineral resources, or diminish the other amenities that exist in Kern County.

3.6.2 Applicant Objectives

The Project Proponents have defined the following objectives for the Project:

- Create an effective regulatory and permitting process for oil and gas exploration and production that can be relied on by the County, as well as CalGEM and other responsible agencies.
- Achieve an efficient and streamlined environmental review and permitting process for all oil and gas operations covered by the proposed Project.
- Provide for economically feasible and environmentally responsible growth of the Kern County oil and gas industry.
- Develop industry-wide best practices, performance standards, and mitigation measures that ensure adequate protection of public health and safety and the environment.
- Increase oil and gas exploration and production in Kern County as a means of reducing California's dependence on foreign sources of energy.
- Increase oil and gas exploration and production in Kern County as a means of increasing employment opportunities and economic prosperity for Kern County's residents, businesses, and local government.

3.7 Cumulative Projects

CEQA requires that an EIR evaluate a project's cumulative impacts. Cumulative impacts are the project's impacts combined with the impacts of other related past, present, and reasonably foreseeable future projects. As set forth in the CEQA Guidelines, the discussion of cumulative impacts must reflect the severity of the impacts, as well as the likelihood of their occurrence; however, the discussion need not be as detailed as the discussion of environmental impacts attributable to the project alone. As stated in CEQA, Public Resources Code, Section 21083(b) (2), "a project may have a significant effect on the environment if the possible effects of a project are individually limited but cumulatively considerable."

According to Section 15355 of CEQA Guidelines:

Cumulative impacts refer to two or more individual effects, which, when considered together, are considerable and which compound or increase other environmental impacts.

(a) The individual effects may be changes resulting from a single project or a number of separate projects.

(b) The cumulative impact from several projects is the change in the environment that results from the incremental impact of a project when added to other closely related past, present, and reasonable foreseeable probable future projects. Cumulative impacts can result from individually minor but collectively significant projects taking place over a period of time (CCR, Title 14, Division 6, Chapter 3, §15355).

In addition, as stated in the CEQA Guidelines, it should be noted that:

> The mere existence of significant cumulative impacts caused by other projects alone shall not constitute substantial evidence that the proposed project's incremental effects are cumulatively considerable (CCR, Title 14, Division 6, Chapter 3, Section 15064[h][4]). "Cumulatively considerable" means that the incremental effects of an individual projects are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects.

Cumulative impact discussions for each environmental topic area are provided at the end of each technical analysis contained within Chapter 4 of this SREIR, under "Impacts and Mitigation Measures." As previously stated, and as set forth in the CEQA Guidelines, related projects consist of "closely related past, present, and reasonable foreseeable probable future projects that would likely result in similar impacts and are located in the same geographic area" (CCR, Title 14, Division 6, Chapter 3, Section 15355).

An adequate discussion of significant cumulative impacts must include either a list of past, present, and probable future projects producing related or cumulative effects, or a summary of projections from an adopted local, regional, or statewide plan, related planning document, or related environmental document that describes conditions contributing to the cumulative effect (CEQA Guidelines Section 15130(b)(1)). This cumulative analysis uses the plan/projection approach, and includes both the KCGP and the regional growth plan and projections included in the Kern County Council of Governments Regional Transportation Plan/Sustainable Communities Strategy, (RTP/SCS) approved in 2014.

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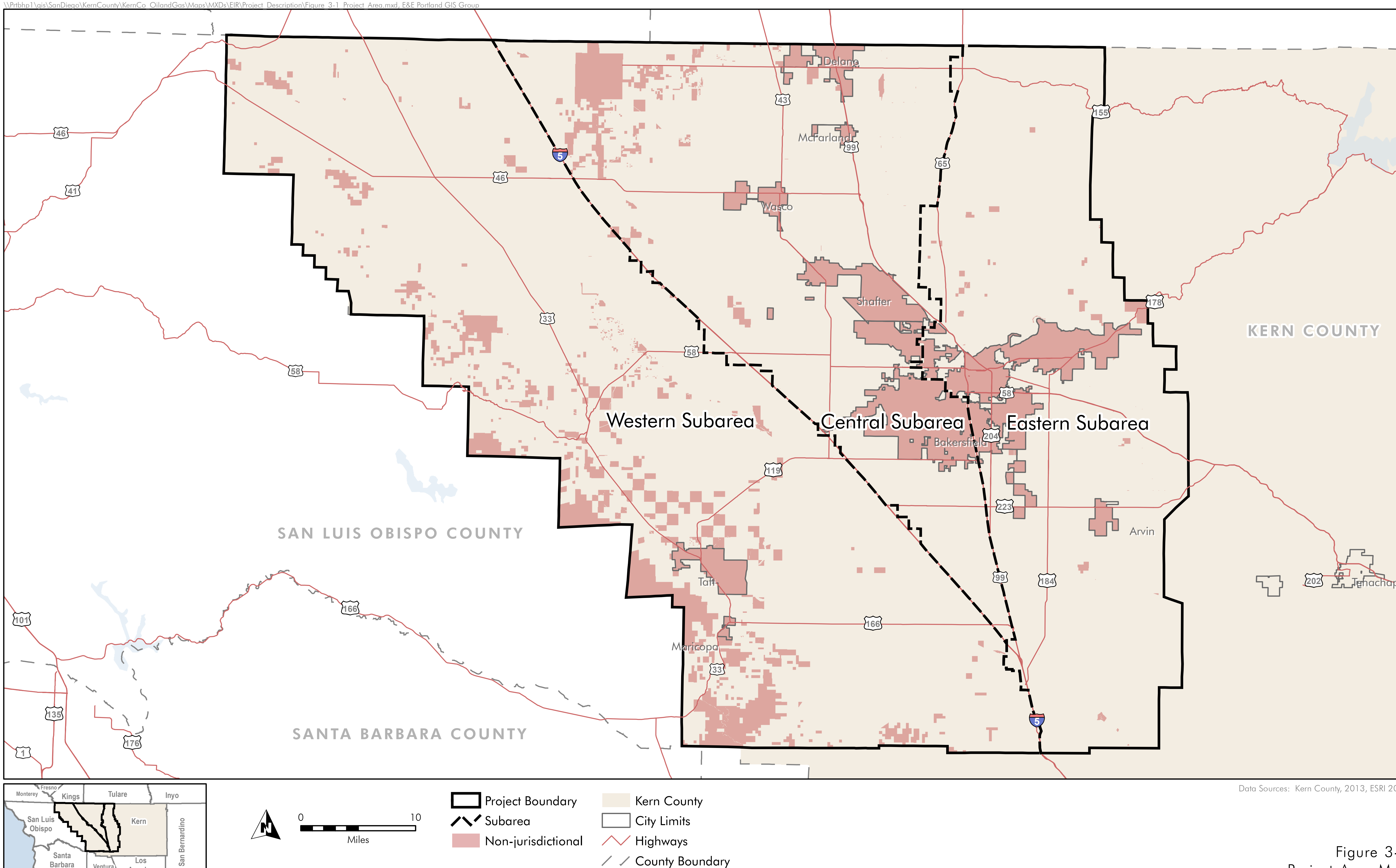

Figure 3-1
Project Area Map

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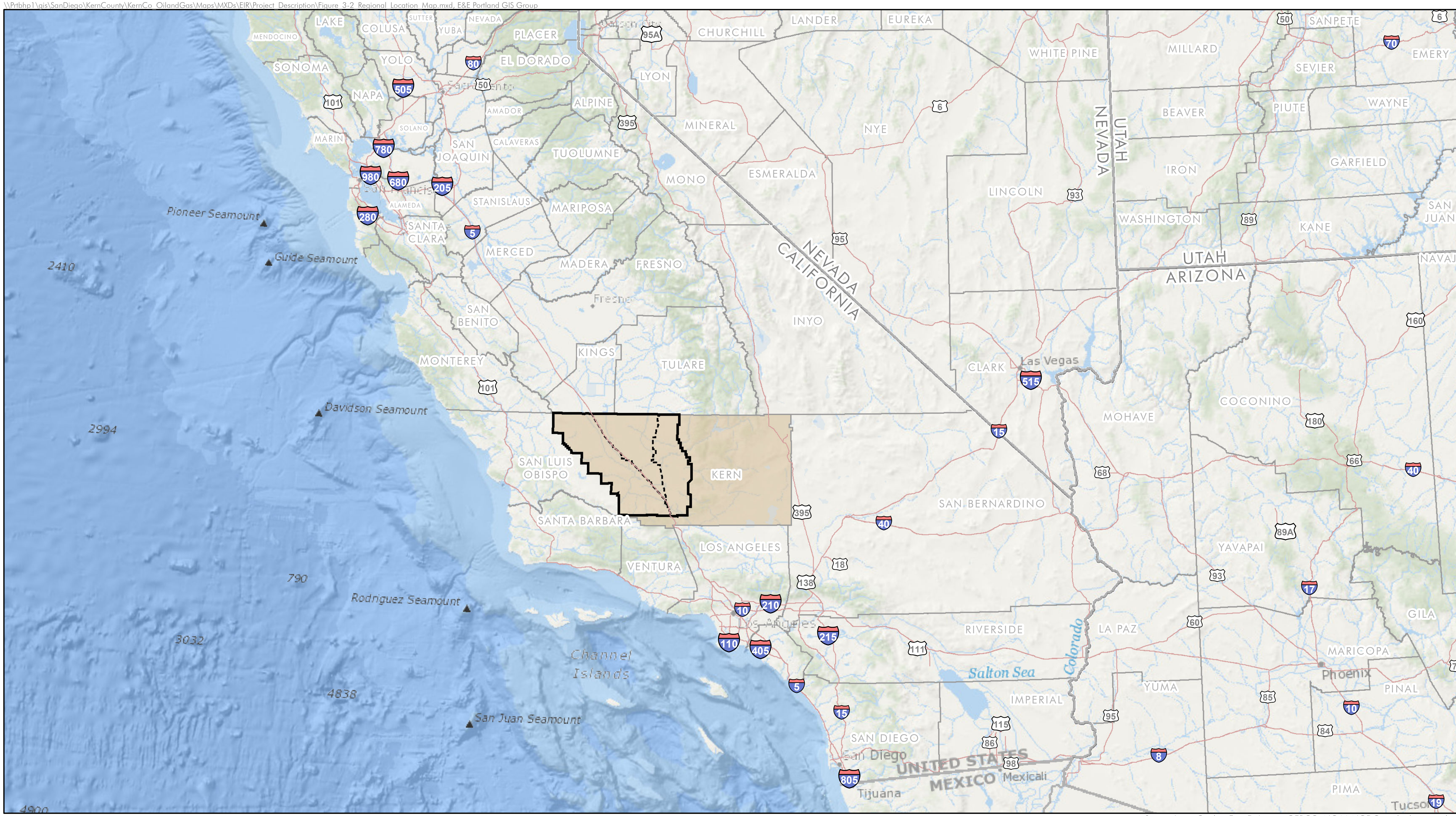

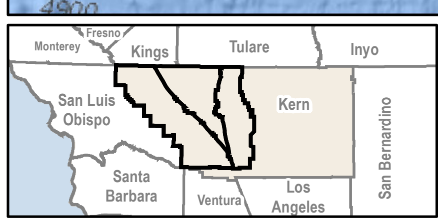

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Miles

Project Boundary
Subarea
Kern County
Highways
County Boundary
State Boundary

Service Layer Credits: Esri, DeLorme, GEBCO, NOAA NGDC, and other contributors
Sources: Esri, GEBCO, NOAA, National Geographic, DeLorme, HERE, Geonames.org, and other contributors
Data Sources: ESRI 2010, Kern County, 2013

Figure 3-2
Regional Location Map

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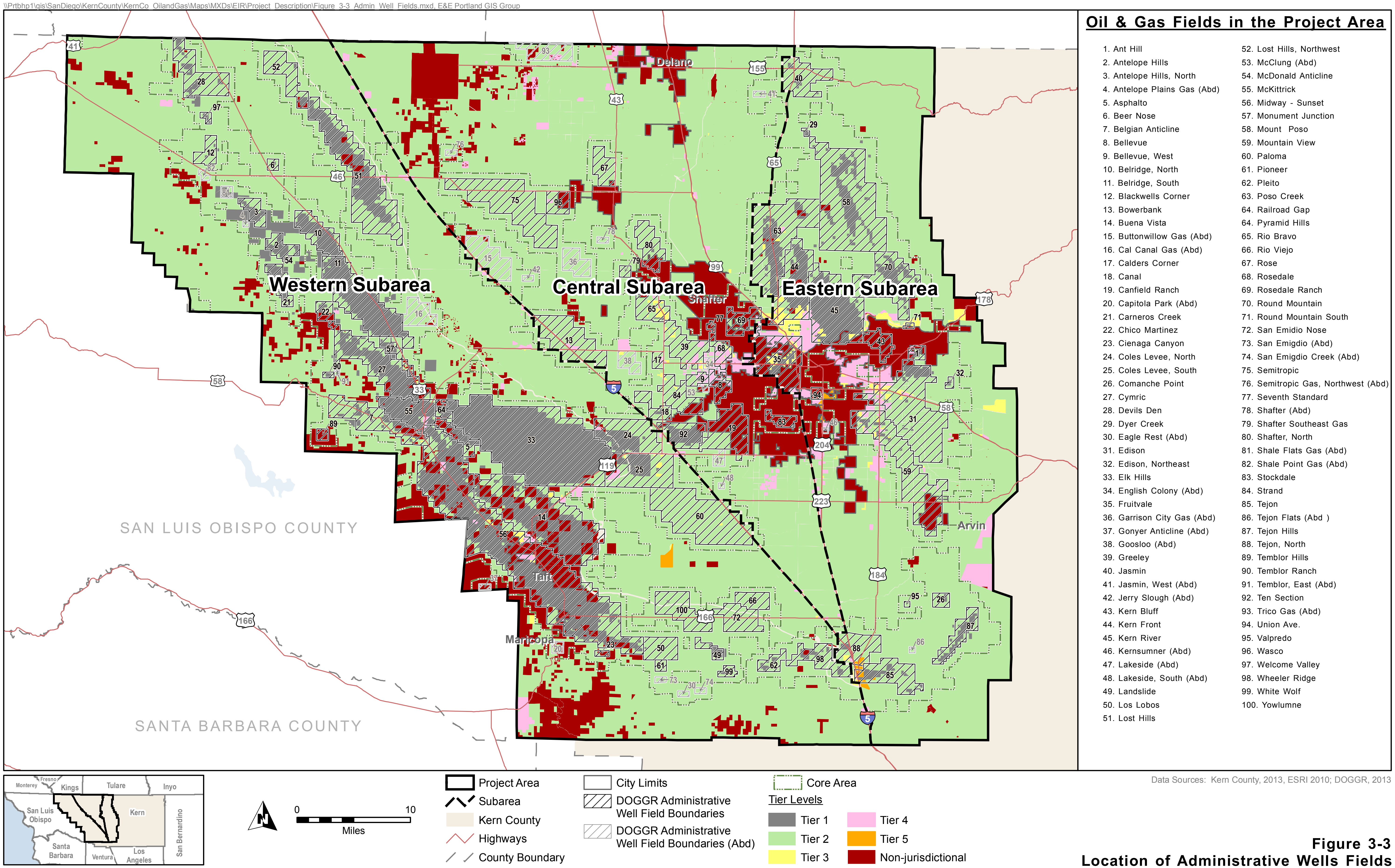

Figure 3-3
Location of Administrative Wells Fields

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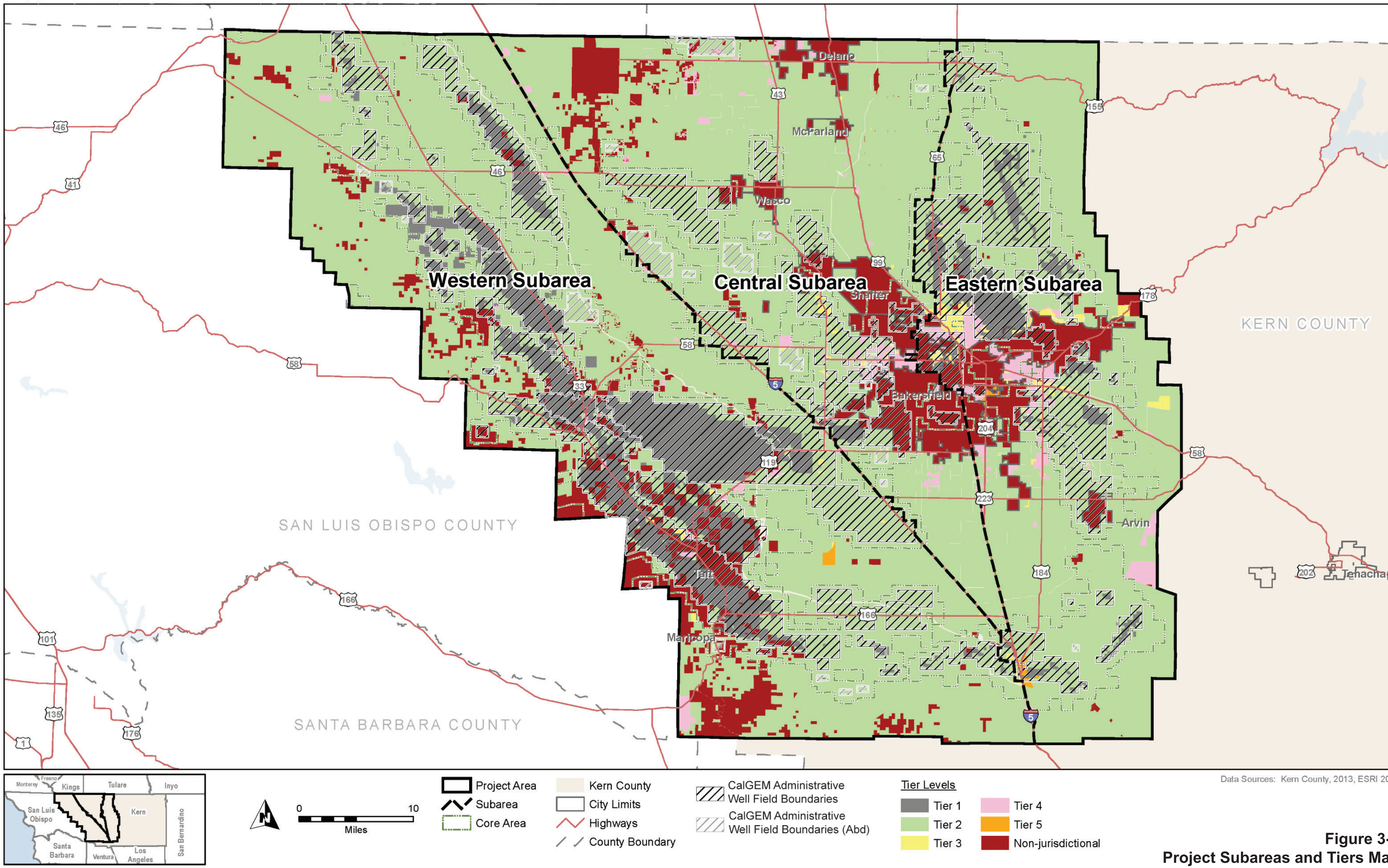

Figure 3-4
Project Subareas and Tiers Map

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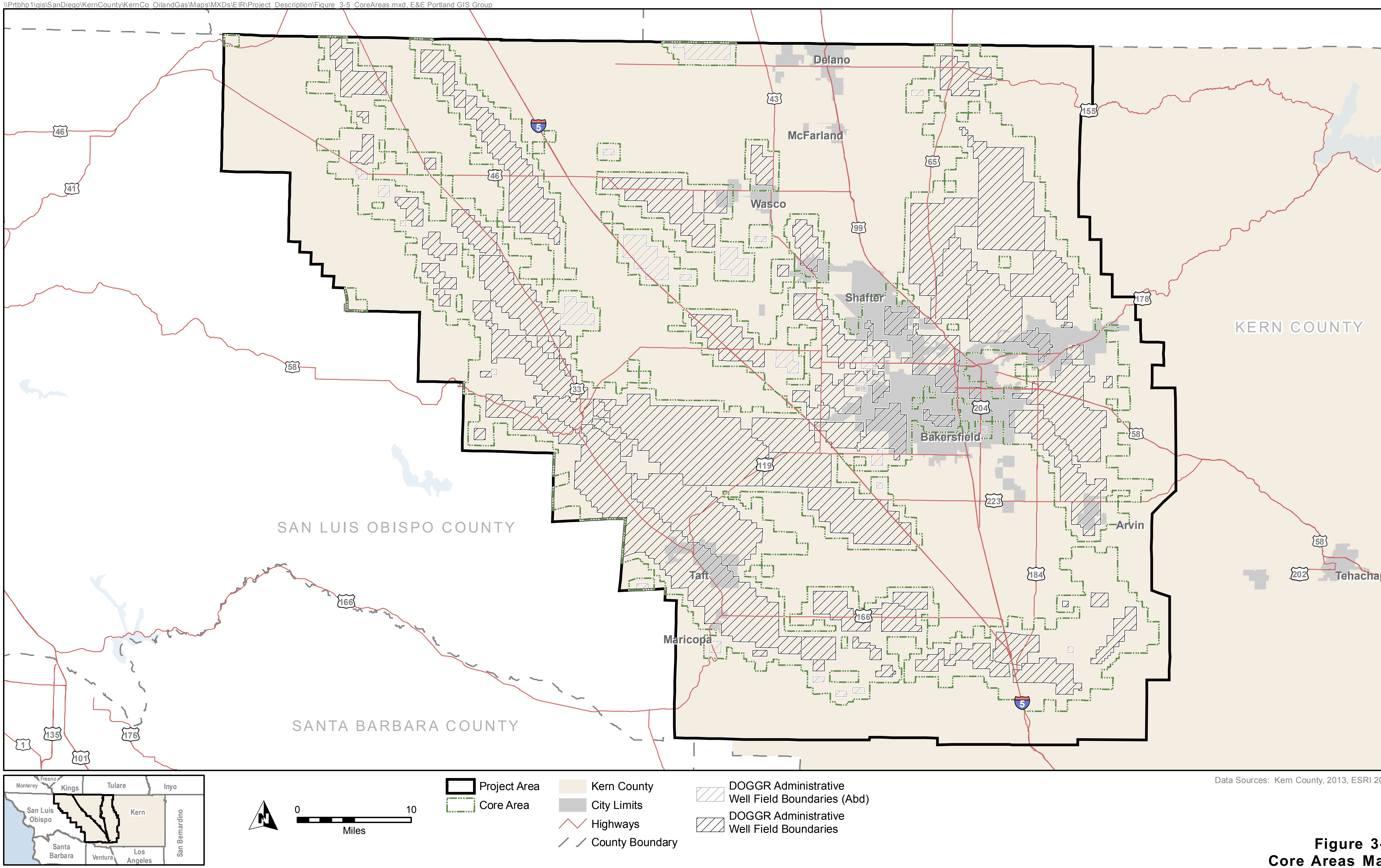

Figure 3-5
Core Areas Map

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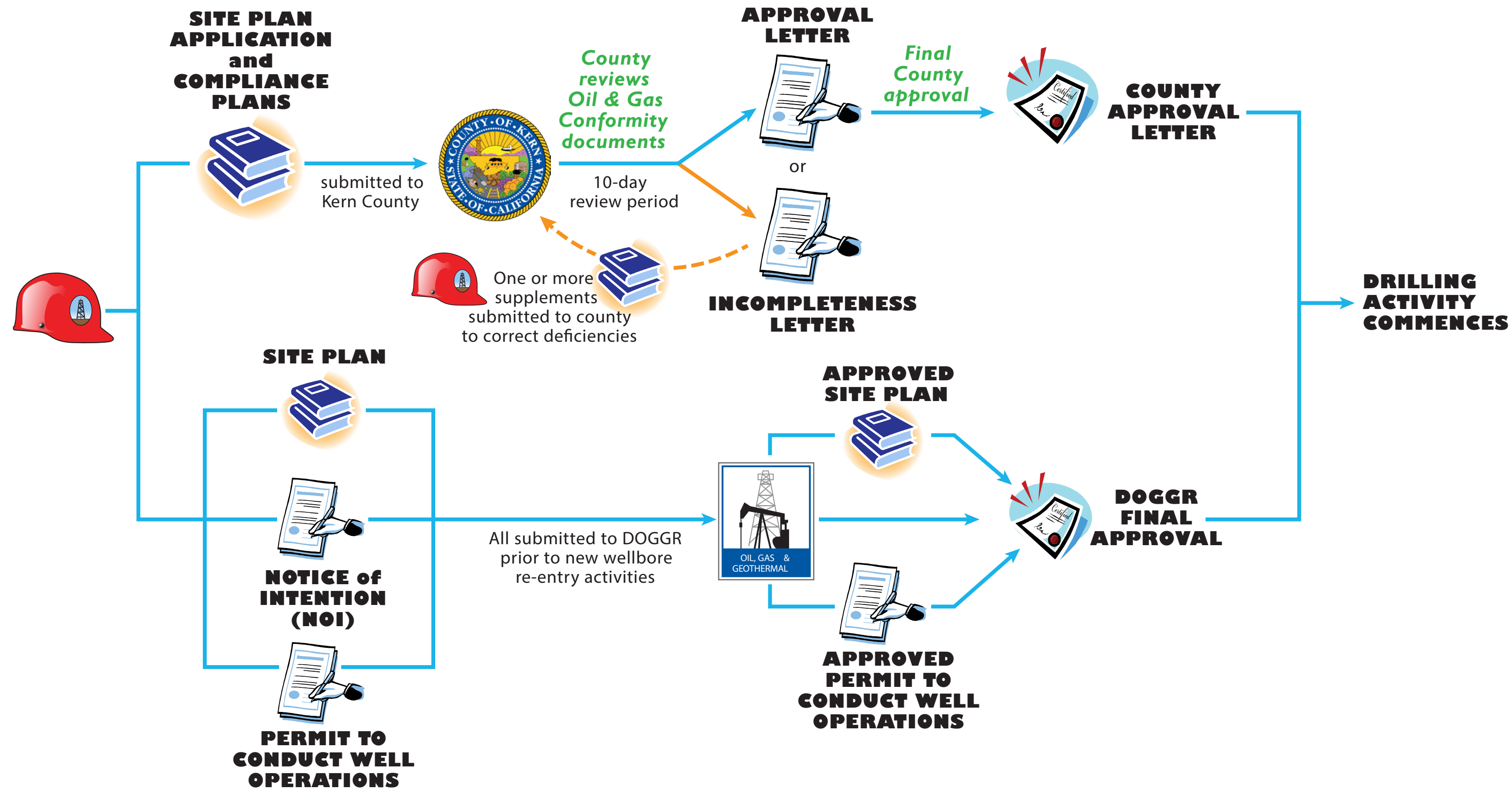
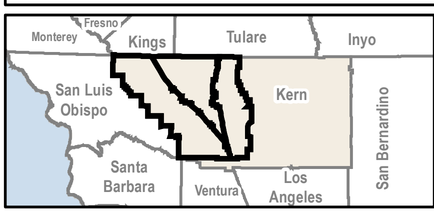
Original Graphic: DL - San Francisco Office.



Note: Process would become mandatory for new oil and gas production activities in Kern County.



LEGEND

Kern County

Operator

Division of Oil, Gas and Geothermal Resources (DOGGR)

Figure 3-6
Oil and Gas Conformity Review Process

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Attachment A

Zoning Ordinance Amendments

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Note: The following text is proposed to replace the current Chapter 19.98 which has been provided as a strikethrough.

All underlined text is as adopted by the Board of Supervisors on November 9, 2015. All *underlined and Italic* text is proposed for change. All strikethoughs are proposed for deletion.

C H A P T E R 19.98

SECTIONS:

19.98.010 PURPOSE AND APPLICATION

The purpose of this chapter is to ensure *the protection of the health, safety and general welfare of communities, residents, and visitors though the permitting of responsible*~~, promote~~ the ~~*economic* and~~ streamlined and *economically viable* recovery of oil, gas, and other hydrocarbon substances in a manner compatible with surrounding land uses. *It establishes* ~~and protection of the public health and safety by establishing~~ reasonable limitations, safeguards, and controls on exploration, drilling, and production of hydrocarbon resources. The procedures and standards contained in this chapter shall apply to all exploration drilling and production activities related to oil, gas, and other hydrocarbon substances carried out within the unincorporated San Joaquin Valley portion of Kern County (See Figure 19.98.015). The effective date of this version of Chapter 19.98 is *XXXXX*. .

19.98.020 DEFINITIONS OF OIL AND GAS PRODUCTION ACTIVITIES

Oil and Gas exploration and operations contain many highly technical activities. For the purposes of this Chapter 19.98, definitions of activities are located throughout the Chapter, where applicable. Unless otherwise indicated in this Chapter, the definitions in Chapter 19.04 remain applicable.

19.98.030 OIL AND GAS PRODUCTION BOUNDARY AREA AND TIER AREAS

Oil and Gas production in Kern County occurs within the portion of Kern County depicted in Figure 19.98.015. This Oil and Gas Activities Boundary Area is divided into five (5) Tier Areas and depicted in Figure 19.98.015. Changes to the Oil and Gas Production Boundary Area and Tier boundaries of Figure 19.98.015 shall be through the procedures in Chapter 19.112.

The Tier Areas were designated based on the following land use planning considerations:

A. Tier 1 Area is defined as all areas in which oil and gas activity is the primary land use. The existing well and activity densities preclude almost all other uses except for passive uses such as grazing.

B. Tier 2 Area is defined as all areas that ~~is~~ are classified Exclusive Agriculture (A) or Limited Agriculture (A-1) Districts, have agriculture as the primary surface land use, and are not included in Tier 1.

C. Tier 3 Area is defined as other areas not within a Tier 1 Area that are located in one of the following zone districts:

- Natural Resource (NR)
- Recreation Forestry (RF)
- Light Industrial (M-1)
- Medium Industrial (M-2)
- Heavy Industrial (M-3)
- Floodplain Primary (FPP)
- Drilling Island (DI)
- Zone Districts that have the Petroleum Extraction (PE) Combining District

D. Tier 4 Area is defined as areas not within Tier 1, 2, or 3, that include at least one of the following zone districts:

- Estate (E)
- Low–Density Residential (R-1)
- Medium-Density Residential (R-2)
- High-Density Residential (R-3)
- Commercial Office (CO)
- Neighborhood Commercial (C-1)
- General Commercial (C-2)
- Highway Commercial (CH)
- Open Space (OS)
- Platted Lands (PL)
- Mobilehome Park (MP)

Authorized oil and gas activities in Tier 4 are subject to approval of a conditional use permit in accordance with 19.104 of this Title.

E. Tier 5 are areas including all current and future Specific Plan boundaries either adopted with a Special Planning (SP) District or which include specific provisions for oil and gas operations. Oil or gas exploration and production activities would be allowed with a conditional use permit or as permitted by the regulations contained within the adopted Specific Plan in Tier 5 areas.

F. All other areas not defined as Tier 1-5 Areas within the Oil and Gas Production Area are considered Non-Jurisdictional because they are not within the jurisdiction of Kern County. ~~Including~~ Land owned by the United States, State of California or land within an incorporated city are exempt, unless under the authority of a written agreement with the Board of Supervisors. The regulations set forth in this chapter pertain only to accessory structures, facilities or uses that are physically connected to, provide access or services to, or otherwise support, oil and gas activities in these Non-Jurisdictional Areas.

19.98.040 OIL AND GAS ACTIVITIES BY MINISTERIAL PERMIT

A. No well for use as an injection well and no well for the exploration for or development or production of oil or gas or other hydrocarbon substances may be drilled, and no related accessory equipment, structure, or facility may be installed in any Tier 1, 2, and 3 Areas until an application for Oil and Gas Conformity Review or Minor Activity Review has been submitted to and approved, *with all adopted fees and mitigation paid* , by the Planning Director as consistent with the standards set out in Section 19.98.060 of this chapter and in accordance with the procedures set out in Sections 19.98.070 through 19.98.120 of this chapter. No such well may be drilled, or related accessory equipment, structure, or facility installed, in a Tier 5 Area unless the Specific Plan procedures for authorizing such activities have been completed, or if no such procedures are included in a Specific Plan unless the Oil and Gas Conformity Review or Minor Activity Review has been submitted and approved consistent with the procedures applicable to Tier 1, 2 and 3 areas.

B. Disposal of nonhazardous oilfield fluid waste and production water is considered an accessory facility only if the facility complies with the following:

1. The nonhazardous oilfield fluid waste or production water is produced and disposed of within the same designated oilfield; or

2. The nonhazardous oilfield fluid waste or production water disposed of outside the designated oilfield of origin is produced by and disposed of solely and only by the same individual, corporation, or entity or by reciprocal agreement among oil and gas operators in Kern County.

C. The provisions of this Section apply to the first three thousand six hundred and forty seven (3,647) new *individual* well permit issued each calendar year, within the Oil and Gas Production Boundary Area. Any new well permits beyond three thousand six hundred and forty seven (3,647) applied for in a calendar year would be subject to a conditional use permit.

19.98.050 OIL AND GAS ACTIVITIES BY CONDITIONAL USE PERMIT

A. In Tier 4, no well for use as an injection well and no well for the exploration for or development or production of oil, gas, or other hydrocarbon substances may be drilled, and no related accessory equipment, structure, facility or use may be installed in any zoning district described in this title in which such uses are permitted as conditional uses, or on land owned by the State of California subject to provisions of 19.98.030, until an application for a conditional use permit, which includes the information specified in Section 19.98.080, has been submitted to and approved by the Planning Commission as consistent with the standards set out in Section 19.98.060 of this chapter and in accordance with the standards and procedures set out in Sections 19.102.130 through 19.102.180 and Chapter 19.98 of this title. In approving a conditional use permit, the Planning Commission may waive any condition set out in Section 19.98.060 of this chapter if it determines that such waiver will not result in material detriment to the public welfare or the property of other persons located in the vicinity, based on findings of fact and compliance with the California Environmental Quality Act.

B. No well for use as an injection well and no well for the exploration for or development or production of oil, gas, or other hydrocarbon substances may be drilled, and no related accessory equipment, structure, or facility, outside the boundaries as defined in Figure 19.98.015, may be installed in any zoning district described in this title in which such uses are permitted, or on land owned by the State of California subject to provisions of 19.98.030, until an application for a conditional use permit, which includes the information specified in Section 19.98.080, has been submitted to and approved by the Planning Commission as consistent with the standards set out in Section 19.98.060 of this chapter and in accordance with the standards and procedures set out in Sections 19.102.130 through 19.102.180 and Chapter 19.98 of this title. In approving a conditional use permit, the Planning Commission may waive any condition set out in Section 19.98.060 of this chapter if it determines that such waiver will not result in material detriment to the public welfare or the property of other persons located in the vicinity, based on findings of fact and compliance with the California Environmental Quality Act.

C. Should any activity requiring approval of an Oil and Gas Conformity Review or Minor Activity Review pursuant to Sections 19.98.070 through 19.98.120 of this chapter, not be able to comply with the Implementation Standards and Conditions set forth in Section 19.98.060, an application for a conditional use permit, which includes the information specified in Section 19.98.080, shall be submitted to and approved by the Planning Commission in accordance with the standards and procedures set out in Sections 19.102.130 through 19.102.180 and Chapter 19.98 of this title. In approving a conditional use permit, the Planning Commission may waive/modify any condition set out in Section 19.98.060 of this chapter if it determines that such waiver or modification will not result in material detriment to the public welfare or the property of other persons located in the vicinity, based on findings of fact and compliance with the California Environmental Quality Act.

D. If a well is not completed upon land subject to a conditional use permit issued pursuant to this chapter and Chapter 19.104 of this title within twelve (12) months from the date of issuance of the permit, or within any approved period thereof, the conditional use permit shall expire and the premises shall be restored as nearly as practicable to their original condition. No permit shall expire while the permittee is continuously conducting drilling, redrilling, completing or abandoning activities, or related operations, in a well on the lands covered by such permit, which activities were commenced while said permit was otherwise in effect. Continuous activities are those suspended for not more than ninety (90) consecutive days. If, at the expiration of the twelve- (12-) month period, the permittee has not completed his drilling program on the lands covered by such permit, the decision making authority, upon a written request of the permittee, may extend the permit for the additional time requested by permittee for the completion of such drilling, in accordance with the standards and procedures set out in Sections 19.102.130 through 19.102.180.

E. The following accessory uses shall require a Conditional Use Permit:
1. Cogeneration facility
2. Landfills

19.98.060 IMPLEMENTATION STANDARDS AND CONDITIONS

Pursuant to this chapter, all activities for the exploration for or development or production of oil, gas, and other hydrocarbon substances and related accessory buildings, structures, facilities, and activities shall comply with the following standards, unless otherwise provided in this chapter:

A. No oil or gas well shall be drilled within *the following distances:*

1. One hundred (100) feet of any public Major or Secondary highway or building not necessary to the operation of the well;
2. Two hundred and ten (210) feet *from the legal parcel property line* of any-sensitive receptor (single or multi-family dwelling unit, place of public assembly *(a legally permitted place where 100 or more people together in a building, or structure, for the purpose of amusement, entertainment or retail sales), churches*, institution, ~~*school*~~ or hospital); or
3. One hundred (100) feet of any building utilized for commercial purposes, not used for oil and gas operations.
4. *Three hundred (300) feet of the legal parcel property line that contains a permitted public or private school. A single family or multi-family dwelling unit that may have home schooling actvitites shall use the single family dwelling unit distance.*

B. All drilling and production activities shall conform to all applicable fire and safety regulations. Firefighting apparatus and supplies required by the Kern County Fire Department shall be maintained on the site at all times during drilling and production operations.

C. All required federal, State, and County rules and regulations shall be complied with at all times, including, but not limited to, the rules and regulations of the following agencies:

1. *California Geologic Energy Management* Division *(CalGEM).* ~~of Oil, Gas and Geothermal Resources~~
2. Kern County Fire Department

3. Kern County Public Health Department
4. Regional Water Quality Control Board
5. San Joaquin Valley Air Pollution Control District
6. Kern County Public Works Department
7. California Department of Fish and Wildlife
8. United States Bureau of Land Management
9. United States Fish and Wildlife Service
10. United States Environmental Protection Agency

D. The applicant shall ~~demonstrate compliance~~ *comply* with all applicable Mitigation Measures *as shown in the steps to compliance checklist* in ~~listed in~~ the approved Mitigation Monitoring and Reporting Program (MMRP) for the Revisions to the Zoning Ordinance (~~C~~ *A*) - ~~2015.~~*2020*

E. Temporary noise attenuation measures shall be allowed in all zone districts with the written permission of the property owner, a specific timeframe for installation and removal and a site plan review with appropriate fees.

19.98.070 OIL AND GAS CONFORMITY REVIEW AND APPROVAL –– REQUIRED

In Tiers 1, 2, 3 and 5, except as provided in this section, no permitted use shall be established, no permitted development shall occur, and no building permit or grading permit shall be issued for any permitted use or development subject to this chapter until an Oil and Gas Conformity Review or Minor Activities Review has been submitted to and approved by the Planning Director in accordance with the procedures set out in Sections 19.102.040 through 19.102.060 of this title.

Oil and Gas Conformity Review and Minor Activities Review

Activity	**Conformity Review**	**Minor Activity Review**	**No Permit Required**
Drilling & Completion			
Exploration or Production Well (including cyclic steam production well) A well drilled for exploration or to produce oil and or natural gas	✓		
Reworked Well	✓		
Injection Well A U.S. Environmental Protection Agency class 2 injection well into which fluids are injected rather than produced with the primary objective typically is to maintain reservoir pressure, conduct EOR operations or dispose of produced water or gas, including: steamflood, waterflood or gas injection	✓		
Observation Well	✓		

Activity	Conformity Review	Minor Activity Review	No Permit Required
A well for the purpose of observing parameters such as temperature, fluid levels and pressure changes			
SB4-Regulated Activities An activity regulated under California Senate Bill 4 (SB4) designed to enhance oil and or gas production or recovery. SB4 activities do not include activities such as steam flooding, water flooding, cyclic steaming, routine well cleanout, well maintenance or removal of formation damage due to drilling, chemical treatments that do not meet the requirements in 584, bottom hole pressure surveys, or routine activity Sidetracking, Deepening, activities that do not affect the integrity of the well of the formation	✓		
Drilling Pit or Sump A drilling pit or sump that requires a permit from the Central Valley Water Quality Control Board	✓		
Sidetrack Change in well type, perforate new or existing perforations in casing, run or remove or cement liners, place or drill out any plug (cement, sand, mechanical): essentially, any operation that permanently alters the casing of a well	✓		
Deepening To deepen or permanently alter the casing in a well. Altering includes actions that require a ~~DOGGR~~ *CalGEM* permit	✓		
Exploration and Development			
Geophysical Survey or Drilling by Scientific Means Tests conducted to determine the extent of and presence of oil and natural gas reserves and whether the resources for development	✓ *	✓	
Well Pad Preparation Construction activity consisting of clearing and grading of a new surface disturbance to	✓ *	✓	

Activity	Conformity Review	Minor Activity Review	No Permit Required
accommodate the well and drilling activity or ancillary facilities that may be required for oil and gas drilling and operations			
Access Road Construction New surface disturbance that occur during the construction of a new road or expansion that includes new surface disturbance	✓ *	✓	
Electric Distribution Line Applies to new surface disturbance that occur during the construction of an electrical distribution line or expansion that includes new surface disturbance	✓ *	✓	
Pipeline Applies to new surface disturbance that occur during the construction of a pipeline or expansion that includes new surface disturbance	✓ *	✓	
Production Operations			
Well Operations and Maintenance Not Requiring a ~~DOGGR~~ *CalGEM* permit			✓
Geophysical Monitoring			✓
Oil/Gas Treatment	✓ *	✓	
Produced Water Treatment	✓ *	✓	
Well Testing			✓
Pipelines	✓ *	✓	
Electric Lines	✓ *	✓	
Wastewater Treatment and Injection Disposal	✓ *	✓	
Wastewater Treatment and Surface Disposal	✓ *	✓	
Waste Treatment and Disposal	✓ *	✓	
Access Road	✓ *	✓	
Vegetation			✓
Reactivation of Idle Wells	✓ *	✓	
Support Facilities			
Administrative Building or Support Facility Building	✓ *	✓	
Steam Generator Boilers that generate steam for oil and gas field production purposes	✓ *	✓	
Flare A gas combustion device used primarily for burning off raw, waste, or unusable flammable gas that cannot be effectively commercialized	✓ *	✓	
Electric Lines	✓ *	✓	

Activity	**Conformity Review**	**Minor Activity Review**	**No Permit Required**
Overhead or buried electrical distribution lines used for oil and gas field operations			
Electric Substations Electric substations used for oil and gas field operations	✓ *	✓	
Pipelines Pipelines that part of an oil and gas field operation	✓ *	✓	
Tanks Tanks used for oil field operations	✓ *	✓	
Oil/Water Treatment Oil/ water treatment equipment used in oil and gas operations	✓ *	✓	
Produced Water Treatment Equipment used to treat produced water in an oil and gas operation	✓ *	✓	
Produced Water Percolation Pond/Sump Produced water percolation and or evaporation ponds permitted by the Central Valley Regional Water Quality Control Board and used during oil and gas field operations	✓ *	✓	
Emergency Pit, Sump or Secondary Containment	✓ *	✓	
Fencing Fencing used to protect and prevent unauthorized individuals from coming into contact with oil and gas equipment and to prevent trespassing			✓
Well Abandonment A ~~DOGGR~~ *CalGEM* process to plug and abandon a well used for oil and or gas activities including production, observation, and injection.	✓ *	✓	
Revegetation The processes taken to establish vegetation at an oil and gas operation			✓
Short Term Employee Housing Short Term Employee Housing Temporary housing for individuals involved in oil and gas operations that require onsite 24 hour 7 day a week oversight	✓ *	✓	

Activity	Conformity Review	Minor Activity Review	No Permit Required
Pre-Ordinance Activities that Cause New Ground Disturbance and/or Subject to the Emission Reduction Agreement	✓ *	✓	
Note: * - Ongoing operations of existing wells, facilities and equipment, including minor modifications such as new interconnections between such facilities, does not trigger conformity review or minor activity review. When these accessory uses, equipment and facilities are proposed as part of the same project as an activity that requires an Oil and Gas Conformity Review, then these accessory activities are required to be included in the Oil and Gas Conformity Review. In all other circumstances, where new ground disturbance occurs, these accessory activities are subject to Minor Activity Review.			

19.98.080 OIL AND GAS CONFORMITY REVIEW — APPLICATION CONTENTS (TIER 1)

Applications for an Oil and Gas Conformity Review within Tier 1 Areas, pursuant to Section 19.98.040 of this chapter shall include the following:

A. Name, telephone number and address of the applicant.

B. Name(s), telephone number(s) and address(es) of the surface property owner(s), mineral owner(s), oil and gas operator (if different than the applicant).

C. Assessor's parcel number(s) of all parcels located within the boundaries of the proposed operation, including accessory equipment, structures, and/or facilities. Latitude/Longitude coordinates for all existing and proposed wells.

D. Description of the project area, including total site acreage, accessory equipment, structures, and/or facilities.

E. A site plan drawn to scale, sufficient in size to show all necessary details, no larger than 11x17, with multiple sheets (if necessary), which includes the following information:

1. Project boundary lines and dimensions, including lease lines and property lines *and site size in square feet and acres.*

2. Location and coordinates of all proposed well holes and related accessory equipment. Location of all roadways, pipelines, tanks, treatment or other structures and facilities to be installed. Distance from proposed well holes to section/midsection lines, located within ½ mile.

3. Location of all existing dwellings and structures, located within *four thousand (4,000) feet* ~~fifteen hundred and fifty (1,550) feet for all wells proposed to be drilled less than ten thousand (10,000) feet in depth or located within three thousand two hundred and seventy (3,270) feet, for all wells proposed to be drilled greater than ten thousand (10,000) feet in depth,~~ of the proposed well holes. Identification of the use of each structure, and distances between well holes and existing buildings

shall be noted. *The location of the nearest sensitive receptor shall be shown in both feet and with coordinates*. Location of existing property lines and distance from well site to property line.

4. Location of all new flare gas production lines, lines for production, electrical lines, and location of tank farms to be used.

5. North arrow, date the site plan was prepared, and scale.

6. Location of all accessory/ancillary facilities (including trucking parking, onsite storage, etc.) to be installed with the proposed wells.

7. California *Geologic Energy Management* Division ~~of Oil, Gas and Geothermal Resources~~ permit application number, if available.

8. Identify the proposed source of water (domestic or production), if applicable.

9. Show location of all proposed underground pipelines.

10. Location of any existing Oil and Gas Conformity Review boundaries within and/or contiguous to the proposed boundary, including total site acreage and identification of Tier Area.

~~11.~~ Written documentation ~~*in sufficient detail*~~ to allow the County to determine that all conditions required in Section 19.98.060 will be complied with, including all applicable mitigation measures as listed in the approved Mitigation Monitoring and Reporting Program for the Revisions to the Zoning Ordinance (~~C~~ A) – ~~2015.~~2020

12. Evidence that notice was provided to Land/Surface Owners as required by Section 19.98.080 G.

G. Notification Requirements

1. A physical letter of notification of application that requires a signature for delivery shall be sent by the applicant to all Land/Surface Owners of the property for which the Conformity Review is being requested, if the Land/Surface Owners are different from the mineral owners. The notice shall include all information required by State law. The letter of notification package shall include a copy of proposed site plan, including an official County handout explaining the conformity review process. The package shall be sent 30 days before submittal of the application. The application shall include evidence that the letter was sent and the signatures received. Any application for which the Land/Surface Owner letter is returned for failure to obtain a signature, the Applicant shall provide evidence that the Land/Surface Owner of the property cannot be located through normal means such as tax records. A dated letter of authorization, with specific Assessor Parcel Numbers and the period of time applicable, from the Land/Surface Owner addressed to the County of Kern may be submitted asking that the notification be waived as allowed by State law. In site locations where mineral

rights are owned by the United States Government and the surface is privately owned, the application package shall include confirmation that the proposed site plan has been submitted to the United States Bureau of Land Management.

2. A second letter shall be sent, by the applicant, when the application is submitted to the County. A dated letter of authorization, with specific Assessor Parcel Numbers and the period of time applicable, from the Land/Surface Owner, addressed to the County of Kern, may be submitted asking that the notification of application submitted be waived.

3. Access of the surface for purposes of conducting pre-application activities, such as surveys, shall be subject to any existing agreement between the Mineral Owner and the Land/Surface Owner, and State regulations. Such access is not subject to the notification requirements set forth in this title.

19.98.085 OIL AND GAS CONFORMITY REVIEW AND CONDITIONAL USE PERMIT — APPLICATION CONTENTS (TIERS 2-5)

Applications for an Oil and Gas Conformity Review within Tiers 2, 3, or Tier 5 Areas, pursuant to Section 19.98.040 of this chapter, or for a conditional use permit, for oil and gas activities within a Tier 4 Area, pursuant to Section 19.98.050 of this chapter, shall include the following:

A. Name, telephone number and address of the applicant.

B. Name(s), telephone number(s) and address(es) of the surface property owner(s), mineral owner(s), oil and gas operator (if different than the applicant).

C. Assessor's parcel number(s) of all parcels located within the boundaries of the proposed operation, including accessory equipment, structures, and/or facilities. Latitude/Longitude coordinates for all existing and proposed wells.

D. Preliminary Title Report, not over ninety (90) days old. A Guarantee of Title may be submitted for parcels with a Preliminary Title Report on file, over (90) days old.

E. Legal description of the project area, including total site acreage, located within the boundaries of the proposed operation, including accessory equipment, structures, and/or facilities in aliquot format, unless a more precise legal description is determined to be needed by the Planning Director.

F. A site plan drawn to scale, sufficient in size to show all necessary details, no larger than 11x17, with multiple sheets (if necessary), which includes the following information:

   1. Topography and proposed grading of the site plan.

   2. Project boundary lines and dimensions, including lease lines and property lines lines *and site size in square feet and acres.*

3. Location and coordinates of all proposed well holes and related accessory equipment. Location of all roadways (access roads), any proposed landscaping, pipelines, tanks, treatment or other structures and facilities to be installed, and any existing or abandoned wells if such are known to exist.

4. Location of all existing dwellings and structures, located within *four thousand (4,000) feet* ~~fifteen hundred and fifty (1,550) feet for all wells proposed to be drilled less than ten thousand (10,000) feet in depth or located within three thousand two hundred and seventy (3,270) feet, for all wells proposed to be drilled greater than ten thousand (10,000) feet in depth,~~ of the proposed well holes. Identification of the use of each structure, and distances between well holes and existing buildings shall be noted. *The location of the nearest sensitive receptor shall be shown in both feet and with coordinates*. Location of existing property lines and distance from well site to property line.

5. Location of all new flare gas production lines, lines for production, electrical lines, and location of tank farms to be used.

6. North arrow, date the site plan was prepared, and scale.

7. Location of all recorded easements onsite, roads, section/midsection lines, located within ½ mile of the proposed wells.

8. Location of all accessory/ancillary facilities (including trucking parking, onsite storage, etc.) to be installed with the proposed wells. Location of planned ground disturbance on irrigated or prime agricultural land.

9. Description of project boundary in relation to Tier areas as defined in Figure 19.98.015.

10. California *Geologic Energy Management* Division ~~of Oil, Gas and Geothermal Resources~~ permit application number, if available.

11. Identify the location of the 100-year floodplain, if applicable.

12. Identify the proposed source of water (domestic or production), if applicable.

13. Show location of all new proposed underground pipelines.

14. Location of any existing Oil and Gas Conformity Review boundaries within and/or contiguous to the proposed boundary.

15. Written documentation ~~*in sufficient detail*~~ to allow the County to determine that all conditions required in Section 19.98.060 will be complied with, including all applicable mitigation measures as listed in the approved Mitigation Monitoring and Reporting Program for the Revisions to the Zoning Ordinance (C) – 2015.

16. Evidence that notice was provided to Land/Surface Owners as required by Section 19.98.085 H.

G. Signature Block and Statement (Land/Surface Owner, Mineral Owner and Operator. The following statement shall be included ~~to~~on the first page of the site plan. The statement shall be signed by all parties, irrespective of ownership relationship. Multiple lines may be added for multiple ownership signatures. A dated letter of authorization, with specific Assessor Parcel Numbers, from the Land/Surface Owner addressed to the County of Kern may be submitted asking that the signature on the site plan be waived.

REQUIRED STATEMENT

The undersigned Land/Surface Owner is the owner of APN#_______________. The undersigned is the Mineral Owner and/or Operator or Lessee of the Mineral Owner. The Land/Surface Owner and the Mineral Owner and/or the Operator or Lessee have come to an agreement regarding the use of the surface of the property in connection with the Kern County permit that is being issued with this site plan.

Land/Surface Owner:	Mineral Owner:	Operator:
Print Name	Print Name	Print Name
Title/Company	Title/Company	Title/Company
Signature	Signature	Signature
Date	Date	Date

H. Notification Requirements – Tier 2, 3, 4 and 5 Areas.

1. A physical letter of notification of application that requires a signature for delivery shall be sent by the applicant to all Land/Surface Owners of the property for which the Conformity Review is being requested, if the Land/Surface Owners are different from the mineral owners. The notice shall include all information required by State law. The letter of notification package shall include a copy of proposed site plan, and invitation to the Land/Surface Owner(s) offering a meeting with the Mineral Owner or Operator, and including an official County handout explaining the conformity review process. The package shall be sent 30 days before submittal of the application. The application shall include evidence that the letter was sent and the signatures received. Any application for which the Land/Surface Owner letter is returned for failure to obtain a signature, the Applicant shall provide evidence that the Land/Surface Owner of the property cannot be located through normal means such as tax records. A dated letter of authorization, with specific Assessor Parcel Numbers and the period of time applicable, from the Land/Surface Owner addressed to the County of Kern may be submitted asking that the notification be waived as allowed by State law. In site locations where mineral rights are owned by the United States Government and the surface is privately owned, the application package shall include confirmation that the

proposed site plan has been submitted to the United States Bureau of Land Management.

2. Access of the surface for purposes of conducting pre-application activities, such as surveys, shall be subject to any existing agreement between the Mineral Owner and the Land/Surface Owner, and State regulations. Such access is not subject to the notification requirements set forth in this title. On split estates, it is the intent of the County that the decisions generated by this Ordinance only apply to the mineral estate. No decisions generated by this Ordinance shall change the existing rights or authority of the private surface owners to full use and enjoyment of their property under laws and regulations in effect prior to the effective date of this Ordinance, or change the existing rights or authority of the mineral owner to pursue mineral exploration and production except to require compliance with this Ordinance. The right to enter split estate private surface lands to permit oil and gas operations shall be consistent with existing law or as limited by private agreement between the parties. The right to enter split estate private surface lands by individuals or entities for purposes of conducting biological and cultural resource surveys is limited to those individuals or entities under contract to, and liable to, the mineral owner/operator, and is further limited to the locations of existing or planned oil and gas activities, and such adjacent areas required by survey protocols for relevant species.

19.98.090 OIL AND GAS CONFORMITY REVIEW – WITH APPLICABLE SURFACE OWNER SIGNATURE

A. An applicant for a ministerial Oil and Gas Conformity Review permit pursuant to this chapter shall submit an application to the Planning Director in the format and number of copies specified by the Planning Director. The application shall contain all the information specified for the application by the applicable section of this chapter. The application shall be accompanied by the fee established by the Board of Supervisors pursuant to Section 19.06.040 of this Title. For Tier 2, 3 and 5 Areas, a copy of the application shall be provided to the Land/Surface owner per the requirements of 19.98.085.H above. The application must contain the signature block and statement pursuant to Section 19.98.085.G, or shall contain a letter from the Land/Surface Owner waiving the need for said signature on the specified parcel of the proposed application. The waiver letter must be dated and provide specific language as to the length of time the letter is valid if to be used for future Oil and Gas Conformity Reviews.

B. The Planning Director shall inform the applicant in writing within seven (7) business days of receipt that the application is complete and shall issue the permit if he/she determines that the proposed use meets the implementation standards and conditions specified in the applicable provisions of this chapter or inform the applicant that additional information is needed to complete the application and therefore the application is deemed incomplete.

C. Within three (3) business days of reviewing the second submittal, if required, to correct any deficiencies, the Planning Director shall issue the permit if he/she determines that the proposed use meets the implementation standards and conditions specified in the applicable provisions of this chapter or inform the applicant that additional information is needed to complete the application and therefore the application is deemed incomplete.

D. Within seven (7) business days of reviewing the third submittal to correct any deficiencies, the Planning Director shall issue the permit if he/she determines that the proposed use meets the implementation standards and conditions specified in the applicable provisions of chapter. If the application remains incomplete, a mandatory in person meeting with the applicant, and any consultant processing the application on behalf of the applicant, will be required to resolve the issues preventing issuance of the permit. The in-person meeting cannot be waived, and shall be held at the Kern County Planning and ~~*Community Development*~~ *Natural Resources* Department.

E. Failure of the Planning Director to meet any deadline for application review or permit issuance as provided in this section shall not cause a permit to be deemed approved.

F. Any reviews beyond three (3), as provided above, shall require additional fees to be paid, as set forth pursuant to Section 19.06.040 of this Title, and shall be completed within thirty (30) days after the application is deemed complete.

G. Prior to conducting any drilling activity, the applicant (or operator, if acting on behalf of an applicant) must have received and have on file both the approved Permit to Conduct Well Operations from California *Geologic Energy Management* Division of ~~Oil, Gas and Geothermal Resources~~ and an approved Oil and Gas Conformity Review unless the activity involves facility placement not subject to California *Geologic Energy Management* Division ~~of Oil, Gas and Geothermal Resources~~ permit approval.

H. Upon issuance of this permit:

1. The County shall send a notification to the applicant, applicable responsible agencies, and the land/surface owner (if different from the mineral owner) stating a permit has been issued by the County. The approval letter shall include a stamped site plan, list of applicable conditions and mitigation measures, and a determination that the permit approval falls within the scope of the Environmental Impact Report prepared for the Revisions to the Zoning Ordinance (C) – 2015, and that other state, regional, and local agencies are responsible agencies under the California Environmental Quality Act.

2. The applicant shall notify the Land/Surface owner of the proposed dates for access of the property to commence operations and/or to comply with mitigation measures. Such notification may take the form of multiple letters. A dated letter of authorization, with specific Assessor Parcel Numbers and the period of time applicable, from the Land/Surface Owner, addressed to the County of Kern, may be submitted asking that the notification of access be waived or has already been satisfied with a single notification letter.

I. If the development for which a permit has been approved pursuant to this article has not commenced within one (1) year of the granting of the permit, or if the permit has been unused, abandoned, discontinued, or has ceased for a period of one (1) year, the permit shall become null and void and of no effect, unless an extension has been granted by the Planning Director upon written request with *the adopted fee* for an extension before the expiration of the one- (1-

) year period. *Only one extension may be granted for an approved permit.* A copy of any expiration or extension shall be provided to the Land/Surface Owner.

19.98.100 OIL AND GAS CONFORMITY REVIEW - WITHOUT REQUIRED SURFACE OWNER SIGNATURE

The provisions contained in this section apply only to applications submitted within Tier 2, 3 and 5 Areas, which do not contain the surface owner signature as required by Section 19.98.070, above:

A. An applicant for a ministerial Oil and Gas Conformity Review permit pursuant to this chapter, which does not include the Land/Surface Owner signature required pursuant to Section 19.98.085 F, shall submit an application to the Planning Director in the format and number of copies specified by the Planning Director. The application shall contain all the information specified for the application by the applicable provisions of this chapter. A copy of the application shall be provided to the Land/Surface Owner per the requirements of Section 19.98.080.F above. The application shall be accompanied by the fee established by the Board of Supervisors pursuant to Section 19.06.040 of this Title.

B. The Planning Director shall inform the applicant in writing on the thirtieth (30) calendar day of receipt that the application is complete or that additional information is needed to complete the application and therefore the application is deemed incomplete. The Planning Director shall notify the Surface/Land Owner of their option for an in-person meeting with the Department to discuss the conformity review process and answer questions regarding the site plan, to be scheduled within the thirty (30) day period stated above.

C. Second Thirty (30) Day Review Period.

1. If the application is deemed complete during the thirty (30) day period in Section 19.98.100 B, a mandatory second thirty (30) calendar day review will commence immediately following the end of the first review period.

2. If the application is found to be incomplete during the review period in Section 19.98.100 B, a subsequent thirty (30) day review period will commence at the time of submittal by the Applicant of the additional documentation.

3. The Planning Director shall notify the Surface/Land Owner of their option for an additional in-person meeting with the Department to answer questions including review of any revisions to the site plan, to be scheduled within the thirty (30) day period stated above.

4. The Planning Director shall request to schedule a mandatory in-person meeting with the Applicant to review the current site plan and discuss the conformity review process.

5. On the first business day following the 30 day review period, the Planning Director shall issue the permit if he/she determines that the proposed use meets the implementation standards and conditions specified in the applicable provisions of this chapter or inform the applicant that additional information is needed to complete the application and therefore the application is deemed incomplete.

D. All subsequent reviews, due to incomplete application submittals, shall require a mandatory thirty (30) calendar day review period. The Planning Director shall issue the permit if he/she determines that the proposed use meets the development standards and conditions specified in the applicable provisions of this chapter or inform the applicant that additional information is needed to complete the application and therefore the application is deemed incomplete. If application remains incomplete, a mandatory in-person meeting with the applicant, and any consultant processing the application will be required to resolve the issues preventing issuance of the permit. The in-person meeting cannot be waived.

E. Any reviews beyond three (3), as provided above, shall require additional fees to be paid, as set forth pursuant to Section 19.06.040 of this Title, and shall be completed within thirty (30) days after the application is deemed complete.

F. At any time during the review periods in Sections 19.98.100.A through D the applicant submits proof of the required surface owner signature on the site plan, the application will be deemed acceptable to be processed under the provisions set forth in Section 19.98.090.

G. Failure of the Planning Director to meet any deadline for application review or permit issuance as provided in this section shall not cause a permit to be deemed approved.

H. No sooner than thirty (30) calendar days from issuance of the Kern County Oil and Gas Conformity Review and any other necessary state or federal permits, the applicant may begin construction of the facility. This period shall be used to coordinate deposits and inspections pursuant to 19.98.140 (Inspection Compliance). Prior to conducting any drilling activity the operator must have received and have on file both the approved Permit to Conduct Well Operations, from California Division of Oil, Gas and Geothermal Resources and an approved Oil and Gas Conformity Review unless the activity involves facility placement not subject to California Division of Oil, Gas and Geothermal Resources permit approval.

I. Upon issuance of this permit:

1. The County shall send a notification to the Applicant, applicable responsible agencies, and the Land/Surface Owner stating a permit has been issued by the County. The approval letter shall include a stamped site plan, list of applicable conditions and mitigation measures, and a determination that the permit approval falls within the scope of the Environmental Impact Report prepared for the Revisions to the Zoning Ordinance (C) – 2015, and that other state, regional, and local agencies are responsible agencies under the California Environmental Quality Act.

2. The Applicant shall notify the Land/Surface owner of the proposed dates for access of the property to commence operations and/or to comply with mitigation measures. Such notification may take the form of multiple letters.

J. If the development for which a permit has been approved pursuant to this article has not commenced within one (1) year of the granting of the permit, or if the permit has been unused, abandoned, discontinued, or has ceased for a period of one (1) year, the permit shall become null and void and of no effect, unless an extension has been granted by the *Planning Director* ~~decision-making~~ ~~authority~~ upon written request *with the adopted fee* for an extension before the expiration of the one- (1-) year period. *Only one extension may be granted for an approved permit*. A copy of any expiration or extension shall be provided to the Land/Surface Owner.

19.98.110 MINOR ACTIVITY REVIEW — APPLICATION CONTENTS

An application for Minor Activity Review ministerial permit for Tier 1-3 and 5 Areas, pursuant to Section 19.98.040 of this chapter, shall include the following:

A. Name, telephone number and address of the applicant.

B. Name(s), telephone number(s) and address(es) of the property owner(s), mineral owner(s), oil and gas operator (if different than the applicant).

C. Assessor's parcel number(s) of all parcels located within the boundaries of the proposed operation, including accessory equipment, structures, and/or facilities. Latitude/Longitude coordinates for all wells.

D. Preliminary Title Report, not over ninety (90) days old. A Guarantee of Title may be submitted for parcels with a Preliminary Title Report on file, over (90) days old. For all Tier 2-5 Applications only.

E. Description of proposed oil and gas activity and written documentation ~~*in sufficient detail*~~ to allow the County to determine that all conditions required in Section 19.98.060 will be complied with, including all applicable mitigation measures as listed in the approved Mitigation Monitoring and Reporting Program for the Revisions to the Zoning Ordinance (C) – 2015.

F. Sufficient number of photographs to identify the extent of existing ground disturbance.

G. For Tier 2, 3 and 5 Areas only, documentation of a letter submitted to the Land/Surface Owner(s), if different from the Mineral Owner, informing the Land/Surface owner of the Minor Activity Review application and providing a complete copy of the application, shall be mailed and received a minimum of thirty (30) days prior to application being submitted to the County for review.

19.98.120 MINOR ACTIVITY REVIEW

A. An applicant for a Minor Activity Review ministerial permit for Tiers 1-3, and 5, pursuant to this chapter shall submit an application to the Planning Director in the format and number of copies specified. The application shall contain all the information specified for the application by the applicable section of this chapter. The application shall be accompanied by the fee established by the Board of Supervisors pursuant to Section 19.06.040 of this Title. For Tier 2, 3 and 5 Areas, a copy of the application shall be provided to the Land/Surface Owner per the requirements of Section 19.98.080.F above.

B. The Planning Director shall to inform the applicant in writing within seven (7) business days of receipt that the application is complete and shall issue the permit if he/she determines that the proposed use meets the development standards and conditions specified in the applicable provisions of this chapter or inform the applicant that additional information is needed to complete the application and therefore the application is deemed incomplete.

C. Within three (3) business days of reviewing the second submittal, if required, to correct any deficiencies, the Planning Director shall issue the permit if he/she determines that the proposed use meets the development standards and conditions specified in the applicable provisions of this chapter or inform the applicant that additional information is needed to complete the application and therefore the application is deemed incomplete.

D. Within seven (7) business days of reviewing the third submittal, if required, to correct any deficiencies, the Planning Director shall make reasonable efforts to issue the permit if he/she determines that the proposed use meets the development standards and conditions specified in the applicable provisions of Title. If additional information is needed, a mandatory in-person meeting with the applicant, and any consultant processing the application will be required to resolve the issues preventing issuance of the permit. The in-person meeting cannot be waived.

E. Failure of the Planning Director to meet any deadline for application review or permit issuance as provided in this section shall not cause a permit to be deemed approved.

F. Any reviews beyond three (3), as provided above, shall require additional fees to be paid, as set forth pursuant to Section 19.06.040 of this Title, and shall be completed within thirty (30) days after the applicant is deemed complete.

G. Prior to conducting any activity the operator must have received and have on file both approved applicable California *Geologic Energy Management* Division ~~of Oil, Gas and Geothermal Resources~~ permit(s), if necessary, and an approved Minor Activity Review pursuant to the chapter.

H. Upon issuance of this permit, the County shall send a notification to the applicable responsible agencies stating a permit has been issued by the County and that the agency has certain requirements under the California Environmental Quality Act as a responsible agency.

I. If the development for which a permit has been approved pursuant to this article has not commenced within one (1) year of the granting of the permit, or if the permit has been unused, abandoned, discontinued, or has ceased for a period of one (1) year, the permit shall become null and void and of no effect, unless an extension has been granted by the *Planning Director* ~~decision-making authority~~ upon written request *with the adopted fee* for an extension before the expiration of the one- (1-) year period. A copy of any expiration or extension shall be provided to the Land/Surface Owner.

19.98.130 SELF-CERTIFICATION

Upon issuance of Oil and Gas Conformity Review or Minor Activity, as specified in Sections 19.98.090 and 19.98.120 of this chapter, and any other necessary state or Federal permits, the applicant may begin construction of the facility. The provisions of this section do not apply to issuance of an Oil and Gas Conformity Review pursuant to 19.98.100 (Oil and Gas Conformity Review - Without Required Surface Owner Signature) of this chapter. The applicant must self-certify compliance with Chapter 19.98 during the construction and operation process. Once the project applicant has completed the construction of the oil and gas facilities, as indicated on the approved site plan, the project applicant ~~will~~ *shall* provide a self-certified statement,and signed *job card* , in writing, to the County, in a format specified by the Director *within 30 days of completion of the work.*

During construction and continued operations of the activities specified by the approved site plan, the applicant will be responsible for complying with the issued Oil and Gas Conformity Review, and all applicable implementation standards as outlined in this chapter. Should a violation of a permit issued under this chapter occur on-site, a Certification and Finalization process for the Oil and Gas Conformity Review will be conducted by the County Oil and Gas Inspector, and self-certification for the permit will no longer be permitted for the applicant for the next issued permit, as a probationary period. Once the applicant has demonstrated compliance on the following permit, any subsequent permit may be self-certified.

19.98.140 INSPECTION COMPLIANCE – *Section - 19.98.100 (Oil and Gas Conformity Review – Without Required Surface Owner Signature)*

Upon receipt of an issued permit pursuant to Section 19.98.100 (Oil And Gas Conformity Review - Without Required Surface Owner Signature), the applicant must contact the Planning and *Natural Resources* ~~*Community*~~ Development Department and the Public Works Department to pay pursuant to Section 19.06.040 of this title and provide a signed Cost Recovery Agreement, *and submit a video surveillance plan to be implemented* ~~and schedule an inspector to be present~~ during all activities related to the Oil and Gas Conformity Review. ~~The County inspector or third-party building inspector retained by the County shall confirm compliance with all requirements of this Title and Mitigation Measures, and other federal and State laws~~. All compliance verification costs shall be incurred by the applicant, including any costs for requested onsite inspections by environmental resource experts *such as biological or cultural monitors* to confirm or resolve compliance issues. During construction for all activities specified by the approved site plan, *the video surveillance plan shall be operational to monitor and provide for review by staff* ~~*to enforce*~~ *to confirm* the applicant's compliance with the issued Oil and Gas Conformity Review, and all applicable standards and conditions as outlined in the permit. The applicant's ~~may submit a request along~~ ~~with a~~ surveillance plan, *can be submitted without surface owner agreement*, as long as there is no residence on the property. *If there is a residence on the property*, ~~unless~~ the surface owner must be consulted and agree~~s~~ to the *plan details on the location of cameras and* ~~*The plan*~~ ~~*which shall*~~ ~~*include*~~ *the details to ensure the privacy of the residence is not compromised by the placement of the video survillence*. *If a resolution can not be reached on the survillence plan with the surface owner for a property that contains a residence*, *the Planning Director shall make a final determination on the details of the plan after a meeting with the surface owner*. ~~for consideration by the Planning Director,~~ ~~*after and*~~ ~~*evidence that it has been sent to the surface owner to allow for comments to the Department during consideration.*~~ The Plan shall outline the use of onsite cameras with real-time surveillance or 24-hour a day taped or other surveillance methods approved by the Planning Director, in conjunction with review and/or potential onsite inspections *by staff*, the County Inspector or third-party inspector retained by the County. Throughout operations of the activities specified by the approved site plan, the applicant shall comply with the issued Oil and Gas Conformity Review, and all applicable standards and conditions as outlined in the permit.

19.98.145 IDLE WELLS

A. An operator shall file a notification with the County, and with the Surface/Land Owner (if different from the Mineral Owner) of any Idle or Long Term Idle Well, within 30 days of changing the well status in Tier 2 through 5.

B. For purposes of this section, a "Idle Well" is defined as a well that has not produced oil or natural gas, or has not been used for injection for six consecutive months of continuous operation during the last five or more years. A "Long-Term Idle Well" means any well that has not produced oil or natural gas, or has not been used for injection for six consecutive months of continuous operations during the last 10 or more years. An "active observation well" means a well being used for the sole purpose of gathering reservoir data, such as pressure or temperature in a reservoir being currently produced or injected by the operator, and the data is gathered at least once every three years. An Idle well or Long-Term Idle Well does not include an active observation well.

C. Any well operator, land owner or resident within one mile of an Idle or Long-Term Idle Well (or surface owner if different from mineral owner of the actual idle or long-term idle well subject to the notice) may file a notice with the County asking for confirmation of the status that a well is either a Idle or Long Term Idle Well, and the County shall forward this notice to the California *Geologic Energy Management* Division of ~~Oil, Gas and Geothermal Resources~~ to seek information about the status of this well and the owner/permittee for the well. The County shall cooperate with the California *Geologic Energy Management* Division ~~of Oil, Gas and Geothermal Resources~~ in its enforcement of regulations applicable to these wells.

D. The County shall check with the California *Geologic Energy Management* Division ~~of Oil, Gas and Geothermal Resources~~ whether an applicant for an Oil and Gas Conformity Review permit or Conditional Use Permit, in Tier 2 through 5, is the subject of complaint pursuant to California Public Resources Code Section 3235 for an idle well located in Tier 2 through 5, and if so shall coordinate with the California *Geologic Energy Management* ~~Division of Oil, Gas and Geothermal Resources~~ to assure that the applicant is in compliance with applicable idle well regulations for the well(s) included in the complaint(s). An applicant not in compliance with idle well regulations, as determined by official correspondence from the California *Geologic Energy Management* Division ~~of Oil, Gas and Geothermal Resources~~, shall not be eligible to receive additional Oil and Gas Conformity Review permits or conditional use permits under this Chapter until such time as the *California Geologic Energy Management* Division ~~of Oil, Gas and Geothermal Resources~~ has advised the County that the applicant is in compliance or has entered into a written agreement with the California *Geologic Energy Management* Division ~~of Oil, Gas and Geothermal Resources~~ for achieving compliance. The County shall continue to process Oil and Gas Conformity Review permits or conditional use permits under this Chapter for an applicant until such time as the County has received the official correspondence from the *California Geologic Energy Management* Division ~~of Oil, Gas and Geothermal Resources,~~ making its compliance determination regarding the idle well(s) in the compliant(s).

E. The Kern County Planning and ~~Community~~ *Natural Resources* Development Department shall obtain, on an annual basis, a copy of the idle well list from the California *Geologic Energy Management* Division ~~of Oil, Gas and Geothermal Resources.~~

19.98.150 PLUGGED AND ABANDONED

Any permit issued pursuant to this chapter must plug and abandon all permitted wells per the following procedures:

A. *The applicant shall obtain a Minor Activity Review permit for all wells to be plugged and abandoned that were drilled without an Oil and Gas Conformity Review and including all legal non conforming wells.*

B. The applicant shall plug and abandon all facilities in accordance with applicable laws and regulations as administered by the California *Geologic Energy Management* Division ~~of Oil, Gas and Geothermal Resources.~~

C. Within thirty (30) days from completion of the plugged and abandoned procedures for any well constructed *under an Oil and Gas Conformity Review permit* ~~after the amendment of this Chapter 19.98,~~ the applicant shall submit to the ~~Planning and Community Development~~ Department a letter stating which facilities have been abandoned, including the unique well identification number for each well. Compliance of this requirement shall include written confirmation from California *Geologic Energy Management* Division ~~of Oil, Gas and Geothermal Resources~~.

19.98.160 PERMIT REVOCATION AND MODIFICATION

Any permit issued pursuant to this chapter may be revoked or modified pursuant to Section 19.102.020 of this Title.

NOTE: The following text is contained in the current Zoning Ordinance (Title 19), and are shown as ~~strikethrough~~ for proposed replacement with the text above for Chapter 19.98.

~~C H A P T E R 19.98~~

~~OIL AND GAS PRODUCTION~~

~~SECTIONS:~~

~~19.98.010 PURPOSE AND APPLICATION~~
~~19.98.020 UNRESTRICTED DRILLING~~
~~19.98.030 DRILLING BY MINISTERIAL PERMIT~~

~~**19.98.010 PURPOSE AND APPLICATION**~~

~~The purpose of this chapter is to promote the economic recovery of oil, gas, and other hydrocarbon substances in a manner compatible with surrounding land uses and protection of the public health and safety by establishing reasonable limitations, safeguards, and controls on exploration, drilling, and production of hydrocarbon resources. The procedures and standards contained in this chapter shall apply to all exploration drilling and production activities related to oil, gas, and other hydrocarbon substances carried out in unincorporated Kern County.~~

~~**19.98.020 UNRESTRICTED DRILLING**~~

~~No review or permit shall be required for the drilling of any steam injection well, steam drive well, service well, or any well intended for the exploration for or development or production of oil, gas, and other hydrocarbon substances, or for any related accessory equipment, structure, or facility in the Exclusive Agriculture (A), Limited Agriculture (A-1), Medium Industrial (M-2), Heavy Industrial (M-3), or Natural Resource (NR) Districts, provided that:~~

~~A. All drilling installations and operations comply with the requirements of State law and with applicable fire and safety ordinances and regulations of the County of Kern.~~

~~B. Drilling shall not be commenced within one hundred (100) feet of any existing residence without the written consent of the owner thereof.~~

~~C. Signs shall be limited to directional, warning, and identification signs in connection with oil, gas, or other hydrocarbon drilling and development operations.~~

~~D. Disposal of nonhazardous oilfield liquid waste and production water is considered an accessory facility only if the facility complies with the following:~~

~~1. The nonhazardous oilfield liquid waste or production water is produced and disposed of within the same designated oilfield; or~~

~~2. The nonhazardous oilfield liquid waste or production water disposed of outside the designated oilfield of origin is produced by and disposed of solely and only by the same individual, corporation, or entity.~~

~~**19.98.030 DRILLING BY MINISTERIAL PERMIT**~~

~~A. No well for use as an injection well and no well for the exploration for or development or production of oil or gas or other hydrocarbon substances may be drilled, and no related accessory equipment, structure, or facility may be installed in the Light Industrial (M-1) or Recreation-Forestry (RF) District until an application for plot plan review has been submitted to and approved by the Planning Director as consistent with the standards set out in Section 19.98.050 of this chapter and in accordance with the procedures set out in Sections 19.102.040 through 19.102.060 of this title. In approving an application for plot plan review, the Planning Director may waive any standards set out in Section 19.98.050 of this chapter if he/she determines that such waiver will not result in material detriment to the public welfare or to the property of other persons located in the vicinity.~~

~~B. Disposal of nonhazardous oilfield liquid waste and production water is considered an accessory facility only if the facility complies with the following:~~

~~1. The nonhazardous oilfield liquid waste or production water is produced and disposed of within the same designated oilfield; or~~

~~2. The nonhazardous oilfield liquid waste or production water disposed of outside the designated oilfield of origin is produced by and disposed of solely and only by the same individual, corporation, or entity.~~

~~19.98.040 DRILLING BY CONDITIONAL USE PERMIT~~

~~A. No well for use as an injection well and no well for the exploration for or development or production of oil, gas, or other hydrocarbon substances may be drilled, and no related accessory equipment, structure, or facility may be installed in any zoning district described in this title in which such uses are permitted as conditional uses until an application for a conditional use permit has been submitted to and approved by the Planning Commission as consistent with the standards set out in Section 19.98.050 of this chapter and in accordance with the standards and procedures set out in Sections 19.102.130 through 19.102.180 and Chapter 19.104 of this title. In approving a conditional use permit, the Planning Commission may waive any condition set out in Section 19.98.050 of this chapter if it determines that such waiver will not result in material detriment to the public welfare or the property of other persons located in the vicinity.~~

~~B. Disposal of nonhazardous oilfield liquid waste and production water is considered an accessory facility only if the facility complies with the following:~~

~~1. The nonhazardous oilfield liquid waste or production water is produced and disposed of within the same designated oilfield; or~~

~~2. The nonhazardous oilfield liquid waste or production water disposed of outside the designated oilfield of origin is produced by and disposed of solely and only by the same individual, corporation, or entity.~~

~~C. If a producing well or service well is not completed upon land subject to a conditional use permit issued pursuant to this chapter and Chapter 19.104 of this title within twelve~~

~~(12) months from the date of issuance of the permit, or within any extended period thereof, the conditional use permit shall expire and the premises shall be restored as nearly as practicable to their original condition. No permit shall expire while the permittee is continuously conducting drilling, redrilling, completing or abandoning operations, or related operations, in a well on the lands covered by such permit, which operations were commenced while said permit was otherwise in effect. Continuous operations are operations suspended not more than thirty (30) consecutive days. If, at the expiration of the twelve- (12-) month period, the permittee has not completed his drilling program on the lands covered by such permit, the Planning Commission may, upon a written request of the permittee, extend the permit for the additional time requested by permittee for the completion of such drilling program.~~

~~19.98.050 DEVELOPMENT STANDARDS AND CONDITIONS~~

~~All wells drilled, pursuant to Section 19.48.020 of this title and Sections 19.98.030 and 19.98.040 of this chapter, for the exploration for or development or production of oil, gas, and other hydrocarbon substances and related facilities and activities shall comply with the following standards, unless otherwise provided in this chapter:~~

~~A. No oil or gas well shall be drilled within one hundred (100) feet of any public highway or building not necessary to the operation of the well, or within one hundred and fifty (150) feet of any dwelling, or within three hundred (300) feet of any building used as a place of public assembly, institution, or school, or within fifty (50) feet of any building utilized for commercial purposes constructed prior to the commencement of such drilling, without the written consent of the owner of such structure.~~

~~B. All drilling and production activities shall conform to all applicable fire and safety regulations, and firefighting apparatus and supplies required by the Kern County Fire Department shall be maintained on the site at all times during drilling and production operations.~~

~~C. No signs, other than directional and warning signs and those required for identification of the well, shall be constructed, erected, maintained, or placed on the premises or any part thereof, except those required by law or ordinance to be displayed in connection with the drilling or maintenance of the well.~~

~~D. Sanitary toilet and washing facilities, if required by the Kern County Health Department or other governmental agencies, shall be installed and maintained in a clean and sanitary condition during drilling operations, and at such other times as specified by these agencies.~~

~~E. Proven technological improvements generally accepted and used in drilling and production methods shall be employed as they may become available if they are capable of reducing nuisances or annoyances.~~

~~F. All derricks, boilers, and other drilling equipment employed pursuant to this section to drill any well hole or to repair, clean out, deepen, or redrill any completed or drilling well shall be removed within ninety (90) days after completion of production tests following completion of such drilling, or after abandonment of any well, unless such derricks, boilers, and drilling equipment are to be used within a reasonable time, as determined by the Planning Director, for the drilling of another well or wells on the premises.~~

~~G. Within ninety (90) days after any well has been placed in production, or after its abandonment, earthen sumps used in drilling or production or both (unless such sumps are to be used within a reasonable time as determined by the Planning Director for the drilling of another well or wells) shall be filled and the drilling site restored as nearly as practicable to a uniform grade. Temporary earthen sumps may be used for cleanout or remedial work on an existing well or other production facility. However, these sumps shall be filled and the site restored as nearly as practicable to uniform grade within ninety (90) days after the cleanout or other remedial work is completed. Such restoration work shall comply with all applicable regulations of the California Division of Oil and Gas.~~

~~H. Any derrick used for servicing operations shall be of the portable type, provided, however, that upon presentation of proof that the well is of such depth or has such other characteristics, or for other cause, that a portable type derrick will not properly service such well, the Planning Director may approve the use of a standard type of derrick.~~

~~I. Whenever oil or gas is produced into and shipped from tanks located on the premises, such tanks, whenever located within five hundred (500) feet of any dwelling or commercial building, shall be surrounded by shrubs or trees, planted and maintained so as to develop attractive landscaping or shall be fenced in such a manner as to, insofar as practicable, screen such tanks from public view. Such fencing shall comply with the requirements of the California Division of Oil and Gas.~~

~~J. Whenever a well is located within five hundred (500) feet from an existing dwelling unit, except in case of an emergency, no materials, equipment, tools, or pipe used for either drilling or production operations shall be delivered to or removed from the drilling site, except between the hours of eight (8:00) a.m. and eight (8:00) p.m., unless otherwise required by the California Division of Oil and Gas.~~

~~K. Pumping wells shall be operated by electric motors or muffled internal combustion engines.~~

~~L. The height of all pumping units shall not exceed thirty-five (35) feet and shall be painted and kept in neat condition.~~

~~M. All vehicle parking and maneuvering areas shall be treated and maintained with oiled sand or a similar dust binding material.~~

~~N. After production begins and a pump is installed on the wellhead, a fence at least six (6) feet in height shall be installed around the pump site or drilling island for public safety. This fence shall be constructed of chain link with wood or metal slats or other screening fence as may be approved by the Planning Director. This fencing and screening requirement shall apply only to those pump sites located within five hundred (500) feet of any dwelling. Such fencing shall comply with the requirements of the California Division of Oil and Gas.~~

~~O. All required federal, State, and County rules and regulations shall be complied with at all times, including, but not limited to, the rules and regulations of the following agencies:~~

~~1. California Division of Oil and Gas~~

~~2. Kern County Fire Department~~

~~3. Kern County Health Department~~

~~4. Regional Water Quality Control Board~~

~~5. Air Pollution Control District~~

~~6. Kern County Engineering and Survey Services Department~~

~~19.98.060 PLOT PLAN REVIEW — CONDITIONAL USE PERMIT — APPLICATION CONTENTS~~

~~An application for plot plan review pursuant to Section 19.98.030 of this chapter and an application for a conditional use permit pursuant to Section 19.98.040 of this chapter shall include the following:~~

~~A. Name and address of the applicant~~

~~B. Name(s) and address(es) of the property owner(s)~~

~~C. Assessor's parcel number(s)~~

~~D. Legal description of the property~~

~~E. A plot plan or site development plan (in the case of a conditional use permit) drawn at the scale specified by the Planning Director, which includes the following information:~~

~~1. Topography and proposed grading~~

~~2. Location of all proposed well holes and related accessory equipment, structures, and facilities to be installed and any abandoned wells if such are known to exist~~

~~3. Location of all existing dwellings and buildings used for other purposes, located within three hundred (300) feet of the proposed well holes, identification of the use of each structure, and distances between well holes and existing buildings~~

~~4. North arrow~~

~~F. Narrative description of the proposed development, including:~~

~~1. Acreage or square footage of the property~~

~~2. Nature of hydrocarbon development activity~~

~~3. Description of equipment to be used~~

~~4. Distance to all existing buildings~~

~~5. Phasing or development schedule~~

~~19.98.070 PERMIT REVOCATION AND MODIFICATION~~

~~Any permit issued pursuant to this chapter may be revoked or modified pursuant to Section 19.102.020 of this title.~~

REVISIONS TO OTHER SECTIONS OF THE ZONING ORDINANCE (Revisions in Underline and ~~Strikethrough~~)

C H A P T E R 19.48

DRILLING ISLAND (DI) DISTRICT

19.48.080 HEIGHT LIMITS

Height limits in the DI District are as follows:

A. None on derricks and other equipment used during the exploration and drilling phase of development.

B. Pumping units shall not exceed ~~thirty-five (35)~~ eighty (80) feet in height.

19.48.130 SPECIAL REVIEW PROCEDURES AND DEVELOPMENT STANDARDS

A. All drilling and other hydrocarbon development activity in the DI District shall be carried out in accordance with the standards and procedures set out in Section 19.98.~~050~~060 of this title. All activities subject to an Oil and Gas Conformity Review or Minor Activity Review shall comply with the provisions of Section 19.98.060 of the title.

B. Development in the DI District shall comply with the interpretations and provisions of Chapter 19.08 of this title.

CHAPTER 19.81

19.81.050 EXEMPTIONS

The following are permanently exempt from the provisions of this chapter:

1. Outdoor lighting specifically approved in conjunction with a discretionary permit.

2. Federal and State Facilities: Outdoor light fixtures on, in, or in connection with facilities and land owned or operated by the government of the United States of America or the State of California; however, these agencies are encouraged to comply with the provisions of this ordinance.

3. Airports and Other Lighting Required by the Federal Aviation Administration: Outdoor lighting for public and private airports and any other uses that are regulated by the Federal Aviation Administration.

4. Correctional Institutions: Outdoor lighting for federal, State, and County-owned or operated correctional institutions; however, voluntary compliance with the intent and provisions of this chapter is encouraged.

5. Emergency Light: Temporary emergency lighting needed by the sheriff's department, police department, fire department, public utility, rescue operation or in conjunction with any other emergency service.

6. Temporary Construction: All temporary lighting used for the construction or repair of roadways, utilities, and other public infrastructure.

7. Internally Illuminated Signs: All internally illuminated signs, including those used for on-site and off-site advertising purposes. Such signs are regulated by the provisions of Chapter 19.84 (Signs) of the Kern County Zoning Ordinance.

8. Neon, Argon, or Krypton: All fixtures illuminated solely by neon, argon, or krypton.

9. United States Flag and State of California Flag: Lighting used to illuminate a properly displayed United States Flag and/or the State of California Flag.
10. Lighting Required by Building Codes or other Regulations: Communication towers, exit signs, lighting for stairs/ramps, lighting for points of ingress/egress to buildings, and all other illumination required by air navigation safety provisions, building codes, OSHA standards, and other permitting requirements from State or federal agencies.

11. Fossil Fuel Light: All outdoor light fixtures producing light directly by the combustion of fossil fuels (such as kerosene lanterns, gas lamps, etc.)

12. Street Lighting: Lighting equipment within a public or private right-of-way or easement for the principal purpose of illuminating streets, roadways, and/or other areas open to transport by vehicle or pedestrian traffic.

13. Seasonal Displays: Displays using multiple low wattage bulbs or lasers, provided that they do not constitute a fire hazard, create a nuisance, and are maintained in a safe condition. Such displays shall not be illuminated for more than forty-five (45) days per calendar year.

14. Water Features: Lighting in swimming pools and other water features governed by Article 680 of the National Electrical Code.

~~15. Oil and Gas Exploration and Production: Outdoor lighting in association with oil and gas exploration and production operations and related facilities shall be exempt from this chapter and are regulated by the provisions of Chapter 19.98 of the Kern County Zoning Ordinance.~~

~~16.~~ 15. Temporary Event Lighting: Temporary lighting for special events that does not conform to this chapter shall be reviewed as part of an application for a Temporary Event Permit (TEP), pursuant to Chapter 19.08.340 of the Kern County Zoning Ordinance. Any temporary lighting exemption approved via the TEP process shall be utilized for a period of time that exceeds a combined total of twelve (12) combined days on any one (1) parcel during a calendar year. Exemptions are renewable for a period of not more than twelve (12) additional combined days. Requests for renewal of a temporary exemption shall be processed in the same manner as the original request. No outdoor light fixtures shall be exempted from this chapter for more than twenty-four (24) days combined during a calendar year.

~~17.~~ 16. Steeples: Lighting used to illumination the tall ornamental tower that forms the superstructure of a church, temple, office building, etc., shall be exempt from this chapter.

~~18.~~ 17. Temporary Agricultural Activities: Lighting used to illuminate temporary agricultural activities such as harvesting on property zoned A (Exclusive Agriculture) or A-1 (Limited Agriculture) and lasting no more than twelve (12) consecutive days and no more than twenty four (24) combined days on any one parcel during a calendar year.

C H A P T E R 19.50

FLOODPLAIN PRIMARY (FPP) DISTRICT

19.50.130 SPECIAL REVIEW PROCEDURES AND DEVELOPMENT STANDARDS

A. All development within the FPP District is subject to the requirements of the Flood Damage Prevention Ordinance, Chapter 17.48 of this code.

B. Development in the FPP District shall comply with the interpretations and provisions of Chapter 19.08 of this title.

C. Oil or gas exploration and production shall comply with Section 19.98.~~050~~060 and the following standards:

1. The following uses are permitted within the FPP District if they will not obstruct flows, will not cause peripheral flooding of other properties, will not cause any increase in flood levels during the occurrence of the base flood discharge, will be resistant to floatation and immune to extensive damage by flooding, and will not endanger life or property:

   (a) All oil or gas wells, including pumps and all other associated equipment.

   (b) Feasible remedial work, improvements, and flood-proofing of facilities.

2. No oil or gas well shall be drilled on the slope or within ten (10) feet of the top or toe of the bank of a river or stream located within the FPP District. The required setback on the top of bank shall be measured from an imaginary plane on a slope two (2) horizontal to one (1) vertical projected upward from the toe of the existing bank.

3. All oil or gas wells in the FPP District, including pumps and all other associated equipment, shall be designed such that they are resistant to damage by flooding.

4. All pipelines in the FPP District shall be flood-proofed by burial to sufficient depth to prevent rupture during flood conditions or by suspension at least two (2) feet above the surface of the base flood. Supports for elevated pipelines shall also carry a catwalk to facilitate removal of debris caught by supports during floods.

5. The location of all buried pipelines shall be recorded on appropriate maps by the company that owns said pipelines, and the maps shall be made available to any public agency that shall request a copy.

6. All drilling, redrilling, and producing, including remedial work, well pulling, work-overs, and deepening, shall conform to all applicable fire, safety, spacing, and environmental State law and regulations.

7. Proven technological improvements generally accepted and used in drilling and production methods shall be adopted as they may from time to time become available, if capable of reducing factors of nuisance and annoyance.

8. Prior to the commencement of any drilling, a copy of a Spill Prevention Control and Countermeasure Plan, as required by the United States Environmental Protection Agency, shall be filed with the Kern County ~~Engineering and Survey Services~~ Public Works Department.

9. All pumps expected to be inaccessible during times of flood shall be equipped with an accessible remote switch to shut off the pumps during emergencies.

10. The derrick, all boilers, and all other drilling equipment used pursuant to this chapter to drill any well hole or to repair, clean out, deepen, or redrill any completed or drilling well shall be removed within ninety (90) days after completion of production tests following completion of such drilling, or after abandonment of any well, unless such derrick, boilers, and drilling equipment are to be used within a reasonable time limit, determined by the Kern County ~~Engineering and Survey Services~~ Public Works Department, for the drilling of another well or wells on the premises.

11. After any well has been placed in production, no earthen sumps shall be used for the storage of petroleum or gas.

12. Within ninety (90) days after any well has been placed in production or after its abandonment, earthen sumps used in drilling or production or both shall be emptied by vacuum truck or other approved means, then filled, and the drilling site restored as nearly as practicable to a uniform grade, unless such sumps are to be used within a reasonable time limit, as determined by the Kern County ~~Engineering and Survey Services~~ Public Works Department.

13. Any derrick used for servicing operations shall be of the portable type; provided, however, that upon presentation of proof that the well is of such depth or has such other characteristics, or for other cause, that a portable-type derrick will not properly service such well, the Kern County ~~Engineering and Survey Services~~ Public Works Department may approve the use of a standard type of derrick.

14. Directional and warning signs, and those required for identification of the well, shall be constructed, erected, placed, or maintained on the premises, except those required by law to be displayed in connection with the drilling or maintenance of the well.

15. If a producing or service well is not secured twelve (12) months from the date of commencement of drilling operations or any extended period granted by the Kern County ~~Engineering and Survey Services~~ Public Works Department, the premises shall be restored to the original condition as nearly as practicable to do so. If at the expiration of the twelve- (12-) month period, the drilling program has not been completed, the Kern County ~~Engineering and Survey Services~~ Public Works Department may, upon a written request, grant an additional period of time as requested for the completion of such drilling program.

C H A P T E R 19.66

PETROLEUM EXTRACTION (PE) COMBINING DISTRICT

19.66.020 PERMITTED USES

The following uses and all others determined to be similar to these uses pursuant to Sections 19.08.030 through 19.08.080 of this title are permitted in a PE District:

A. Wells for the exploration for and development and production of oil or gas or other hydrocarbon substances if the well or wells are located more than ~~three~~two hundred and ten (~~300~~210) feet away from any existing dwelling or existing building utilized for commercial purposes, excluding those premises utilized solely for storage of equipment, material, household goods, or similar material.

B. Deepening or redrilling, within the existing well bore, of any well used for the production or development of oil or gas or other hydrocarbon substances, or the replacement of any production facility which did not require a conditional use permit on the date drilling began or the date the facility was installed.

C. Drilling of a replacement well when the original well did not require a conditional use permit, and where the original well has been abandoned in accordance with California Division of Oil and Gas regulations and drilling of a replacement well commences within one (1) year of the conclusion of abandonment procedures, and the replacement well is located within twenty (20) feet of the original well or is farther from any existing dwelling or commercial building than the original well.

D. Uses permitted by the base district with which the PE District is combined.

19.66.030 USES PERMITTED BY A CONDITIONAL USE PERMIT

The following uses and all others determined to be similar to these uses pursuant to Sections 19.08.030 through 19.08.080 of this title are permitted in a PE District subject to securing a conditional use permit in accordance with the procedures set out in Chapter 19.104 of this title:

A. Wells for the exploration for and development and production of oil or gas or other hydrocarbon substances if the well or wells are located within ~~three~~two hundred and ten (~~300~~210) feet of any existing dwelling or existing building utilized for commercial purposes, excluding those premises utilized solely for storage of equipment, material, household goods, or similar material.

B. Conditional uses permitted by the base district with which the PE District is combined.

19.66.080 HEIGHT LIMITS

Height limit requirements in a PE District are as follows:

A. No height limit on derricks and other equipment used during the exploration and drilling phase of development.

B. Pumping units shall not exceed ~~thirty-five (35)~~ eighty (80) feet in height.

C. All other uses permitted by the base district shall conform to the height limits of the base district with which the PE District is combined.

19.66.130 SPECIAL REVIEW PROCEDURES AND DEVELOPMENT STANDARDS

All drilling and hydrocarbon development activities in a PE District shall be carried out in accordance with the standards and procedures set out in Section 19.98.~~050~~060 of this title. All activities subject to an Oil and Gas Conformity Review or Minor Activity Review shall comply with the provisions of Section 19.98.060 of the title.

CHAPTER 19.102

PERMIT PROCEDURES
ARTICLE II. MINISTERIAL PERMITS ISSUED BY THE PLANNING DIRECTOR

19.102.040 GENERAL REQUIREMENTS — PERMIT TYPES

The ministerial permits specified in this title for review pursuant to this article shall be issued by the Planning Director upon submission of an application containing the information specified in applicable sections of this title and a determination by the Planning Director that the proposed use or development meets the development standards and conditions specified in the applicable section or sections of this title. These permits include:

A. CRV recycling center permit (Section 19.08.480)

B. Temporary animal permit plot plan review (Sections 19.14.130 and 19.60.130 through 19.60.160)

C. Extensions for temporary mobilehomes and recreational vehicles (Sections 19.16.130 and 19.18.160)

D. Mobilehome park plot plan review (Sections 19.26.130 through 19.26.190)

E. Minor plan modifications (Section 19.52.130 through 19.52.180, 19.56.130 through 19.52.180, 19.56.130 through 19.56.200, 19.58.130 through 19.58.180, and 19.100.050

F. Commercial wind farm plot plan review (Section 19.64.130 through 19.64.150)

G. Geologic hazard plot plan review (Section 19.68.130 through 19.68.150)

H. Special development standards plot plan review (Sections 19.80.040 through 19.80.070)

I. Off-street parking plot plan review not in conjunction with a ministerial permit (Sections 19.82.100 through 19.82.130)

J. Landscaping plot plan review not in conjunction with a ministerial permit (Sections 19.86.070 through 19.86.100)

K. Density bonus permit (Sections 19.92.030 through 19.92.060)

L. Home occupation permit (Sections 19.94.050 through 19.94.080)

M. Production water injection wells for the purpose of disposing of production wastewater produced in the same oilfield in which the injection well is located (Section 19.98.030)

N. ~~Oil and gas plot plan review (Section 19.98.030)~~ Oil and Gas Conformity Review and Minor Activity Review (Section 19.98.070 through 19.98.120)

O. Large family day-care permit - no hearing (Sections 19.96.030 through 19.96.060)

P. Temporary batch plant (thirty (30) days or less) plot plan review (Section 19.08.290)

Q. Secondary residential unit plot plan review (Section 19.90.040 through 19.90.060)

R. Truck parking as accessory to residential use permit (Section 19.08.252)

C H A P T E R 19.108

NONCONFORMING USES, STRUCTURES, AND LOTS

19.108.040 NONCONFORMING USES OF LAND

A. A nonconforming use of land shall not be expanded, extended, or intensified in any way with respect to scope, duration, or frequency of the use, except as follows:

The Planning Commission may authorize the expansion or intensification of legal, nonconforming uses if, after consideration at a public hearing noticed pursuant to Section 19.102.150, both of the following findings can be made:

1. The proposed expansion will not create any significant adverse impacts to surrounding properties.

2. The only other remedy to bring the use into conformance would require an amendment to the applicable General Plan.

Public hearing notification shall consist of mailing notices to property owners having property within three hundred (300) feet from the exterior boundaries of the subject property. Published notice in a local newspaper shall not be required, unless the Planning Director determines that such additional notice is warranted. In consideration of a request to expand or intensify a legal, nonconforming use, the terms and conditions for any approval shall be as specified in Section 19.104.050.

B. A nonconforming use of land shall not be changed to or replaced by any other use except a use that complies with the regulations of the zoning district in which the subject property lies.

C. Any nonconforming use of land that has been discontinued or abandoned for a period of one (1) year or more shall not be reestablished. In instances where the assessed value of improvements on the property exceeds fifty thousand dollars ($50,000), as determined by the County Assessor, the nonconforming use shall not be reestablished if the use has been discontinued or abandoned for a period of two (2) years or more.

D. The exploration for or development or production of oil, gas, or other hydrocarbon substances ~~shall not be considered nonconforming uses of land~~ lawfully constructed prior to MONTH XXX, DAY XXX, YEARXX shall be considered nonconforming uses of land. Any subsequent ~~,~~ maintenance, production, operations, well stimulation treatments, alterations or expansion, and other activities involving existing wells, including ancillary facilities, are allowed subject to Chapter 19.98 of this Title.

E. A legal nonconforming dwelling in any zone district may be replaced with the approval of the Planning Director, provided that all applicable requirements of this title, other than density or conditional use permit requirements, can be satisfied.

F. Any use of land continuously in existence for a period of twenty (20) years or more may qualify as a legal, nonconforming use pursuant to Section 19.108.080, irrespective of when zoning requirements became effective for that property, provided that the Planning Director determines that the use is not significantly incompatible with surrounding land uses and that there is no significant threat to the public health, safety, and welfare in allowing the use to continue.

19.108.060 NONCONFORMING SETBACKS

Any use permitted under the provisions of this title that currently exists with nonconforming setbacks may:

1. ~~b~~Be replaced in the same location if damaged or destroyed by fire, earthquake, explosion, or act of God regardless of the cost of such reconstruction; or
2. Be maintained in accordance with the provisions of this Title provided there is no greater degree of nonconformity with regard to setback.

C H A P T E R 19.08

INTERPRETATIONS AND GENERAL STANDARDS

SECTIONS:

~~19.08.230 PRIVATE OIL PIPELINES AND RELATED FACILITIES — COUNTY REVIEW~~

~~The provisions of this title shall not be construed to apply to the construction, installation, operation, and maintenance of pipelines for the transmission of crude oil or natural gas operated by private enterprises; provided, however, before any right-of-way for transmission lines is acquired for regional or interstate facilities, the proposed route shall be submitted for the Planning Director review and recommendation.~~

<u>19.08.230 REGIONAL OR INTERSTATE TRANSMISSION PIPELINE FACILITIES — COUNTY REVIEW</u>

<u>Before any right-of-way for transmission lines is acquired for regional or interstate facilities, the proposed route shall be submitted for the Planning Director review and recommendation.</u>

~~19.08.260 OIL AND GAS EXPLORATION BY SCIENTIFIC MEANS~~

~~The provisions of this title shall not be construed to apply to the exploration for oil and gas by scientific means.~~

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C H A P T E R 19.26

MOBILEHOME PARK (MP) DISTRICT

19.26.030 USES PERMITTED WITH A CONDITIONAL USE PERMIT

The following uses are permitted in the MP District with a conditional use permit:

A. RECREATION, ENTERTAINMENT, AND TOURIST FACILITIES

— Recreational vehicle park, except as permitted by Subsection 19.26.020.B

B. MISCELLANEOUS USES

— Drainage sump
— Water system, large

— Water treatment plant

C. RESOURCE EXTRACTION AND ENERGY DEVELOPMENT USES

— Oil or gas exploration and production pursuant to Chapter 19.98 of this title

C H A P T E R 19.12

EXCLUSIVE AGRICULTURE (A) DISTRICT

19.12.020 PERMITTED USES

E. RESOURCE EXTRACTION AND ENERGY DEVELOPMENT USES

— ~~Cogeneration facility or steam generators, primarily intended for steam production used for production of oil or gas, excluding coal fired~~

— Electrical power generating plant in conjunction with a biogas recovery system associated with a confined animal facility, subject to the criteria specified in Section 19.12.130.G

— Explosives storage, temporary

— Mineral exploration

— Oil or gas exploration and production pursuant to Chapter 19.98 of this title

— Solar energy electrical generators which are accessory to a permitted or conditionally permitted use and where the power generated does not exceed the total on-site power demand

— Small wind energy system, pursuant to Section 19.08.415, except when all criteria specified below for wind-driven electrical generators will be satisfied , in which case a small wind energy system permit pursuant to Section 19.08.415 shall not be required

— Wind-driven electrical generators when accessory to a permitted or conditionally permitted use where:

1. The system employed is designed to supplement other electricity sources, or as an accessory use to existing buildings or facilities, wherein the power generated is used primarily for on-site consumption.

2. The wind generators are located a minimum distance of one times (1x) the overall machine height from any property line.

3. The parcel on which the wind generators will be erected does not abut a residential zoning district.

4. The wind generator(s) will be located a minimum of one and one-half (1 1/2) times the overall height to any off-site dwelling.
5. The proposed height of the wind turbines does not exceed the maximum heights specified in Figure 19.08.160.

19.12.030 USES PERMITTED WITH A CONDITIONAL USE PERMIT

G. RESOURCE EXTRACTION AND ENERGY DEVELOPMENT USES

— Backfilling of surface mines with inert, nonorganic fill material, limited to construction and demolition wastes, where a Solid Waste Facility Permit is not required

— ~~Coal-fired~~ ~~c~~Cogeneration facility or steam generators, primarily intended for production of oil or gas

— Concrete or asphalt batch plant

— Dam, small hydro

— Dam, large hydro

— Electrical power generating plant

— Explosives storage, permanent

— Mining and mineral extraction pursuant to Chapter 19.100 of this title

— Rock, gravel, sand, concrete, aggregate, or soils crushing, processing, or distribution

— Solar energy electrical generators when not accessory to a permitted or conditionally permitted use

— Wind-driven electrical generators when accessory to a permitted or conditionally permitted use which do not comply with the installation standards specified in Section 19.12.020.E.

C H A P T E R 19.14

LIMITED AGRICULTURE (A-1) DISTRICT

19.14.020 PERMITTED USES

E. RESOURCE EXTRACTION AND ENERGY DEVELOPMENT USES

~~— Cogeneration facility or steam generators, primarily intended for steam production, used for production of oil and gas, excluding coal fired~~

— Mineral exploration

— Oil or gas exploration and production pursuant to Chapter 19.98 of this title, including the temporary installation of commercial coaches as accessory to this activity, not to exceed a two- (2-) year period

- Solar energy electrical generator which are accessory to a permitted or conditionally permitted use and where the power generated does not exceed the total on-site power demand

- Small wind energy system, pursuant to Section 19.08.415

19.14.030 USES PERMITTED WITH A CONDITIONAL USE PERMIT

G. RESOURCE EXTRACTION AND ENERGY DEVELOPMENT USES

- ~~Coal-fired~~ ~~c~~<u>C</u>ogeneration facility or steam generators, primarily intended for production of oil or gas

- Concrete or asphalt batch plant, temporary

- Electrical power generating plant, excluding nuclear or coal powered

- Mining and mineral extraction pursuant to Chapter 19.100 of this title

- Solar energy electrical generators when not accessory to a permitted or conditionally permitted use

- Wind-driven electrical generators, commercial

C H A P T E R 19.38

MEDIUM INDUSTRIAL (M-2) DISTRICT

19.38.020 PERMITTED USES

H. RESOURCE EXTRACTION AND ENERGY DEVELOPMENT USES

- Cogeneration facility or steam generators, <u>not primarily intended for production oil or gas,</u> excluding coal fired

- Electrical power generating plant, excluding nuclear or coal

- Mineral exploration

- Oil or gas exploration and production pursuant to Chapter 19.98 of this title

- Solar energy electrical generators which are accessory to a permitted or conditionally permitted use and where the power generated does not exceed the total on-site power demand

— Small wind energy system, pursuant to Section 19.08.415

19.38.030 USES PERMITTED WITH A CONDITIONAL USE PERMIT

G. RESOURCE EXTRACTION AND ENERGY DEVELOPMENT USES

— ~~Coal-fired~~ ~~c~~Cogeneration facility or steam generators

— Mining and mineral extraction pursuant to Chapter 19.100 of this title

— Ore reduction

— Potash manufacture

— Rock, gravel, sand, concrete, aggregate, or soils crushing, processing, or distribution

— Solar energy electrical generators when not accessory to a permitted or conditionally permitted use

— Wind generators, commercial

C H A P T E R 19.40

HEAVY INDUSTRIAL (M-3) DISTRICT

19.40.020 PERMITTED USES

H. RESOURCE EXTRACTION AND ENERGY DEVELOPMENT USES

— Cogeneration facility or steam generators, not primarily intended for production oil or gas, excluding coal fired

— Electrical distribution stations

— Electrical power generating plants, excluding nuclear and coal

— Mineral exploration

— Oil or gas exploration and production pursuant to Chapter 19.98 of this title

— Rock, gravel, sand, concrete, aggregate, or soils crushing, processing, or distribution

— Solar energy electrical generators which are accessory to a permitted or conditionally permitted use and where the power generated does not exceed the total on-site power demand

— Small wind energy system, pursuant to Section 19.08.415

— Wind-driven electrical generators when accessory to a permitted or conditionally permitted use where:

1. The annual amount of power generated does not exceed the total on-site annual power demand.

2. The wind generators are located a minimum distance of one (1) times the overall machine height from any property line.

3. The parcel on which the wind generators will be erected does not abut a residential zoning district.

4. The wind generator(s) will be located a minimum of one (1) times the overall height to any off-site dwelling.

5. The proposed height of the wind turbines does not exceed the maximum heights specified in Figure 19.08.160.

19.40.030 USES PERMITTED WITH A CONDITIONAL USE PERMIT

G. RESOURCE EXTRACTION AND ENERGY DEVELOPMENT USES

— ~~Coal-fired~~ ~~c~~Cogeneration facility or steam generators

— Electrical power generating plant, nuclear or coal powered

— Mining and mineral extraction pursuant to Chapter 19.100 of this title

— Solar energy electrical generators when not accessory to a permitted or conditionally permitted use

— Wind-driven electrical generators, commercial

— Wind-driven electrical generators when accessory to a permitted or conditionally permitted use which do not comply with the installation standards specified in Section 19.12.020.E.

C H A P T E R 19.46

NATURAL RESOURCE (NR) DISTRICT

19.46.020 PERMITTED USES

E. RESOURCE EXTRACTION AND ENERGY DEVELOPMENT USES

— Accessory structures and equipment storage for natural resource extraction or processing uses

~~— Cogeneration facility or steam generators, primarily intended for steam production for another permitted use, excluding coal-fired~~

— Explosives storage, temporary, subject to approval by the Kern County Fire Department

— Mineral exploration

— Oil or gas exploration and production pursuant to Chapter 19.98 of this title

— Solar energy electrical generators which are accessory to a permitted or conditionally permitted use and where the power generated does not exceed the total on-site power demand

— Small wind energy system, pursuant to Section 19.08.415

19.46.030 USES PERMITTED WITH A CONDITIONAL USE PERMIT

G. RESOURCE EXTRACTION AND ENERGY DEVELOPMENT USES

— ~~Coal-fired~~ ~~c~~Cogeneration facility or steam generators

— Concrete or asphalt batch plant

— Electric power generating plant

— Explosives storage

— Mining and mineral extraction pursuant to Chapter 19.100 of this title

— Rock, gravel, sand, concrete, aggregate, or soils crushing, processing, or distribution

— Solar energy electrical generators when not accessory to a permitted or conditionally permitted use

— Wind-driven electrical generators, commercial or domestic

C H A P T E R 19.44

OPEN SPACE (OS) DISTRICT

19.44.030 USES PERMITTED WITH A CONDITIONAL USE PERMIT

The following uses and all others determined to be similar to these uses pursuant to Sections 19.08.030 through 19.08.080 of this title are all permitted in the OS District subject to securing a conditional use permit in accordance with the standards and procedures set out in Chapter 19.104 of this title:

A. RECREATION, ENTERTAINMENT, AND TOURIST FACILITIES

— Park

— Roads or trails for motor driven vehicles, excluding race courses

B. INSTITUTIONAL USES

— Public service uses

C. TRANSPORTATION FACILITIES

— Auto parking lot

D. RESOURCE EXTRACTION AND ENERGY DEVELOPMENT USES

— Oil or gas exploration and production pursuant to Chapter 19.98 of this title

~~D~~E. MISCELLANEOUS USES

— Restrooms and shelters

— Scientific study sites for the systematic exploration and classification of archaeological, anthropological, or historic artifacts or remains

Chapter 4
Environmental Setting, Impacts, and Mitigation Measures

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Chapter 4
Environmental Setting, Impacts, and Mitigation Measures

4.1 Introduction

The public process for this project has resulted in two draft SREIRs that have been prepared and circulated for public comment. The first draft SREIR was completed in August 2020 and is referred to as the SREIR (August 2020), and this second draft SREIR has been released in October 2020 and is referred to as the SREIR (October 2020). This SREIR (October 2020) shows all text changes from the earlier SREIR (August 2020) as italics, with text additions underlined and text deletions as strikeouts. Unless otherwise noted, all references to the SREIR refer to this SREIR (October 2020).

The purpose of the Supplemental Recirculated Environmental Impact Report (SREIR) is to provide the analysis required to address the California Environmental Quality Act (CEQA) deficiencies in the Project's 2015 Final Environmental Impact Report (FEIR) that were identified in the Appellate Court opinion issued on February 25, 2020, and reconsideration of the Zoning Ordinance revisions for local oil and gas permitting. That decision held that the certified Environmental Impact Report (EIR) was adequate except for "five areas in which the EIR did not comply with CEQA: (1) mitigation of water supply impacts; (2) impacts from PM2.5 emissions; (3) mitigation of conversion of agricultural land; (4) noise impacts; and (5) recirculation of the Multi-Well Health Risk Assessment for public review and comment." The opinion set aside the previously approved Kern County Zoning Ordinance (Ordinance) amendments and the certification of the 2015 FEIR. The opinion further directs the County, "in the event it decides to present the Ordinance (in its present or a modified form) to the Board for approval, to correct the CEQA violations identified in this opinion," to prepare "a revised EIR correcting the CEQA violations," and to prepare and publish "responses to the comments received before certifying the revised EIR and reapproving the Ordinance."

This SREIR is a supplemental analysis of the CEQA deficiencies in five topical resource sections of this chapter: Section 4.2, Agriculture and Forest Service; Section 4.3, Air Quality; Section 4.8, Hydrology and Water Quality; Section 4.12, Noise; and Section 4.17, Utilities and Service Systems. This numbering corresponds to the named chapters in the 2015 FEIR (SREIR Volume 3) and provides for reference to other analysis that the court found legally valid.

The 2015 adopted Ordinance has been implemented by Kern County as the Lead Agency through the Kern County Planning and Natural Resources Department Oil and Gas Permitting program (December 9, 2015, to March 25, 2020), and this implemented permit system is described in Section 1.3, Project History, and in Chapter 3.4.1, Proposed Project/Proposed Zoning Code Amendment. As described in Chapter 3.0, Project Description, the Project includes minor administrative changes to the 2015 Ordinance, and clarifications for some of the mitigation measures to further improve the ministerial permit process. These clarifications are informed by the County's implementation experience to ensure applicant compliance and informed by the adopted process and online permit system, as well as administrative materials prepared by the County to provide guidance and direction to the applicants on submitting applications and implementing mitigation measures.

As described in Section 3.1.1, Revisions to Title 19 - Kern County Zoning Ordinance (2020 A) and Related Changes, the changes to the 2015 Ordinance are (1) updates to names of County departments and State agencies that have changed since 2015, reference to this SREIR, and implementation details; (2) clarification of the process for monitoring Split Estate 120-day process; and (3) adjustments to Tier Maps for technical geographic information system (GIS) errors identified from 2015 adoption.

The Ordinance also requires implementation of the mitigation measures from the 2015 FEIR. Some of these mitigation measures have been modified based on this SREIR analyses and are further described in Sections 4.2, Agriculture and Forest Service; 4.3, Air Quality; 4.9, Hydrology and Water Quality; 4.12, Noise; and 4.17, Utilities and Service Systems. In addition, a comprehensive review has been completed of all mitigation measures from the 2015 FEIR to identify clarifications that should be made in identified mitigation measures for minor word modifications. All applicable mitigation measures for those sections, including those with clarifying word modifications, are included in this section.

Clarifying word modifications made as part of this comprehensive evaluation for mitigation measures for other topical 2015 FEIR resource sections are identified in the Section 4.18, Supplemental Analysis. Clarifying word modifications are shown in strikethrough and underline with replacement wording for reading purposes. The recommended clarified mitigation measures are also shown in final form. As the name of County departments and state agencies have changed since 2015, these changes will be automatically made for mitigation measures that have no other changes. The complete analysis of the impact and the Section 4.18 mitigation measures are contained in the 2015 FEIR sections for each topical area, provided in SREIR Volume 3.

Section 4.2

Agricultural and Forest Resources

Section 4.2
Agricultural and Forest Resources

4.2.1 Introduction: Purpose/Scope

This section of the Supplemental *Recirculated* Environmental Impact Report (*October 2020)* (SREIR) describes the affected environment and regulatory setting for agricultural and forestry resources. This section also describes the impacts to agricultural and forestry resources, including rangeland/grazing land, that would result from implementation of the Amendment to Chapter 19.98 (Oil and Gas Production) and related ordinance amendments to the Kern County Zoning Ordinance, and future development of oil and gas resources pursuant to the Amended Ordinance (herein referred to as the "Project"), and mitigation measures that would reduce these impacts, if necessary. *Except where specifically noted, all underlined and italicized text indicates additions, and italicized strikethrough text indicates deletions from the SREIR (August 2020). Non-italicized underlined and strikethrough text is the same as in the SREIR (August 2020).*

This section is based on the Farmland Conversion Study California Environmental Quality Act (CEQA) Analysis prepared by Ecology and Environment, Inc., and presented in Appendix H of the 2015 Final FEIR (SREIR Volume 4).

4.2.2 Environmental Setting

Kern County is California's third largest county, encompassing 8,202 square miles at the southern end of the Central Valley. The 3,700-square-mile Project Area is predominantly located in the western portion of the County in the San Joaquin Valley bounded by Kings and Tulare Counties to the north, Santa Barbara and San Luis Obispo Counties to the west, the Tehachapi Mountains and the Sierra Nevada Mountains to east, and the northern boundary of the Los Padres National Forest to the south.

Regional

Kern County has a long history of agricultural operations and contains approximately 1,373 square miles of harvested agricultural land and 2,317 square miles of range land. Agriculture in Kern County makes a significant contribution to the economy of the state. As discussed in the 2015 FEIR, in 2012, agriculture in Kern County accounted for a gross value of $6.2 billion (Table 4.2-1).

Table 4.2-1: Agricultural Product Values for Kern County in 2012

Product	Total Value
Fruit and Nut Crops	$3,650,049,000
Seed Crops	$7,742,000
Field Crops	$539,370,000

Table 4.2-1: Agricultural Product Values for Kern County in 2012

Product	Total Value
Vegetable Crops	$714,490,000
Nursery Crops	$100,824,100
Industrial and Wood Crops	$15,717,000
Livestock and Poultry	$395,078,000
Livestock and Poultry Products	$732,385,000
Apiary Products	$56,707,000
TOTAL	$6,212,362,100

As shown in Table 4.2-2, by 2018, agriculture in Kern County accounted for a total gross value of $6.6 billion (adjusted for inflation), with some up-and-down fluctuations of total gross value in the years since 2012.

Table 4.2-2: Agricultural Product Values for Kern County - 2013 through 2018 (Not Adjusted for Inflation)

Product	2013 Value [a]	2014 Value [b]	2015 Value [c]	2016 Value [d]	2017 Value [e]	2018 Value [f]
Fruit and Nut Crops	$4,133,389,000	$4,769,213,000	$4,593,866,000	$4,900,990,000	$4,802,164,000	$5,147,712,000
Seed Crops	$5,305,000	$6,591,000	$11,251,000	$9,410,450	$14,932,000	$7,876,000
Field Crops	$522,365,000	$507,302,000	$340,618,000	$304,712,000	$303,075,000	$331,573,000
Vegetable Crops	$686,789,000	$648,857,000	$654,165,000	$836,670,000	$916,636,000	$770,301,000
Nursery Crops	$111,270,590	$93,719,690	$83,264,690	$102,317,890	$113,705,000	$122,473,000
Industrial and Wood Crops	$14,176,000	$18,498,000	$12,838,000	$9,045,000	$10,764,000	$14,925,000
Livestock and Poultry	$418,926,000	$443,650,000	$370,376,000	$326,508,000	$332,978,000	$272,181,000
Livestock and Poultry Products	$819,880,000	$980,756,000	$652,917,000	$609,513,000	$666,421,000	$687,292,000
Apiary Products	$57,755,000	$83,737,000	$82,772,000	$88,778,000	$93,493,000	$111,819,000
Total:	**$6,769,855,590**	**$7,552,343,690**	**$6,802,067,690**	**$7,187,944,340**	**$7,254,168,000**	**$7,466,152,000**
Agricultural Product Values for Kern County - 2013 through 2018 (Adjusted for Inflation)						
Fruit and Nut Crops	$4,133,389,000	$4,683,308,824	$4,445,874,426	$4,638,378,346	$4,415,161,499	$4,564,256,785
Seed Crops	$5,305,000	$6,472,281	$10,888,549	$8,906,206	$13,728,642	$6,983,313
Field Crops	$522,365,000	$498,164,358	$329,644,978	$288,384,498	$278,650,432	$293,991,644
Vegetable Crops	$686,789,000	$637,169,637	$633,091,049	$791,838,386	$842,765,048	$682,993,059
Nursery Crops	$111,270,590	$92,031,589	$80,582,315	$96,835,351	$104,541,606	$108,591,588

Table 4.2-2: Agricultural Product Values for Kern County - 2013 through 2018 (Not Adjusted for Inflation)

Product	2013 Value [a]	2014 Value [b]	2015 Value [c]	2016 Value [d]	2017 Value [e]	2018 Value [f]
Industrial and Wood Crops	$14,176,000	$18,164,810	$12,424,423	$8,560,338	$9,896,538	$13,233,361
Livestock and Poultry	$418,926,000	$435,658,873	$358,444,323	$309,012,595	$306,143,573	$241,331,290
Livestock and Poultry Products	$819,880,000	$963,090,394	$631,883,253	$576,853,228	$612,714,672	$609,392,517
Apiary Products	$57,755,000	$82,228,710	$80,105,497	$84,020,974	$85,958,475	$99,145,140
Total:	**$6,769,855,590**	**$7,416,309,115**	**$6,582,938,812**	**$6,802,789,921**	**$6,669,560,485**	**$6,619,918,699**

Sources:
[a] Kern County Department of Agriculture and Measurement Standards 2013
[b] Kern County Department of Agriculture and Measurement Standards 2014
[c] Kern County Department of Agriculture and Measurement Standards 2015
[d] Kern County Department of Agriculture and Measurement Standards 2016
[e] Kern County Department of Agriculture and Measurement Standards 2017
[f] Kern County Department of Agriculture and Measurement Standards 2018

As shown in Table 4.2-3, harvested crop acreage totals for Kern County have remained relatively constant between 2012 and 2018, with some up and down fluctuation on a year-to-year basis.

Table 4.2-3: Harvested Crop Acreage Totals for Kern County - 2013 through 2018

Product	2012 [a] Acres	2013 [b] Acres	2014 [c] Acres	2015 [d] Acres	2016 [e] Acres	2017 [f] Acres	2018 [g] Acres
Fruit and Nut Crops	411,749	422,146	510,308	525,398	530,238	546,290	551,495
Seed Crops	2,590	1,550	1,500	1,390	1,150	1,200	795
Field Crops	381,856	339,746	298,843	286,010	271,303	248,021	236,831
Vegetable Crops	79,428	73,550	66,450	66,170	81,578	86,830	74,160
Nursery Crops	3,008	2,087	3,356	2,087	1,688	2,230	2,532
Total:	**878,631**	**839,079**	**880,457**	**881,055**	**885,957**	**884,571**	**865,813**

Sources:
[a] Kern County Department of Agriculture and Measurement Standards 2013
[b] Kern County Department of Agriculture and Measurement Standards 2014
[c] Kern County Department of Agriculture and Measurement Standards 2015
[d] Kern County Department of Agriculture and Measurement Standards 2016
[e] Kern County Department of Agriculture and Measurement Standards 2017
[f] Kern County Department of Agriculture and Measurement Standards 2018

In the future, constraints on groundwater use resulting from the Sustainable Groundwater Management Act (SGMA) process could affect agricultural activity in Kern County, as discussed in Chapter 4.17, Utilities and Service Systems. For example, some water districts are acquiring lands to intentionally fallow agricultural land to reduce groundwater demand. The baseline data from the 2015 FEIR and 2018 SEIR accordingly represent a conservative baseline for purposes of agricultural impact analysis. _The conservative nature of this baseline is further supported by a 2019 paper suggesting that "even with ambitious investments in new supplies, to end overdraft the irrigated footprint of the valley may need to shrink by more than 500,000 acres by the early 2040s" (Hanak et al. 2019). However, at this early stage of SGMA implementation, it is not possible to provide reliable, non-speculative projections of changed patterns of agricultural land use. Therefore, the agricultural baseline has not been updated in this SREIR._

According to the U.S. Department of Agriculture (USDA) 2012 Census of Agriculture, in Kern County in 2012, the average farm size was 1,202 acres (USDA 2012). By 2017, the average farm size in Kern County had increased to 1,326 acres and net cash farm income had increased by 28% since 2012 (USDA 2017).

The top agricultural commodities in the County in 2012 were grapes, almonds, milk, citrus, and pistachios, which together had a gross value of more than $4 billion (Table 4.2-4). The majority of Kern County's agricultural production is located in the San Joaquin Valley within the Project Area.

Table 4.2-4: Top 20 Commodities and Value of Products Sold in Kern County, 2012

Rank	Commodity	Value
1	Grapes, All	$1,498,987,000
2	Almonds, Including By-Products	$821,857,000
3	Milk, Market and Manufacturing	$690,062,000
4	Citrus, Fresh and Processing	$620,350,000
5	Pistachios	$486,213,000
6	Cattle and Calves	$382,913,000
7	Carrots, Fresh and Processing	$350,439,000
8	Hay, Alfalfa	$213,466,000
9	Cotton, Including Processed Cottonseed	$147,637,000
10	Potatoes, Fresh and Processing	$85,102,000
11	Silage and Forage	$75,149,000
12	Pomegranates, Fresh and Processing	$58,781,000
13	Nursery, Fruit and Nut Trees and Vines	$57,555,000
14	Apiary Products	$56,707,000
15	Tomatoes, Fresh and Processing	$53,657,000
16	Eggs and Egg Product	$40,343,000
17	Bell Peppers, Fresh and Processing	$40,143,000
18	Wheat	$35,294,000
19	Nursery, Roses	$33,346,000
20	Onions, Fresh and Dehydrated	$28,350,000

Table 4.2-5 displays a breakdown of crop types within the Project Area, grouped into general categories and by Subarea. In the Project Area, orchards and vineyards make up the majority of general crop types (approximately 52%), followed by row crops (approximately 38%).

Table 4.2-5: General Categories of Crop Types Within the Project Area, 2012

Crop Type	Western Subarea	Central Subarea	Eastern Subarea
Orchard/Vineyard	50%	59%	48%
Pasture/Sod	<1%	<1%	1%
Row Crops	34%	37%	43%
Uncultivated	16%	4%	8%

Farmland Mapping and Monitoring Program (FMMP) data for Kern County show that, in contrast with the state as a whole, the acreage of land that meets the program's definition of "grazing land" has increased in the County since the mid-1980s. The FMMP provides Kern County grazing land acreage estimates for the periods 1988–2004 and 2004–2016. As shown in Table 4.2-6, the data indicate that grazing land in the County increased by about 59,000 acres from 1988 to 2004, and by about 58,000 acres from 2004 to 2016.

Table 4.2-6 Kern County Acreage Mapped as Grazing Land in Farmland Mapping and Monitoring Program Biennial Surveys 1988–2004 and 2004–2016

1988	2004	Net change
1,729,857	1,789,054	59,197
2004	**2016**	**Net change**
1,791,467	1,849,266	57,799

Source: FMMP 2018.

Note: Since data are separately reported by the FMMP for 1988–2004 and 2004–2016, reported amounts for 2004 differ slightly in each data series. Both series are based on 100% County survey coverage and indicate that from 1988 to 2016, FMMP mapped grazing land in the County increased by over 100,000 acres (e.g., 119,000 acres).

Key:

FMMP = Farmland Mapping and Monitoring Program

Table 4.2-7 summarizes the 1987 and 2012 cattle inventory estimates published by the United States Department of Agriculture, National Agricultural Statistics Service (NASS) for Kern County in conjunction with the five-year national agricultural census conducted in each of these years. The census data are based on surveys completed and returned to NASS during each census period. For reference, Table 4.2-7 also includes the cattle inventory estimates for California in the 1987 census and the 2012 census. As discussed in Section 2.6.2 Baseline, 2012 is the baseline year for the Project's CEQA analysis, as it was the last year for which complete data on oil and gas activities were available from relevant regulatory agencies at the time that the environmental analysis for this SREIR commenced. 1987 is 25 years prior to the 2012 baseline year.

Table 4.2-7 Kern County and California Cattle Inventory, First of January 1987 and 2012 National Agricultural Statistics Service Census of Agriculture Number of Head [(a)]

	2012 Census	1987 Census
Kern County		
Beef cows	30,427	50,020
Milk cows	130,828	20,392
Other cattle (steers, heifers, bulls and calves)	181,128	141,891
Total cattle	342,383	212,303
California		
Beef cows	583,594	906,006
Milk cows	1,815,655	1,070,366
Other cattle (steers, heifers, bulls and calves)	2,971,282	2,594,295
Total cattle	**5,370,531**	**4,570,667**
Kern County, percent of State		
Beef cows	5.2%	5.5%
Milk cows	7.2%	1.9%
Other cattle (steers, heifers, bulls and calves)	6.1%	5.5%
Total Cattle	**6.4%**	**4.6%**

Sources: NASS 1987, 2012.

Note:

(a) Numbers differ from those for breeding cows from FRAP 2010 (shown in Figure 4.2-4) because the NASS census is not limited to breeding cows.

Figure 4.2-1 shows the total number beef cows, milk cows, and other cattle in Kern County in the 1987 and 2012 NASS census reports (NASS 1987, 2012).

The census data show that, with the exception of beef cows, the number of cattle in Kern County, and the share of total California cattle in the County, increased from 1987 to 2012. The number of milk cows in the County rose by over 110,000 head, and the number of steers, heifers, bulls, and calves in the County rose by nearly 40,000 head. The County accounted for 4.6% of the state's total cattle inventory in the 1987 census, and 6.4% of the state's inventory in the 2012 census.

Table 4.2-8 summarizes the 1987 census and 2012 census sheep inventory estimates published by NASS for Kern County. For reference, Table 4-3 also includes the sheep inventory estimates for California.

Table 4.2-8 Kern County and California Sheep Inventory, First of January 1987 and 2012 National Agricultural Statistics Service Census of Agriculture

	2012 Census	1987 Census
Kern County		
Sheep	114,571	174,996
California		
Sheep	596,163	979,506
Kern County, percent of State		
Sheep	19.2%	17.9%

Sources: NASS 1987, 2012.

The census data show that, consistent with the trends identified in Figure 4.2-2, sheep ranching in California and Kern County continued to decline from the peak activity levels in the 1940s. However, the decline in the inventory of sheep was smaller in the County (-54%) than statewide (-64%) between the 1987 census and 2012 census. The percentage of the total California sheep inventory in Kern County increased to over 19% in 2012 from just under 18% in the 1987 census.

Sheep and cattle grazing have historically accounted for almost all of the value of grazing activity in Kern County. In 1987, 92% of the total value, or gross revenue reported for livestock in the County was from sheep and cattle operations, of which 57% was related to cattle. In 2012, as the sheep industry declined nationally, in the state and in Kern County, sheep and cattle operations accounted for 99.8% of livestock revenue in the County, and cattle accounted for 97% of the total. (Kern County Department of Agriculture and Measurement Standards 1987, 2012).

Local

The Project Area (shown on Figure 3-1) encompasses 2,362,734 acres and is generally bounded on the north and west by the Kern County line, on the south by the San Emigdio Mountains, and on the east by the Greenhorn Mountains. The Western Subarea extends from the western boundary of the County to Interstate 5; the Central Subarea lies between Interstate 5 and State Highway 99 north to Bakersfield and then generally following State Highway 65 to the northern county line (with some exceptions); the Eastern Subarea extends from this eastern boundary of the Central Subarea to the foothills of the Greenhorn Mountains.

Zoning within the Project Area is a combination of: Exclusive Agriculture (A), Limited Agriculture (A-1); Estate (E), Low-Density Residential (R-1), Medium-Density Residential (R-2), High-Density Residential (R-3) Mobile home Park (MP); Commercial Office (CO), Neighborhood Commercial (C-1), General Commercial (C-2), Highway Commercial (CH); Light Industrial (M-1), Medium Industrial (M-2), Heavy Industrial (M-3), and Special Purpose Districts, including Recreation-Forestry (RF), Open Space (OS), Natural Resource (NR), Drilling Island (DI), Floodplain Primary (FPP), Special Planning (SP) and Platted Lands (PL). Table 4.2-9 provides the number of acres of lands zoned as either A or A-1 in each subarea.

Table 4.2-9: Acreages of Lands Zoned for Agricultural Use in the Project Area (2014)

Zone	Western Subarea	Central Subarea	Eastern Subarea	Project Area Total
Exclusive Agriculture (A)	954,885	556,520	480,923	1,992,327
Limited Agriculture (A-1)	105,364	8,144	27,552	141,060
TOTAL	**1,060,248**	**564,664**	**508,475**	**2,133,387**

According to the most recent report available from the California Department of Conservation (DOC 2012), in the Project Area, there are 582,856 acres of Prime Farmland, 210,957 acres of Farmland of Statewide Importance, and 86,512 acres of Unique Farmland as shown on the maps prepared pursuant to the Farmland Mapping and Monitoring Program (FMMP) of the California Resources Agency (Table 4.2-10). Figure 4.2-3 depicts the FMMP mapping categories within the Project Area and Subareas.

Table 4.2-10: Acreages of Farmland Mapping and Monitoring Program Agricultural Land in the Project Area

FMMP Mapping Category	Western Subarea	Central Subarea	Eastern Subarea	Project Area Total
Prime Farmland	188,558	286,511	107,786	582,856
Farmland of Statewide Importance	55,308	115,701	39,949	210,957
Unique Farmland	34,288	29,032	23,192	86,512
FARMLAND SUBTOTAL	278,154	431,244	170,927	880,326
Confined Animal Agriculture	1,047	5,159	1,256	7,462
Grazing Land	585,011	58,655	338,500	982,166
TOTAL	**864,212**	**495,059**	**510,683**	**1,869,954**

Source: DOC 2012
Note: Acres may not total exactly, due to rounding.
Key:
FMMP = Farmland Mapping and Monitoring Program

Not all of the Prime Farmland, Farmland of Statewide Importance, and Unique Farmland (collectively referred to in this section as “Farmland”) are actively farmed. Geographic information system (GIS) analysis of annual actively farmed land from records spanning from 2005 to 2014 provides a 10-year average of the acreage of land in the Project Area that has been farmed for five out of the last ten years, which averages 91.5% of the total amount of Farmland.

Kern County’s agricultural areas are facing increasing pressure to convert productive farmland to housing, industrial, and commercial development. In 2013, the County approved amendments that re-designated 1,165 net acres of agricultural lands to non-agricultural use. The total loss of agricultural lands in the unincorporated area of the County from 1998 to 2013 was 16,273 acres. The net average annual conversion rate over the 15-year period was 1,085 acres. However, the majority of converted agricultural lands during this period have been used as a solid waste buffer and continue to be farmed.

A discussion of the SGMA as a factor in the conversion of agricultural land is provided in Chapter 4.9, Hydrology and Water Quality and 4.17, Utilities and Service Systems of this SREIR. This analysis shows that the baseline projections used for potential conversion of agricultural land by the Project, as well as cumulative impacts, are conservative and are affected by other factors, such as commodity prices that are not the result of the Project.

The Kern Council of Governments (COG) projects that Kern County's population will grow from its 2010 Census population of 839,600 to more than 1,441,000 million in 2040 (Kern COG 2014). This growth in population could increase the amount of agricultural land conversion to non-agricultural uses in Kern County even further.

Agricultural Preserves and Williamson Act Land Use Contracts

An agriculture preserve defines the physical boundary of an area within which Kern County could enter into agricultural contracts with landowners, such as Williamson Act contracts (described below), to ensure that agricultural lands remain used for agricultural purposes. The boundary of an agricultural preserve is designated by resolution of the County's Board of Supervisors. Agriculture preserves must generally be at least 100 acres in size. The Project Area includes a 17 agricultural preserves (Preserve Nos. 1 to 14, 17, 18, and 19) (Figure 4.2-4).

The California Land Conservation Act of 1965 (Williamson Act) is a California law that provides property tax relief to owners of farmland and open-space land in exchange for a 10-year agreement that the land will not be developed or otherwise converted to another use. The purposes of the Williamson Act are to protect agricultural resources, to preserve open space, and to promote efficient development patterns. Lands under a Williamson Act contract are taxed at a rate based on the actual use of the land for agricultural purposes, as opposed to its unrestricted market value. The landowner commits the parcel to a 10-year period wherein no conversion out of agricultural use is permitted. The contracts are automatically renewed each year unless a notice of non-renewal is filed by the landowner with the County Clerk. Non-renewal or immediate cancellation does not change the zoning of the property. As of 2013, it is estimated that 16 million of the state's 30 million acres of farm and ranch land are currently protected under the Williamson Act (DOC 2013).

Soil quality is not the only factor in qualifying for Williamson Act protection. For example, lesser quality soils support grazing and livestock production and these land uses meet Williamson Act objectives. A provision of the Williamson Act is that land use compatibility of agricultural lands is determined by the local government (see Section 4.2.3, Regulatory Setting).

A Farmland Security Zone (FSZ) is an area created within an agricultural preserve upon request by a landowner or group of landowners. FSZs function similarly to Williamson Act contracts;

however, the length of the contract is 20 years rather than 10 years. As with land covered by a Williamson Act Contract, FSZs offer landowners a significant property tax reduction.

The California Land Conservation Act 2012 Status Report (DOC 2013) presents statewide statistics for Williamson Act and FSZ contracts, broken down by county. The most recent report available covers the years 2010 and 2011. According to this report, Kern County had the fourth highest acreage of new Williamson Act enrollments in the state in both 2010 and 2011, with 2,400 and 2,113 acres, respectively. Kern County was ranked first in the state in Nonrenewal Initiations in 2010, and third in 2011, totaling 12,339 acres for those two years (DOC 2013). Section 4.2.3, Regulatory Setting, provides additional information about the Williamson Act.

The locations and acreages of Williamson Act and FSZ contract lands within the Project Area are shown in Table 4.2-11. There are 1,136,193 acres of land within the Project Area that are within Williamson Act or FSZ Act renewal parcels.

Table 4.2-11: Acreages of Williamson Act and Farmland Security Zone Contracts in the Project Area – County Jurisdiction (2011)

Contract Category	Western Subarea	Central Subarea	Eastern Subarea	Project Area Total
Williamson Act	371,488	305,206	321,221	997,916
Farmland Security Zone Contracts	101,154	33,278	3,845	138,277
TOTAL	**472,642**	**338,484**	**325,066**	**1,136,193**

Forest Lands and Timberlands

Public Resources Code Section 12220 (g) defines "forest land" as "land that can support 10% native tree cover of any species, including hardwoods, under natural conditions, and that allows for management of one or more forest resources, including timber, aesthetics, fish and wildlife, biodiversity, water quality, recreation, and other public benefits."

Public Resources Code Section 12220 (l) defines "woodlands" as "forest lands composed mostly of hardwood species such as oak."

Government Code Section 51104 (f) defines "timberland" as "privately owned land, or land acquired for State forest purposes, which is devoted to and used for growing and harvesting timber, or for growing and harvesting timber and compatible uses, and which is capable of growing an average annual volume of wood fiber of at least 15 cubic feet per acre."

The Project Area does not support woodlands or forest lands. According to the California Department of Forestry and Fire Protection's Fire and Resource Assessment Program, there are no Timberland Production Zones in Kern County (CAL FIRE 2010). Therefore, forest and timberlands are not analyzed in this section.

Rangeland/Grazing Land Use and Oil and Gas Operations in Kern County

As shown in Table 4.2-10, above, approximately 982,166 acres of the Project Area in 2012 consists of grazing land as defined by the mapping criteria used by the FMMP. The FMMP GIS files for the Project Environmental Impact Report base year of 2012 were obtained by Kern County GIS specialists in the Planning and Natural Resources Department and used to tabulate and map FMMP grazing land in the Project Area. Table 4.2-12 summarizes the mapped grazing land acreage in 2012 by Tier and Project Subarea.

Table 4.2-12 Farmland Mapping and Monitoring Program Grazing Land Acreage in Project Area by Tier and Subarea 2012

Tier	Western Subarea	Central Subarea	Eastern Subarea	Total
Tier 1	65,846	1,064	16,267	83,177
Tier 2	481,760	44,620	296,838	823,218
Tier 3	544	482	3,211	4,237
Tier 4	3,037	771	5,127	8,935
Tier 5	697	-	378	1,075
Non-jurisdictional and “Other” Land	33,507	11,638	16,379	61,524
TOTAL	**585,392**	**58,576**	**338,198**	**982,166**

Sources: Compiled from FMMP GIS data for 2012.

Figure 4.2-5 shows the locations of FMMP grazing land in the Project Area by Tier and Subarea. Approximately 6% (61,524 acres) of the total mapped grazing land is in non-jurisdictional (including “other” land) portions of the Project Area that are not subject to the amended Ordinance. Approximately 91% (831,391 acres) of grazing land is located in Tiers 2 to 5. Based on the conservative disturbance factors used in the 2015 FEIR, about 9% of total potential land disturbance related to oil and gas activity subject to the Ordinance will occur in Tiers 2-5 of the Project Area. Approximately 8% (83,177 acres) of the mapped grazing land in the Project Area is located in Tier 1. Approximately 91% of the total potential land disturbance related to oil and gas activity subject to the Ordinance will occur in Tier 1 of the Project Area.

At the request of the County, the Western States Petroleum Association (WSPA), a Project Proponent, obtained information on acres leased and leasing terms for livestock grazing by oil and gas operators. A memorandum summarizing this information is included as Appendix F of the 2018 Supplemental Environmental Impact Report (SEIR) (SREIR Volume 8). The memorandum reviews the acres leased for livestock grazing for nine oil and gas operators. Seven of the operators lease a total of 108,090 acres in Kern County for grazing and include the County’s three largest oil and gas operators by volume of annual production. Two respondents did not lease land for grazing. The average number of acres leased by the seven operators that lease grazing land is 15,441 acres, and the amount of leased land per operator ranges from 640 to 37,000 acres.

Five oil and gas operators provided sample grazing leases to identify typical lease provisions. As summarized by WSPA, the leases typically include the following provisions:

a) Parties to the lease.

b) Leased land description.

c) Lease term.

d) Lease rent.

e) Requirements that the grazing lessee will maintain the leased premises, including fences, water tanks and other improvements, in good condition.

f) Specified improvements that grazing lessees may construct, such as fences, or construct with lessor approval.

g) Requirements that the grazing lessee will remove improvements at lease termination, unless lessor consents to the improvements remaining.

h) Requirements that grazing lessee provide water for livestock.

i) Requirements that grazing lessee will take reasonable steps to control erosion, fire hazards and weeds. Some but not all leases require compliance with U.S. Department of Interior, Bureau of Land Management's Central California Standards for Rangeland Health and Guidelines for Livestock Grazing Management.

j) Retention by the lessor of rights of access and rights to explore, drill and produce minerals, construct roads, pipelines and other oil and gas related improvements.

k) Insurance and indemnity provisions.

l) Procedural provisions including assignment, notice, governing law, etc.

Livestock grazing is also employed as a land management technique on acreage set aside for habitat conservation purposes. No oil and gas production takes place on acreage where production is excluded by the terms of habitat conservation easements. Certain operators contract with goat herd managers to control invasive weeds on their lands. As discussed above, livestock grazing other than by cattle and sheep represents a statistically negligible share of the total livestock value reported in annual Kern County crop reports.

Table 4.2-12, above, shows that about 94% of the grazing land in the Project Area is located in the Eastern Subarea (338,198 acres) and the Western Subarea (585,392 acres), with approximately 6% in the Central Subarea (58,576 acres). Grazing lands in the Eastern and Western Subareas support annual, mainly non-native forage consumed by livestock in the foothills fringing the valley. Of all oil and gas Tier 1 areas—which contain the most intensively developed existing oil and gas operations in the Project Area, and comprise the locations where 91% of all future development subject to the Ordinance is expected to occur—98.5% are in the Western Subarea (163,227 acres) and the Eastern Subarea (40,518). Figure 4.2-5 shows the vast majority of Tier 1 areas lie within the Western and Eastern Subareas. Figure 4.2-6 and Figure 4.2-7 shows that a similar proportion of grazing land is located in Tier 1 areas within those regions. Consequently, the most intensive livestock grazing and oil and gas activities have occurred in the same portions of the Project Area for decades.

There are published reports of impacts to grazing livestock from exposure to oil well stimulation constituents and related oil and gas activities in other states (DeDonder et al. 2015). A search of publicly available records in July 2018, however, did not identify any lawsuits, legal claims, news reports, or studies suggesting that exposure to oil and gas activities has ever caused harm to livestock in Kern County. The record search also did not identify any lawsuits, claims, news reports, or studies indicating that livestock operations in the County have been adversely affected by split-estate landholdings. Thus, livestock grazing has not resulted in the kinds of land use conflicts that have occurred between irrigated agriculture and oil and gas operations, which were discussed in the 2015 FEIR and addressed in the Ordinance. For example, as discussed in the 2015 FEIR, lawsuits by orchard growers have been filed against certain oil and gas operators in the past based on assertions that oil and gas operations contaminated irrigation groundwater and harmed their trees. Damages were awarded to an orchard operator in a 2001 case, and a lawsuit filed in 2014 remains pending (see, e.g., 2015 FEIR Chapter 12, pages 12-106, 107 [SREIR Volume 8]). The 2015 FEIR (see, e.g., 2015 FEIR pages 3-16 to 3-17) also discussed land use conflicts between farmers and oil and gas operators on lands where the surface owners are different from the mineral rights holders (so-called "split-estates"). The amendments and revisions to the Ordinance include a new surface owner signature process in response to this issue (see Kern County Zoning Ordinance Sections 19.98.090 and 19.98.100). Figure 4.2-8 depicts the location of irrigated farmland in the Project Area as of 2013.

No documentation concerning livestock impacts related to oil and gas operations or split-estate controversies affecting grazing in Kern County were received by the County during the Notice of Preparation (NOP) comment period for the 2018 SEIR.

4.2.3 Regulatory Setting

Federal

Farmland Protection Policy Act (7 U.S.C. Section 4201)

The purpose of the Farmland Protection Policy Act (FPPA) is to minimize the extent to which federal programs contribute to the unnecessary and irreversible conversion of farmland to nonagricultural uses. The FPPA additionally directs federal programs to be compatible with state and local policies for the protection of farmlands. Congress passed the Agriculture and Food Act of 1981 (Public Law 97-98) containing the FPPA—Subtitle I of Title XV, Section 1539-1549. The final rules and regulations were published in the Federal Register on June 17, 1994.

The FPPA is intended to minimize the impact federal programs have on the unnecessary and irreversible conversion of farmland to nonagricultural uses. It ensures that, to the extent possible, federal programs are administered to be compatible with state, local units of government, and private programs and policies to protect farmland. Federal agencies are required to develop and review their policies and procedures to implement the FPPA every two years. The FPPA does not authorize the federal government to regulate the use of private or nonfederal land or, in any way, affect the property rights of owners.

For the purpose of the FPPA, farmland includes prime farmland, unique farmland, and land of statewide or local importance. Farmland subject to FPPA requirements does not have to be currently used for cropland. It can be forest land, pastureland, cropland, or other land, but not water or urban built-up land.

Projects are subject to FPPA requirements if they may irreversibly convert farmland (directly or indirectly) to nonagricultural use and are completed by a federal agency or with assistance from a federal agency.

State

California Department of Conservation, Division of Land Resource Protection – Farmland Mapping and Monitoring Program

The California Department of Conservation (DOC) applies the Natural Resources Conservation Service soil classifications to identify agricultural lands, and these agricultural designations are used in planning for the present and future of California's agricultural land resources. The DOC has a minimum mapping unit of 10 acres, with parcels that are smaller than 10 acres being absorbed into the surrounding classifications.

Farmland Mapping and Monitoring Program

The list below provides a comprehensive description of all the categories mapped by the DOC (DOC 2015). As noted above, lands classified as Prime Farmland, Farmland of Statewide Importance, and Unique Farmland are referred to as Farmland (DOC 2004).

- **Prime Farmland (P):** Irrigated land with the best combination of physical and chemical features able to sustain long-term production of agricultural crops. This land has the soil quality, growing season, and moisture supply needed to produce sustained high yields. Land must have been irrigated for production of irrigated crops at some time during the four years prior to the mapping date.
- **Farmland of Statewide Importance (S):** Irrigated land similar to Prime Farmland that has a good combination of physical and chemical characteristics for the production of agricultural crops. This land has minor shortcomings, such as greater slopes or less ability to store soil moisture than Prime Farmland. Land must have been irrigated for production of irrigated crops at some time during the four years prior to the mapping date.
- **Unique Farmland (U):** Lesser quality soils used for the production of the state's leading agricultural crops. This land is usually irrigated, but may include non-irrigated orchards or vineyards as found in some climatic zones in California. Land must have been cropped at some time during the four years prior to the mapping date.
- **Farmland of Local Importance (L):** Although counties may choose to define Farmland of Local Importance within their jurisdictions, the Board of Supervisors has determined that there will be no Farmland of Local Importance for Kern County.
- **Confined Animal Agriculture (C):** Although counties typically include Confined Animal Agriculture in the Farmland of Local Importance category, Kern County defines Confined Animal Agriculture as a separate FMMP category.
- **Grazing Land (G):** Land on which the existing vegetation is suited to the grazing of livestock. This category is used only in California and was developed in cooperation with

the California Cattlemen's Association, University of California Cooperative Extension, and other groups interested in the extent of grazing activities.

- **Urban and Built-up Land.** Land occupied by structures with a building density of at least one unit to 1.5 acres, or approximately six structures to a 10-acre parcel. This land is used for residential, industrial, commercial, institutional, public administrative purposes, railroad and other transportation yards, cemeteries, airports, golf courses, sanitary landfills, sewage treatment, water control structures, and other developed purposes.
- **Other Land.** Land not included in any other mapping category. Common examples include low density rural developments; brush, timber, wetland, and riparian areas not suitable for livestock grazing; confined livestock, poultry or aquaculture facilities; strip mines and borrow pits; and water bodies smaller than 40 acres. Vacant and non-agricultural land surrounded on all sides by urban development and greater than 40 acres is mapped as Other Land.

California Rangeland, Grazing Land, and Grassland Protection Act – Public Resources Code

The Rangeland, Grazing Land, and Grassland Protection Act was enacted in 2002 to protect California's rangeland, grazing land, and grasslands through the use of conservation easements. This act designates the Wildlife Conservation Board as the lead agency in the state for acquiring conservation easements to protect rangeland, grazing lands, and grasslands in accordance with the criteria of the act. The Wildlife Conservation Board defines grazing land to mean "(1) a collective term for rangeland, pastureland, grazing forest land, native and naturalized pasture, hayland, and grazed cropland. Although grazing is generally a predominate use, the term is used independent of any use. (2) Land is used primarily for production of forage plants maintained or manipulated primarily through grazing management. Includes all land having plants harvestable by grazing without reference to land tenure, other land uses or management practices." The board administers the act by accepting applications for easements that meet certain program requirements, including the protection of the integrity of rangeland, grazing lands, and grasslands.

California Forest and Rangeland Resources Assessment and Policy Act of 1977 – Public Resources Code

Section 4789.3 of the Forest and Rangeland Resources Assessment and Policy Act requires that the California Resources Agency prepare and submit to the State Board of Forestry and Fire Protection and the Secretary of the Resources Agency a forest and rangeland resource assessment every five years from January 1, 1987. The most recent assessment was prepared and published in 2010, and no subsequent assessment has been publicly released (FRAP 2010). Section 4789.2 (i) of this act defines "Rangeland" as "land on which the existing vegetation, whether growing naturally or through management, is suitable for grazing or browsing of domestic livestock for at least a portion of the year. Rangeland includes any natural grasslands, savannas, shrublands (including chaparral), deserts, wetlands, and woodlands (including Eastside ponderosa pine, pinyon, juniper, and oak) which support a vegetative cover of native grasses, grasslike plants, forbs, shrubs, or naturalized species."

California Land Conservation Act (Williamson Act)

The California Land Conservation Act of 1965, commonly referred to as the Williamson Act, is promulgated in California Government Code Section 51200-51297.4 and, therefore, applies only to specific land parcels within the state of California. The Williamson Act enables local governments to enter into contracts with private landowners for the purpose of restricting specific parcels of land to agricultural or compatible uses in return for reduced property tax assessments. Private land within locally designated agricultural preserve areas is eligible for enrollment under Williamson Act contracts. The Williamson Act program is administered by the DOC, in conjunction with local governments, which administer the individual contract arrangements with landowners. The landowner commits the parcel to a 10-year period wherein no conversion out of agricultural use is permitted. Each year the contract automatically renews unless a notice of non-renewal or cancellation is filed. In return, the land is taxed at a rate based on the actual use of the land for agricultural purposes, as opposed to its unrestricted market value. An application for immediate cancellation can also be requested by the landowner, provided that the proposed immediate cancellation application is consistent with the cancellation criteria stated in the California Land Conservation Act and those adopted by the affected county or city. Non-renewal or immediate cancellation does not change the zoning of the property. Participation in the Williamson Act program is dependent on county adoption and implementation of the program and is voluntary for landowners.

The Williamson Act states that a board or council by resolution shall adopt rules governing the administration of agricultural preserves. The rules of each agricultural preserve specify the uses allowed. Generally, any commercial agricultural use will be permitted within any agricultural preserve. In addition, local governments may identify compatible uses permitted with a use permit (California Code 2014).

California Government Code Section 51238 states that boards of supervisors may impose conditions on lands or land uses to be placed within preserves to permit and encourage compatible uses in conformity with Section 51238.1. The Kern County Agricultural Preserve Standard Uniform Rules specify that oil and gas drilling and production in accordance with the provisions of Chapter 19.98 of the Ordinance Code of Kern County are compatible uses in agricultural preserves.

Further, California Government Code Section 51238.1 allows a board or council to allow as compatible any use that without conditions or mitigations would otherwise be considered incompatible. However, this may occur only if that use meets the following conditions:

- The use will not significantly compromise the long-term productive agricultural capability of the subject contracted parcel or parcels on other contracted lands in agricultural preserves.

- The use will not significantly displace or impair current or reasonably foreseeable agricultural operations on the subject contracted parcel or parcels or on other contracted lands in agricultural preserves. Uses that significantly displace agricultural operations on the subject contracted parcel or parcels may be deemed compatible if they relate directly to the production of commercial agricultural products on the subject contracted parcel or parcels or neighboring lands, including activities such as harvesting, processing, or shipping.
- The use will not result in the significant removal of adjacent contracted land from agricultural or open-space use.

A board or council may approve uses on nonprime land, which, because of offsite or onsite impacts, would not comply with the first two criteria, provided that the use is approved pursuant to a conditional use permit that sets forth findings required by California Government Code Section 51238.1(c).

Farmland Security Zone Act

The Farmland Security Zone Act is similar to the Williamson Act and was passed by the California State Legislature in 1999 to ensure that long-term farmland preservation is part of public policy. Farmland Security Zone Act contracts are sometimes referred to as “Super Williamson Act Contracts.” Under the provisions of this act, a landowner already under a Williamson Act contract can apply for FSZ status by entering into a contract with the County. FSZ classification automatically renews each year for an additional 20 years. In return for a further 35% reduction in the taxable value of land and growing improvements (in addition to Williamson Act tax benefits), the owner of the property promises not to develop the property into nonagricultural uses.

Local

Kern County General Plan

The Project Area is located within the Kern County General Plan (KCGP) area and, therefore, would be subject to applicable policies and measures of the KCGP. The Land Use, Conservation, and Open Space Element of the KCGP includes goals, policies, and implementation measures related to agricultural and forestry resources that apply to the Project, as described below.

The KCGP’s Land Use Element establishes a number of land use designations, five of which fall within the “Resource” land use category (see Table 4.2-13). The definition of “Resource Reserve” (Map Code 8.2) includes rangeland, and livestock grazing is an allowable use in four of the five designations. The fifth designation, Mineral and Petroleum, includes Extensive and Intensive Agriculture, both categories that include livestock grazing as an allowable use.

Table 4.2-13 Kern County General Plan Land Use Designations and Map Codes: Resource

Land Use Designation	Map Code	Definition	Uses Allowed
Intensive Agriculture	**8.1**	Areas devoted to the production of irrigated crops or having a potential for such use. Other agricultural uses, while not directly dependent on irrigation for production, may also be consistent with the intensive agriculture designation.	Irrigated cropland; orchards; vineyards; horse ranches; raising of nursery stock ornamental flowers and Christmas trees; fish farms' bee keeping' ranch and farm facilities and related uses; one single-family dwelling unit; cattle feed yards; dairies; dry land farming; livestock grazing; water storage; groundwater recharge acres; mineral; aggregate; and petroleum exploration and extraction; hunting clubs; wildlife preserves; farm labor housing; public utility uses; and agricultural industries pursuant to provisions of the Kern County Zoning Ordinance, and land within development areas subject to significant physical constraints.
Resource Reserve	**8.2**	Areas of mixed natural resource characteristics, such as rangeland, woodland, and wildlife habitat which occur within an established County water district. Minimum parcel size is 20 acres gross, except lands subject to a Williamson Act Contract/Farmland Security Zone Contract, in which case the minimum parcel size shall be 80 acres gross.	Livestock grazing; dry land farming; ranching facilities; wildlife and botanical preserves; and timber harvesting; one single-family dwelling unit; irrigated croplands; water storage or groundwater recharge areas; mineral; aggregate; and petroleum exploration and extraction; recreational activities, such as gun clubs and guest ranches; and land within development areas subject to significant physical constraints.
Extensive Agriculture	**8.3**	Agricultural uses involving large amounts of land with relatively low value-per-acre yields, such as livestock grazing, dry land farming, and woodlands. Minimum parcel size is 20 acres gross, except lands subject to a Williamson Act Contract/ Farmland Security Zone Contract, in which case the minimum parcel size shall be 80 acres gross.	Livestock grazing; dry land farming; ranching facilities; wildlife and botanical preserves; and timber harvesting; one single-family dwelling unit; irrigated croplands; water storage or groundwater recharge areas; mineral; aggregate; and petroleum exploration and extraction; and recreational activities, such as gun clubs and guest ranches; and land within development areas subject to significant physical constraints.

Table 4.2-13 Kern County General Plan Land Use Designations and Map Codes: Resource

Land Use Designation	Map Code	Definition	Uses Allowed
Mineral and Petroleum	**8.4**	Areas which contain producing or potentially productive petroleum fields, natural gas, and geothermal resources, and mineral deposits of regional and Statewide significance. Uses are limited to activities directly associated with the resource extraction. Minimum parcel size is 5 acres gross.	Mineral and petroleum exploration and extraction, including aggregate extraction; extensive and intensive agriculture; mineral and petroleum processing (excluding petroleum refining); natural gas and geothermal resources; pipelines; power transmission facilities; communication facilities; equipment storage yards; and borrow pits.
Resource Management	**8.5**	Primarily open space lands containing important resource values, such as wildlife habitat, scenic values, or watershed recharge areas. These areas may be characterized by physical constraints, or may constitute an important watershed recharge area or wildlife habitat or may have value as a buffer between resource areas and urban areas. Other lands with this resource attribute are undeveloped, non-urban areas that do not warrant additional planning within the foreseeable future because of current population (or anticipated increase), marginal physical development, or no subdivision activity.	Recreational activities; livestock grazing; dry land farming; ranching facilities; wildlife and botanical preserves; and timber harvesting; one single-family dwelling unit; irrigated croplands; water storage or groundwater recharge areas; mineral; aggregate; petroleum exploration and extraction; open space and recreational uses; one single-family dwelling on legal residentially zoned lots on effective date of this General Plan; land within development areas subject to significant physical constraints; State and federal lands which have been converted to private ownership.

Petroleum exploration and extraction are allowable uses in all three of the KCGP's agricultural designations.

The policies and implementation measures in the KCGP for Agriculture and Forest Resources applicable to the proposed Project are outlined below. The KCGP contains additional policies, goals, and implementation measures that are general in nature and not specific to development such as the Project. Therefore, these measures are not listed below, but, as stated in Chapter 2, Introduction, all policies, goals, and implementation measures in the KCGP are incorporated by reference.

Chapter 1. Land Use, Conservation, and Open Space Element

1.4. Public Facilities and Services

Goals

Goal 5. Ensure that adequate supplies of quality (appropriate for intended use) water are available to residential, industrial, and agricultural users within Kern County.

1.9. Resource

Goals

Goal 1. To contain new development within an area large enough to meet generous projections of foreseeable need, but in locations which will not impair the economic strength derived from the petroleum, agriculture, rangeland, or mineral resources, or diminish the other amenities which exist in the County.

Goal 2. Protect areas of important mineral, petroleum, and agricultural resource potential for future use.

Goal 3. Ensure the development of resource areas minimize effects on neighboring resource lands.

Goal 5. Conserve prime agriculture lands from premature conversion.

Policies

Policy 1. Appropriate resource uses of all types will be encouraged as desirable and consistent interim uses in undeveloped portions of the County regardless of General Plan designation.

Policy 2. In areas with a resource designation on the General Plan map, only industrial activities which directly and obviously relate to the exploration, production, and transportation of the particular resource will be considered to be consistent with the General Plan.

Policy 5. Areas of low intensity agriculture use (Map Code 8.2 (Resource Reserve), Map Code 8.3 (Extensive Agriculture), and Map Code 8.5 (Resource Management)) should be of an economically viable size in order to participate in the state Williamson Act Program/Farmland Security Zone Contract.

Policy 7. Areas designated for agricultural use, which include Class I and II and other enhanced agricultural soils with surface delivery water systems, should be protected from incompatible residential, commercial, and industrial subdivision and development activities.

Policy 11. Minimize the alteration of natural drainage areas. Require development plans to include necessary mitigation to stabilize runoff and silt deposition through utilization of grading and flood protection ordinances.

Policy 12. Areas identified by the Natural Resource Conservation Service (formerly Soil Conservation Service) as having high range-site value should be conserved for Extensive Agriculture uses or as Resource Reserve, if located within a County water district.

Policy 15. Agriculture and other resource uses will be considered a consistent use in areas designated for Mineral and Petroleum Resource uses on the General Plan.

Policy 21. The County shall encourage qualifying agricultural lands to participate in the Williamson Act program or Farmland Security Zone program.

Implementation Measures

Implementation Measure B. Areas designated as Resource Reserve (Map Code 8.2), Extensive Agriculture (Map Code 8.3), Resource Management (Map Code 8.5) that are under Williamson Act Contracts or Farmland Security Zone Contracts will have a minimum parcel size of 80 acres until such time as a contract is expired or is cancelled, at which time the minimum parcel size will become 20 acres.

Implementation Measure C. The County Planning Department will seek review and comment from the County Engineering, Surveying, and Permit Services Department on the implementation of the National Pollution Discharge Elimination System for all discretionary projects.

Implementation Measure F. Prime agricultural lands, according to the Kern County Interim-Important Farmland map produced by the Department of Conservation, which have Class I or II soils and a surface delivery water system shall be conserved through the use of agricultural zoning with minimum parcel size provisions.

Implementation Measure G. Property placed under the Williamson Act/Farmland Security Zone Contract must be in a Resource designation.

Implementation Measure K. Protect oilfields and mineral extraction areas through the use of appropriate implementing Zone Districts: A (Exclusive Agriculture), DI (Drilling Island), NR (Natural Resource), or PE (Petroleum Extraction).

Metropolitan Bakersfield General Plan

The Metropolitan Bakersfield General Plan (MBGP), a joint effort between the Kern County Planning and Natural Resources Department and the City of Bakersfield Planning Division, was last adopted on December 11, 2007. The MBGP includes both city and unincorporated County lands. It describes the community's physical development as well as its economic, social, and environmental goals and is currently undergoing an update. The Project Area includes a total of 152,040 acres of unincorporated County lands that are covered under the MBGP (7.41%). Project-related development on unincorporated lands within the MBGP Planning Area would be subject to the following applicable policies and implementation measures of the MBGP, with respect to agricultural and forestry resources.

Chapter V. Conservation Element

C. Soils and Agriculture

Goals

Goal 1. Provide for the planned management, conservation, and wise utilization of agricultural land in the Planning Area.

Goal 2. Promote soil conservation and minimize development of prime agricultural land as defined by the following criteria:

- Capability Class I and/or II irrigated soils.
- 80-100 Storie Index rating.
- Gross crop return of $200 or more per acre per year.
- Annual carrying capacity of 1 animal unit per acre per year.

Goal 3. Establish urban development patterns and practices that promote soil conservation and that protect areas of agricultural production of food and fiber crops, and nursery products.

Policies

Policy 1. Determine the extent and location of all prime agricultural land within the study area (I-1).

Policy 2. Review projects that propose subdividing or urbanizing prime agricultural land to ascertain how continued commercial agricultural production in the Project vicinity will be-affected (I-2).

Policy 4. Monitor the amount of prime agricultural land taken out of production for urban uses or added within the plan area (I-3).

Policy 7. Land use patterns, grading, and landscaping practices shall be designed to prevent soil erosion while retaining natural watercourses when possible (I-4).

Policy 12. Prohibit premature removal of ground cover in advance of development and require measures to prevent soil erosion during and immediately after construction (I-4).

Implementation Measures

Implementation Measure 2. Evaluate discretionary projects for their impact on agricultural resources.

Implementation Measure 3. Document urban expansion and changes in the amount of agricultural land for purposes of determining cumulative impacts to prime agricultural land.

Kern County Specific Plans

In 2020, Kern County has adopted 37 Specific Plans for properties within the Project Area. These Specific Plans are intended to be an amplification of the goals and policies of the KCGP and are, therefore, consistent therewith. As depicted in Figure 4.10-3, less than 8% of the Project Area is located wholly or partially within adopted Specific Plan areas. Future oil and gas exploration and production activities that would be authorized under the proposed Amendment to Chapter 19.98 (Oil & Gas Production) of the Kern County Zoning Ordinance that would be located within the boundary of an adopted Specific Plan would be regulated according to County zoning, with the exception of the Specific Plans identified as Tier 5.

Kern County Zoning Ordinance

The Kern County Zoning Ordinance designates two agricultural zones:

(A) Exclusive Agriculture: the purpose is to designate areas suitable for agricultural uses and to prevent the encroachment of incompatible uses onto agricultural lands and the premature conversion of such lands to nonagricultural uses. Uses in the A District are primarily limited to agricultural uses and other activities compatible with agricultural uses.

(A-1) Limited Agriculture District: the purpose is to designate areas suitable for a combination of estate-type residential development, agricultural uses, and other compatible uses.

Chapters 19.12 and 19.14 currently include as permitted uses in the A and A-1 zones:

- Cogeneration facility or steam generators, primarily intended for steam production, used for production of oil and gas, excluding coal fired.
- Oil or gas exploration and production pursuant to Chapter 19.98 of this title, including the temporary installation of commercial coaches as accessory to this activity, not to exceed a two- (2-) year period.
- Nonhazardous oil production and/or oily waste disposal facility.
- Nonhazardous oilfield waste treatment or recycling.
- Coal-fired cogeneration facility or steam generators, primarily intended for production of oil or gas (with a conditional use permit).

Kern County Code of Ordinances Section 7.16 (Estray Ordinance)

The California Food and Agriculture Code allows the Kern County Board of Supervisors to declare certain portions of the County as being devoted chiefly to grazing. Areas so designated are generally referred to as “Open Range.” Kern County established an Estray Ordinance in 1942 (Ordinance Code Section 7.16). In such areas, a person may not “take up” any estray (stray) animal found on their property, nor will they have a lien against the animal unless their property is surrounded by a good and substantial fence. In areas not designated as “grazing areas,” a person finding any estray animal on their property (whether fenced or not) may seize the animal and have a lien on the animal for all expenses involved in seizing, keeping, and caring for the animal. Consequently, in an “Open Range,” property owners must fence animals off their property if they do not want them on their property, while in areas not “Open Range,” the animal owners must fence the animals in or run the risk of having those animals “taken up” as estray. The County has implemented a formal process for amending the estray ordinance.

Williamson Act Standard Uniform Rules

Kern County has adopted a set of Agricultural Preserve Standard Uniform Rules that identify land uses that are considered compatible uses within agricultural preserves established under the Williamson Act. These rules are designed to restrict the uses of land enrolled in a Williamson Act contract to agriculture or other compatible uses. The Agricultural Preserve Standard Uniform Rules identify five classes of agricultural uses such as crop cultivation, grazing operations, commercial wind farms, livestock breeding, dairies, and uses that are incidental to agricultural uses allowed within the Agricultural Preserves. The rules also include 19 classes of compatible uses that include, but are not limited to, oil and gas drilling and production in accordance with Chapter 19.98 of the Ordinance Code of Kern County, as well as the erection of gas, electric, communications, water, and other similar public utilities.

Methodology

The evaluation of possible impacts to agricultural resources included the review of the Kern County General Land Use Plan and zoning information; the MBGP; and the most current data regarding the DOC, Division of Land Resource Protection, Important Farmland, and regarding Kern County's Williamson Act lands. Agricultural land conversion associated with oil and gas exploration and production operational activities related to the Project were predicted based on the anticipated land disturbance associated with anticipated oil and gas development described in 2015 FEIR Appendix F (SREIR Volume 4), and compared to the significance thresholds. The methodology used to evaluate potential agricultural conversion is described in detail in 2015 FEIR Appendix H (SREIR Volume 4).

Although the number of acres of grazing land potentially affected by the Project is analyzed and disclosed in the following section, the raw number of acres would be inadequate and misleading as a measure of significance. Grazing of non-native livestock species is an inherently economic activity. CEQA provides that, while economic effects of a project are not significant impacts on the environment, economic effects may be used to determine the significance of physical changes caused by the project. CEQA Guidelines Section 15131(b). To determine the significance of a physical change in grazing, data on revenues received from livestock sales and grazing livestock inventories are utilized in this SREIR. As discussed below, the historic trend demonstrates that grazing productivity has increased in Kern County even as the number of acres utilized for grazing has decreased over time. Moreover, as noted above, the compatibility of livestock grazing in immediate proximity to oil and gas operations demonstrates that Project acres and grazing land acres can overlap considerably without necessarily causing significant impacts and, over time, areas of densely developed well fields have been returned to conditions that facilitate livestock grazing. In addition, grazing itself may be associated with adverse environmental impacts. For example, the Center for Biological Diversity has asserted that the "ecological costs of livestock grazing exceed that of any other western land use. In the arid West, livestock grazing is the most widespread cause of species endangerment. By destroying vegetation, damaging wildlife habitats and disrupting natural processes, livestock grazing wreaks ecological havoc on riparian areas, rivers, deserts, grasslands and forests alike – causing significant harm to species and the ecosystems on which they depend" (CBD 2018). Therefore, choosing a significance methodology and threshold that seeks to conserve the maximum number of grazing land acres would not be environmentally beneficial, especially where the same or greater productivity is being attained on a smaller footprint of grazing land, as demonstrated by the historic data discussed herein.

Thresholds of Significance

The Kern County CEQA Implementation Document and Kern County Environmental Checklist state that a project would normally be considered to have a significant impact if it would:

- Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the Farmland Mapping and Monitoring Program of the California Resources Agency, to non-agricultural use;
- Conflict with existing zoning for agricultural use or a Williamson Act Contract;
- Conflict with existing zoning for, or cause rezoning of, forest land (as defined in Public Resources Code Section 12220(g)), timberland (as defined in Public Resources Code Section 4526), or timberland zoned Timberland Production (as defined by Government Code Section 51104(g));
- Result in the loss of forest land or conversion of forest land to non-forest use;
- Involve other changes in the existing environment which, because of their location or nature, could result in conversion of Farmland to non-agricultural use or conversion of forest land to non-forest use; or
- Result in the cancellation of an open space contract made pursuant to the California Land Conservation Act of 1965 or Farmland Security Zone Contract for any parcel of 100 or more acres (Section 15206(b)(3) Public Resources Code).

Neither Appendix G of the CEQA Guidelines nor the Kern County CEQA Implementation Document and Kern County Environmental Checklist include thresholds of significance for evaluating potential impacts to grazing lands. Accordingly, for the purposes of this SREIR the Project will be considered to have a significant impact on rangeland/grazing land resources if it would substantially decrease the productivity of livestock grazing activity in Kern County.

Project Impacts

Direct impacts on agricultural and forestry resources are the immediate effects of a project. These impacts would include conversion of agricultural or timberland to non-agricultural or timber use; interference with agricultural or timber operations; and disturbance or damage to crops or timber trees from dust, or accidental releases of hazardous materials. Indirect impacts are caused by or would result from a project, but occur later in time or farther in distance than direct impacts. These impacts might include effects from erosion or sedimentation onto agricultural land. Other indirect effects which would impact agriculture along with other uses and resources, such as introduction of invasive exotic species, or increased competition for water resources, are addressed in the chapters on these topics.

Impact 4.2-1: Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland) to Non-Agricultural Use

Oil and gas exploration and production activities that would be authorized through implementation of the proposed Project could result in land disturbance throughout the Project Area, as described in Chapter 3, Project Description. As shown in Table 4.2-14, approximately 364,724 acres of the Core Areas are located within mapped FMMP lands, as shown for each Subarea. The majority of these Core Area FMMP lands are located within Tier 2 (93%) (see Appendix H of the 2015 FEIR [SREIR Volume 4]).

Table 4.2-14: Acreages of Farmland Mapping and Monitoring Program Agricultural Land in Core Areas and Tiers

Core Area or Tier	Western Subarea	Central Subarea	Eastern Subarea	Core Area Total
FMMP Lands in Core Areas				
Core Areas	125,204	143,821	95,698	364,724
Non-Core Areas	152,959	287,423	75,229	515,611
Total FMMP land	278,163	431,244	170,927	880,335
FMMP Lands in Tiers				
Tier 1	0	0	0	0
Tier 2	276,758	394,373	157,842	336,235
Tiers 3–5[a]	N/A	N/A	N/A	N/A

Source: Appendix H of 2015 FEIR (SREIR Volume 4)
Note:
[a] FMMP designated lands were mapped, in limited instances, on lands within Tiers 3, 4 and 5. However, these designations occurred on lands that did not contain agricultural uses, nor did these designations occur on lands with an agricultural zone classification. Therefore, these are not considered further in this analysis.
Key:
FMMP = Farmland Mapping and Monitoring Program
N/A = not applicable

Assessment of potential impacts to agricultural and forestry resources focused on proposed exploration and production activities within areas identified as Tier 2 within the Project Area and land use disturbance associated with those activities.

To estimate potential land use disturbance associated with the proposed oil and gas exploration and production activities, "land use disturbance factors" were developed for each new oil and gas production well (see 2015 FEIR Appendix F [SREIR Volume 4]). The disturbance factors included disturbance associated with all oil and gas facilities as identified in Chapter 3, Project Description, including, but not limited to, well pads, access roads, transmission lines, collection and distribution pipelines, drilling and operational sumps, storage tanks, administrative buildings, steam generators, etc. *As explained in Appendix F of this SREIR, initial land use disturbance factors were calculated on an average per well basis by aerially mapping land disturbance and dividing by the number of wells. The resulting per-well numbers were then rounded up to account* *for area-specific data and to provide a conservative assessment: for the Western Subarea, 1.82 acres, rounded up to 2.0 acres; for the Central Subarea, 1.84 acres, rounded up to 3.0 acres; and for the Eastern Subarea, 0.96 acres, rounded up to 1.20 acres.*

The estimated annual land disturbance associated with future oil and gas exploration and production activities within the Project Area is presented in Table 4.2-15. To provide a conservative analysis, it is assumed that all land disturbed by oil and gas activities within Tier 2 areas would be Farmlands, although, in fact, not all land within Tier 2 is in that category. Therefore, the proposed Project could result in the conversion of 298 acres of Farmlands annually, with 148 acres of conversion occurring in the Western Subarea, 60 acres occurring in the Central Subarea, and 90 acres in the Eastern Subarea.

Table 4.2-15: Annual Projected Agricultural Conversion

Subarea	Disturbance Factor (acres)	Anticipated New Producing Wells in Tier 2	Disturbance (acres)
Western	2.0	74	148
Central	3.0	20	60
Eastern	1.20	75	90
TOTAL		**169**	**298**

Source: see 2015 FEIR Appendix H (SREIR Volume 4)
Note: New Producing Well = Oil and Gas, Dry Gas, Dry Hole and Liquid Petroleum Wells, as explained further in Chapter 3, Project Description.

These estimated Tier 2 Farmland disturbance areas from the Project would impact approximately 0.04% of the 828,973 acres of FMMP lands in Tier 2 annually (Table 4.2-16).

Table 4.2-16: Acreages of Farmland Mapping and Monitoring Program Agricultural Land in Tier 2

FMMP Mapping Category	Western Subarea	Central Subarea	Eastern Subarea	Tier 2 Total
Prime Farmland	187,440	252,890	100,116	540,446
Farmland of Statewide Importance	55,147	112,894	35,550	203,591
Unique Farmland	34,170	28,589	22,176	84,935
TOTAL	**276,758**	**394,373**	**157,842**	**828,973**

Source: see 2015 FEIR Appendix H (SREIR Volume 4)
Note: Acres may not total exactly, due to rounding
Key:
FMMP = Farmland Mapping and Monitoring Program

Given the estimated acreage of agricultural land converted annually (Table 4.2-15), the projected amount of FMMP farmland that could be converted between the years 2015 and 2040 in Tier 2 is a total of 7,450 acres (Table 4.2-17). Using this conservative approach, it is estimated that 0.9% of FMMP farmlands in Tier 2 would be impacted by the Project from 2015 to 2040.

Table 4.2-17: Maximum Conversion of Farmland Mapping and Monitoring Program Farmland in Tier 2 (2015 to 2040)

FMMP Mapping Category	Western Subarea	Central Subarea	Eastern Subarea	Project Area Total
Prime Farmland	2,514	978	1,430	4,922
Farmland of Statewide Importance	744	429	507	1,680
Unique Farmland	442	93	313	848
TOTAL	**3,700**	**1,500**	**2,250**	**7,450**

Source: see 2015 FEIR Appendix H (SREIR Volume 4)

The acreage of actively farmed land changes from year to year, and it is not possible to accurately project 25 years into the future. For this analysis, the acreage of land that has been farmed for at least five of the past 10 years (2005 to 2014) was determined. This provided a basis for estimating the percentage of converted Important Farmland that would require mitigation over the 25-year period.

If the rate of active farming (farmed for five of the last 10 years) on Prime Farmland, Farmland of Statewide Importance, and Unique Farmland were to continue at its current rates, then in 25 years, the conversion of actively farmed FMMP farmland would be approximately 3,386 acres in the Western Subarea (91.5%), 1,389 acres in the Central Subarea (92.6%), and 2,092 acres in the Eastern Subarea (93.0%) 2015 FEIR (Appendix H, Table 13 [SREIR Volume 4]).

A review of crop data over the past 10 years suggests that there is a high degree of annual variability among crop types grown from one year to the next. For the purposes of this impact analysis, the percentage of generalized crop types (Table 4.2-5) was used to estimate impacts of oil and gas development on different crop types into the future. There would be a loss of different generalized crop types proportional to the overall acreage loss. Projected from the current conditions, within 25 years, approximately 52% of converted farmland would be orchards and vineyards, 38% would be row crops, less than 1% would be pasture or sod, and the remainder would be uncultivated.

The worst-case projection of 7,450 acres between 2015 and 2040 represents less than 1% of the total acreage of Farmland (828,973 acres) in Tier 2 (Table 4.2-16). Nonetheless, based on the importance of agricultural lands in Kern County and the San Joaquin Valley, this impact is considered significant.

The Mitigation, Monitoring, and Reporting Program (MMRP) (see the 2015 FEIR Chapter 12 [SREIR Volume 8]) included MM 4.2-1 for mitigation of impacts on Prime, Farmland of Statewide Importance, and/or Unique Farmland based on the amount of disturbance of the well construction and related site development. The text of this deleted mitigation measure is as follows:

(2015 FEIR) **MM 4.2-1.** ~~For future oil and gas exploration and extraction activities that are: 1) on land designated Prime, Farmland of Statewide Importance or Unique Farmland; and 2) that have been actively farmed 5 years or more out of the last 10 years, agricultural land mitigation is required at a ratio of 1 to 1. The 1 to 1 ratio is applied to actual ground disturbance area for oil and gas activities (inclusive of temporary construction and permanent operational impact areas), but excludes non-farmed existing areas such as roads, and tank and maintenance areas, and lands for which agricultural mitigation has previously been provided at a 1 to 1 ratio. Prior to ground disturbing activity, the Applicant shall submit to the County written evidence of completion of one or more of the following measures to achieve this 1:1 mitigation ratio:~~

~~a. Funding and/or purchasing agricultural conservation easements or similar instrument acceptable to the County (to be managed and maintained by an appropriate entity).~~

~~b. Purchasing of credits for conservation of agricultural lands from an established agricultural farmland mitigation bank or an equivalent agricultural farmland preservation program managed by the County.~~

~~c. Restoring agricultural lands to productive use through the removal of legacy oil and gas production equipment, including well abandonment and removal of surface equipment.~~

~~d. Participating in any agricultural land mitigation program adopted by Kern County that provides equal or more effective mitigation than the measures listed above.~~

~~Mitigation lands shall meet the definition of Prime Farmland, Farmland of Statewide Importance, and/or Unique Farmland, and be of similar or higher agricultural quality as the lands, as established by the California Department of Conservation. Completion of the selected measure or, with the Kern County Planning and Community Development Director's approval, a combination of measures, are to occur on qualifying land in Kern County. If qualifying lands cannot be found in Kern County, upon written application to the County, the mitigation lands may be located within the San Joaquin Valley (San Joaquin, Stanislaus, Merced, Fresno, Madera, Kings, Tulare, or Kern County) or outside the San Joaquin Valley with written evidence that the same or equivalent crops can be produced on the mitigation land.~~

The 2015 FEIR determined that implementation of MM 4.2-1 would reduce this significant impact to a less than significant level. However, mitigation must have a legal basis for imposition to determine its effectiveness for reducing an impact, and the acquisition of an agricultural easement has been deemed by the court *of appeal* to not create new farmland and therefore does not replace the loss of the farmland activity due to the well construction. *As the court of appeal concluded, in discussing MM 4.2-1.a providing for mitigation by agricultural conservation easement:*

> *Entering into a binding agricultural conservation easement does not create new agricultural land to replace the agricultural land being converted to other uses. Instead, an agricultural conservation easement merely prevents the future conversion of the agricultural land subject to the easement. Because the easement does not offset the loss of agricultural land (in whole or in part), the easement does not reduce a project's impact on agricultural land. The absence of any offset means a project's significant impact on agricultural land would remain significant after the implementation of the agricultural conservation easement. Restating this conclusion using the data from this case, the implementation of agricultural conservation easements for the 289 acres of agricultural land estimated to be converted each year would not change the net effect of the annual conversions. At the end of each year, there would be 289 fewer acres of agricultural land in Kern County. Accordingly, under the thresholds of significance listed in the EIR, this yearly impact would qualify as a significant environmental effect. Slip Opin., pp. 80-81 (footnotes omitted).*

CEQA requires that even significant and unavoidable impacts must be mitigated to the extent feasible. However, based on the court's analysis, it is not possible to reduce a project's impact on agricultural land by requiring a conservation easement because such easements do not offset the loss of agricultural land in whole or in part. Accordingly, conservation easements do not provide an effective means of even partial mitigation for agricultural conversion impacts.

The court also concluded that MM 4.2-1.b, allowing purchase of credits for conservation of agricultural lands from an established agricultural farmland mitigation bank or equivalent program, and MM 4.2-1.d, allowing participation in an agricultural land mitigation program adopted by the County "that provides equal or more effective mitigation" compared to the first three measures, did not provide effective mitigation for the Project's conversion of agricultural land. The court found that no such programs currently exist, and, if they did, like the conservation easements in MM 4.2-1.a, such programs would not actually offset the Applicant's conversion of agricultural land. (As noted below, although MM 4.2-1.c regarding legacy equipment has also been deleted, a new mitigation measure regarding legacy equipment has been added.)

A number of jurisdictions such as San Joaquin County, Stanislaus County, and Yolo County, and the Cities of Davis, Livermore, and Stockton, have adopted General or Specific Plan policies or zoning code provisions, as exercises of their police power, that require agricultural conservation easements as a condition of development that converts agricultural land. However, Kern County has not done so. In any case, because the court of appeal rejected MM 4.2-1 in the 2015 FEIR and concluded that agricultural conservation easements do not offset the loss of agricultural land in whole or in part, and therefore do not reduce a project's impact on agricultural land, MM 4.2-1 that was originally in the 2015 FEIR has been deleted as a CEQA mitigation measure in this SREIR (October 2020).

~~*As a result of this change, this SREIR determines that there is no feasible mitigation that can reduce Project impacts to prime farmland, unique farmland, and farmland of statewide importation (Impact 4.2-1), or reduce Project impacts that could convert agricultural land to non-agricultural use (Impact 4.2-5) to a less than significant level.*~~

In response to comments on the SREIR (August 2020), this SREIR (October 2020) adds the following MM 4.2-1.

MM. 4.2.-1 (NEW)

For Oil and Gas Conformity Reviews that are 1) on land designated Prime, Farmland of Statewide Importance, or Unique Farmland; and 2) that have been actively farmed five years or more out of the last 10 years; and 3) have a water allocation sufficient for farming from any source shall have the following siting requirements:

A. *All Oil and Gas Conformity Reviews permitted after 2021 shall have a site plan that contains no more than the following area limitations per well. All storage, parking, and oil activities shall be conducted only on the approved site plan acreage.*

Subarea	***Acreage (Gross)***
Western	*2.0*
Central	*3.0*
Eastern	*1.2*

B. *No permit for a new well shall be issued if the applicant has legacy unused oil and gas equipment on the same legal parcel. The legacy oil and gas equipment shall be removed inclusive of compliance with applicable legal requirements (e.g., well plugging and abandonment requirements under state or federal regulations), and restoration of the surface grade consistent with surrounding lands on the parcel completed before any new well activity can commence. A full plan and details of actions needed to remove the legacy equipment shall be submitted with the site plan, be shown on a detail of the site plan, and be a condition of the approved permit. For farmland parcels in Tier 1, when both the surface and minerals are owned by the applicant, this measure does not apply.*

C. *Siting and construction of new disposal ponds are prohibited.*

Capping the disturbance of defined agricultural land at between 1.2 and 3 acres, depending on the Subarea, will constrain oil and gas activities to a limited area, reducing the impact on agricultural use. This new mitigation measure is considered feasible based on the analysis of land disturbance presented in Appendix F of this SREIR. This new measure is conservative by capping land disturbance at the average per-well disturbance in each Subarea prior to the Ordinance, rather than allowing disturbance at individual sites to exceed the Subarea average. Moreover, with the addition of this new measure, the SREIR (October 2020) provides more stringent *mitigation than the 2015 FEIR, which did not include a mitigation measure capping the footprint of oil and gas activities on agricultural land.*

The new requirement to remove legacy equipment that is within the applicant's control from the same parcel of defined agricultural land is another feasible measure that partly offsets impacts of the applicant's activities. While MM 4.2-1.c in the 2015 FEIR provided an option of legacy equipment removal, the new mitigation measure in this SREIR (October 2020) is required of all applicants that own or control legacy equipment on the same parcel in all Tiers if the mineral and surface owners are different. In Tier 1, where oil is the predominant land use, and both the surface and the minerals are owned by the applicant, the predominant use of the land is not farmland but productive oil land that is also voluntarily used for agriculture. As the mineral owner at any time can cease leasing the land for agriculture and use it exclusively for oilfield production, the removal of legacy equipment does not promote the restoration of farmland. Finally, prohibiting the siting and construction of new disposal ponds on defined agricultural land is an entirely new mitigation measure that will further reduce the footprint of oil and gas activities. Sufficient disposal methods with current lined disposal ponds and injection methodology are available to ensure that processed water is disposed of properly. There is no evidence that removal of defined farmlands for siting of new disposal ponds would affect the regulatory disposal of processed water from current or future drilling.

Together these new mitigation measures provide reasonable and feasible mitigation that will reduce conversion of prime and unique farmland and farmland of statewide importance addressed under Impact 4.2-1.

Nevertheless, t~~T~~he Project would, in specific agricultural locations, remove soils used for row or tree crops and *when needed to* construct a well pad for extraction of oil and gas. The construction and operation phases have been described and the potential ground disturbance identified. The worst-case projection of 7,450 acres being removed between 2015 and 2040 has been based on anticipated conditions remaining the same for agricultural lands in Kern County. The ~~*current*~~ permitting from December 2015 to March 2020 actually affected 52 acres. Many factors will affect the future actual impact to agricultural lands from oil exploration and extraction.

The designation of Prime Farmland depends on it being cultivated four out of the five last years and having a supply of water to irrigate. Kern County has no natural dry farming outside of grazing land. Therefore, the conversion of agricultural land to vacant, non-farmable land is heavily dependent on water supply and commodity prices. Although conversion in other parts of California is threatened by urban growth, in Kern County the lack of water under the SGMA, General Plan policies, and the location of these specific lands in oil field areas all limit the threat from urban expansion. Rather, as discussed in Chapter 4.9, Hydrology and Water Quality and Chapter 4.17, Utilities and Service Systems, the required mandates of the SGMA limit the use of groundwater, and land is fallowed. In many cases, water districts are actually acquiring lands to intentionally fallow as a tool to implement the SGMA.

A discussion of the SGMA as a factor in the conversion of agricultural land is provided in Chapter 4.9, Hydrology and Water Quality and 4.17, Utilities and Service Systems of this SREIR. This analysis shows that the baseline projections used for potential conversion of agricultural land by the Project, as well as cumulative impacts, are conservative and are affected by other factors, such as commodity prices that are not the result of the Project.

The implementation of Groundwater Sustainability Plans in the valley basin, which is the location of the Project permitting, also limits the use of agricultural easements. Such easements, which are required to be in perpetuity and limit the use of the land to agriculture, depend on a supply of water. The SGMA legislation and resultant Groundwater Sustainability Plans provide limitations for individual farmers' management of their lands and disincentivize entering into agricultural easements that limit the use of the land. While *individual* land owners can continue to voluntarily enter into these easements *for agricultural uses that do not conflict with restrictions on groundwater use*, *over time this practice is likely to be affected on a County-wide basis as a result of the SGMA process. In any case,* the appeals court has determined that *conservation easements* ~~*they*~~ do not mitigate the loss of agricultural land under CEQA. Therefore *the 2015 FEIR* MM 4.2-1, which required 1:1 mitigation with an agricultural easement, has been deleted as not legally implementable or feasible mitigation.

It is important to note that *new MM 4.2-1 which includes a requirement for applicants who own or control unused legacy equipment on the same parcel to remove that equipment, replaces the removal option that formerly was part* ~~*the removal of MM 4.2 -1 included the removal*~~ of MM 4.2-1C, which included a provision for oil operators to comply with the mitigation by "restoring agricultural lands to productive use through the removal of legacy oil and gas production equipment, including well abandonment and removal of surface equipment." This was part of an option in the mitigation measure that to date has not been utilized. Making this requirement a mandatory mitigation measure *is feasible where* ~~*assumes that*~~ there is legacy equipment on the surface owner's property that the applicant for the permit *owns or* controls ~~*that equipment*~~. If the existing equipment is owned or controlled by another operator, the complicated process that would be involved, including the refusal of the other operator to sell the interest, would delay or even completely obstruct the mineral owner's dominant right to access the minerals. The property rights of the owners of the idle wells or an existing tank farm are established through state law and regulated by the California Geologic Energy Management Division (CalGEM) permitting and enforcement system and not by the County. This state law includes Assembly Bill 2729 and Senate Bill 724 and new related CalGEM regulations, all of which were adopted and became effective after certification of the 2015 FEIR and impose significant new requirements on the planning, long-term management, and removal of legacy oil and gas production equipment as overseen by CalGEM. *While state law and regulations do not preempt a local measure requiring operators to remove their own legacy equipment, operators cannot feasibly comply with these requirements for legacy equipment that they do not own or control.* Therefore, the legal connection (nexus) and the legal authority to require *operators who do not own or control* such legacy equipment *to remove the equipment and* ~~*removal*~~ to return agricultural land back to the surface owner as a mandatory condition of receiving a County permit is beyond the County's authority.

Mitigation to require that wells be located in a specific limited area on agricultural operations (i.e., clustering) has been considered but is rejected. Mitigation that would require wells to be clustered or grouped on agricultural land *in all instances, regardless of the preference of individual surface and mineral owners,* is not *reasonable or* feasible.

*M*ineral rights are distinct from surface rights—i.e., the ownership of and right to the use the surface of the land for residential, agricultural, recreational, commercial, or other purposes. A mineral right is also an interest in real property and may be sold, transferred, leased, or retained separately from the surface rights, in which case the mineral rights are said to "severed," creating a split estate. In addition to the activities that occur in the subsurface, petroleum exploration and extraction involves the use of the surface for the establishment of well drilling and associated activities. Although the land overlying an oil and gas reservoir (the minerals) may have other surface uses (e.g., commercial businesses or residences), the oil or gas operator has a legal right to access the minerals and is entitled to extract them from the surface. Moreover, unlike the surface owner, who is subject to the Subdivision Map Act, which stipulates that ownership by multiple people of one parcel limits them all to act in agreement (i.e., cannot finance or sell a portion of a piece of property), mineral leases are exempt from those requirements and one legal lot of agricultural land could have *multiple* ~~*dozens of*~~ distinct ownership subsurface leases across the property. Each party has a legal right to access the surface and drill and extract the minerals.

If clustering were required to mitigate Project impacts to agricultural lands, the owners of mineral rights underlying agricultural lands would be forced to access such minerals from adjacent lands were clustering occurs but which does not overlie the mineral deposits owned by the well permittee that underlie the avoided agricultural lands. This would entail the use of directional and horizontal drilling techniques.~~, which~~

In some portions of Kern County, minerals are deposited in relatively homogeneous horizontal layers over a large area, so that the drill bore can gradually be deviated laterally to access the formation, without hitting traps or targeting small pockets of oil. Locations with this type of geology include the Wasco area as illustrated in Hughes (2020). In those regions, horizontal drilling from larger clustered well pads is routinely utilized by agreement among surface and mineral owners. However, even where the geology is suitable for horizontal drilling, individual farmers may prefer that wells be distributed in multiple locations on the property rather than clustered on a larger pad in a single location. It is not necessarily the case that clustering would protect the most valuable farmland, or that productive use of agricultural land is best served by clustering wells in one location within each legal parcel. In order to reach resources by drilling out from a central well pad, the pad may need to be located in an area of higher or potentially higher crop productivity within the parcel. There may be less productive areas for farming distributed in several locations throughout a given parcel, due to variations in soil quality, water supply, slope, drainage, access for farm equipment, past uses of the property and other factors. In addition, the most productive areas within a parcel may be different for different crops. The most effective cultivation practices for a given parcel and its crop or crops may not require one uninterrupted contiguous field. Consolidating wells on a larger well pad may constitute a greater physical barrier on a given parcel, while dispersed smaller well pads would be less obstructive, similar to the ponds, ditches, tree lines and other surface features that farmers routinely accommodate. The individual farmers are best able to identify the most agriculturally productive configuration of uses on split estate lands. Imposing a uniform configuration of wells on split *estate farmlands would constrain farmers' agricultural practices and ability to utilize their most valuable land in the most effective manner.*

As described in Chapter 3, Project Description, the Ordinance provides a two-track process when permitting activities on "split estate" lands—that is, lands in which different parties own the surface and mineral rights. Following the statutory 30-day notice period required by Civil Code Section 848 (or a shorter period, if waived by the surface owner), if the mineral and surface owner reach agreement and the surface owner signs the Site Plan submitted with the Oil and Gas Conformity Review application, expedited review of the application will take place within seven business days. If the application is deemed incomplete and additional information is requested, the second review will take place within three business days upon receipt of the requested information. If the surface owner declines to sign the Site Plan, applications for oil and gas activities will be subject to a minimum processing time of 120 days, including the pre-application notification process under Section 848 (30 days), a mandatory first site plan review (30 days) during which the surface owner has the opportunity to meet and discuss the Site Plan with County staff, a mandatory second site plan review (30 days), and a minimum permit approval waiting period of 30 days. If additional site plan reviews are required, each would extend for at least a mandatory 30-day period. This extended timeline allows consultation between surface owner and applicant, and provides the applicant with significant incentives to negotiate and obtain the surface owner's agreement to sign the Site Plan. If at any time during the process, the signature is obtained, the application immediately goes to the streamlined seven day review process.

The two-track application review process significantly enhances the negotiating position of a split estate surface owner relative to the mineral estate owner compared with existing state law in which the mineral estate is dominant. The process also gives the surface and mineral owner the opportunity and incentive to address, among other issues, the location of surface disturbance so as to lessen the impact on the agricultural use of the individual property. On parcels where the underlying geology is amenable to accessing mineral resources by horizontal drilling from wells not located directly above the resource (as discussed in greater detail below), the surface owner and mineral owner may agree that wells should be clustered within one area of the parcel, to leave the remainder available for agricultural use. Requiring clustering in all cases would deprive surface owners of the flexibility to negotiate their preferred use of the surface with mineral owners. That "one size fits all" approach is inconsistent with the purpose of the two-track application review process to facilitate agreement between surface and mineral owners.

In addition to being contrary to the two-track process for facilitating agreement, a one-size-fits-all clustering requirement is not appropriate because it would be infeasible in large parts of Kern County. In much of the County, extensive horizontal drilling may not be technologically or economically feasible, depending on geologic conditions. As explained in Appendix U of the 2015 FEIR (SREIR Volume 4), faulting and folding in Kern County has created more complex geometry with less lateral continuity than in most other oil and gas plays. In the Project Area, most reservoirs are contained within highly complex geologic settings that vary greatly, as detailed in the 2105 FEIR.

Multi-well pads are widely utilized in other oil and gas jurisdictions in the United States, including the Permian Basin of west Texas and southwest New Mexico, the Bakken Play of North Dakota and the Niobrara Play of Colorado. In these regions, geological formations are more homogeneous and producible reservoirs are laid out in flat and long intervals. In addition, there are few operating Enhanced Oil Recovery (EOR) projects in these areas.

By contrast, formations in California, including Kern County, are largely dominated with faults and traps that do not allow clustering wells because the producible reservoirs are pinched out and discontinuous laterally. Reservoir geometry is often modified by complex structural environments where faulting creates isolated "rooms" within the geometry of the containing structure. This can be likened to a pane of glass that has been broken into various-sized pieces and trying to place the well on the smallest piece of glass on the bottom of a 10 layer stack of glass pieces. Additionally, while reservoir geometry is complicated by structural overprinting, the reservoir characteristic, notably porosity and correspondingly permeability, is controlled by subtle differences in the lithology of the rock matrix. This added complexity serves to greatly complicate the design of a well drilling and completion program and requires flexibility in well design and drilling technique to provide safe, environmentally sound, and efficient oil production. *Moreover, EOR, which is common in Kern County, imposes functional constraints on well spacing. When EOR methods such as steam flooding and water flooding are used, precise well spacing is dictated by the need to mobilize and collect hydrocarbons from production wells surrounding the injection well. Reconfiguring the distribution of EOR wells in tighter clusters is technologically infeasible. Moreover, EOR is used primarily in older fields such as in Lost Hills, Belridge, and other fields with shallow reservoirs, some of which contain agricultural land. Clustering wells is not geometrically feasible at a shallow target depth that would require sharp turns both vertically and horizontally to reconfigure EOR wells. In addition to the technical infeasibility of achieving effective EOR patterns, excessively sharp curves increase the probability of casing failure due to frictional heat and side loading.*

Accordingly, a mitigation measure that requires d~~D~~rilling only horizontal wells in order to access the *reserves* ~~geologic structures~~ beneath agricultural lands that lie beyond the clustered well pad*, regardless of whether the underlying geologic structures are suitable for horizontal drilling,* substantially limits the feasibility of the drilling program and securing the optimal completion geometry.

Genuinely horizontal drilling remains relatively rare in Kern County, consistent with the widespread complex geological structures that are typically unfavorable. For this purpose, directional drilling that is only slightly deviated from vertical must be distinguished from horizontal drilling that extends laterally. Moreover, drilling equipment is not capable of making near-right angle turns from the vertical initiation of the bore to a horizontal or near-horizontal orientation. Even where the geology is amenable to drilling laterally, a well must be deep enough to accommodate a gradual horizontal turn.

In a dataset of wells drilled in the County in 2020, only 7% were drilled horizontally, while 76% were drilled directionally and 17% vertically (Hughes 2020). The angle of deviation of those categories was not reported. However, in a dataset of 9,803 wells drilled from 2000 to 2020 by *the California Resources Corporation (CRC), the largest operator on split estate lands in Kern County, 44% were drilled vertically, 46% directionally, and 10% horizontally. The average inclination for CRC's vertical and directional wells was 10.8 degrees and 18.3 degrees, respectively, compared to an average inclination of 82.09 degrees for horizontal wells capable of reaching laterally distributed resources. Fifty-three percent of the directional wells had an inclination of less than 20 degrees. The small deviation from vertical in the category of directional wells is mainly driven by geological constraints and reservoir configurations that are laterally discontinuous. Accordingly, such directional wells are properly considered as distinct from the laterally deviating horizontal wells that can reach more distant resources.*

A proposed mitigation measure that requires clustering can be expected to reduce the footprint of consolidated multi-well pads using common access roads and infrastructure, compared to the sum of the footprints of dispersed well pads with separate access roads and infrastructure. In addition to impacting fewer acres of agricultural land, clustering could also benefit wildlife species that co-exist with agricultural uses. Use of multi-well pads and common infrastructure can reduce construction time and cost. However, these incremental benefits from clustering mitigation may be reduced by other existing mitigation measures and incentives. Most future oil and gas production in Kern County is expected to occur in established oil fields that are many decades old, are already highly disturbed, and have well-developed infrastructure and access roads already in place. For efficiency, operators utilize existing access roads when available to connect to new pads, thus reducing surface disturbance. Furthermore, MM 4.1-4 requires applicants to use existing public access easements or County-maintained roads to access oil production areas, allowing new roads only if there is no existing public access easement or permission cannot be obtained to use an existing private access easement or private driveway/road. MM 4.2-2.h requires that overhead electrical or communication lines must be aligned with existing roads, existing lines and easements, existing private driveways, and/or parallel to tree or row crops. In addition, new MM 4.2-1, introduced in this SREIR (October 2020), caps the amount of land disturbance for new wells at 2.0 acres in the Western Subarea, 3.0 acres in the Central Subarea, and 1.2 acres in the Eastern Subarea.

A mitigation measuring mandating the clustering of wells is reasonably expected to require horizontal drilling that would require longer drilling periods to reach the mineral source as compared to a vertical well. This would cause environmental impacts that are potentially greater than would occur if the drilling was allowed vertically on the agricultural land to begin with. *While there would be some reduction of emissions associated with constructing fewer access roads, as noted above, most future oil and gas production in Kern County is expected to occur in established oil fields with access roads already in place, where the primary effect on emissions will be from incremental horizontal drilling.* Longer drilling periods mean increased levels of construction-related emissions*, while emissions from later phases of a well's productive life would be unchanged*. *Horizontal drilling not only requires longer drilling times, which increase emissions, but also tends to require greater power. Operation of larger, higher horsepower engines for horizontal drilling results in higher emissions than vertical drilling for an equivalent distance. Moreover, the engines utilized in drilling operations come in discrete sizes. As a result, transitioning to the next larger size of engine, in order to achieve a given increase in power, may result in a disproportionate increase in emissions. Well pad preparation and construction* *emissions are negligible compared to emissions from drilling and primarily consist of PM_{10}. Therefore, consolidating wells on a single pad rather than separate pads would have little effect on overall emissions and, in particular, would not reduce NO_X emissions. Thus, while a well clustering mitigation requirement would have the benefit of impacting fewer acres of agricultural land, it is reasonably expected to contribute to the cumulative overall emissions of criteria pollutants for which the air basin is in nonattainment.*

Furthermore, mandatory well clustering would increase the potential for injury on and around the clustered well pad, increase traffic and related air emissions, and intensify the habitat disruption posed by densely clustered well drilling pads that may be necessary to conduct both horizontal and vertical drilling operations. ~~*Thus, while a well clustering mitigation requirement would have the benefit of impacting fewer acres of agricultural land, it is reasonably expected to exacerbate overall emissions of criteria pollutants for which the air basin is in nonattainment and, in some cases a*~~ *Overlapping drilling, completion, and facility operations requires simultaneous operation of equipment, including drilling rigs, completion rigs, construction cranes, and heavy trucks and loaders, as well as increased personnel traffic, within a confined area on and around multi-well pads. Drilling laterally from a multi-well pad in a location with highly faulted geology under tectonic stress can also expose operations to greater risk. Penetrating unstable formations at the incorrect angle can lead to borehole breakout with a potential unplanned sidetrack and/or loss of the well. The higher density of activity may reduce the footprint, but also increase the risk and potential magnitude of incidents resulting in disturbance to lands and habitat, compared to dispersed activities at single well pads. A* clustering mitigation measure *c*~~*w*~~ould cause *greater* land disturbance impacts to relatively undisturbed land cover types ~~*as compared to*~~ *than in* adjacent agriculturally productive land, ~~*in*~~ which ~~*case such a measure*~~ could result in additional impacts to biological resources that would not occur if the well operator were permitted to access agricultural land for vertical drilling purposes. Accordingly, a mitigation measure requiring well clustering would not be effective in reducing, and is reasonably likely to exacerbate, the Project's overall adverse effects and is therefore infeasible.

California has long held that the owner of a mineral interest "has a property right in oil and gas beneath the surface" that includes "the exclusive right to drill[.] … This is a right which is as much entitled to protection as the property itself, and an undue restriction of the use thereof is as much a taking for constitutional purposes as appropriating it or destroying it." Bernstein v. Bush (1947) 29 Cal.2d 773, 778 (internal cites omitted). Also, a mineral owner's right of entry onto the surface estate for drilling purposes is a property right incident to the grant of a mineral estate and exists even without an express grant. *Callhan v. Grant* (1935) 3 Cal.2d 110, 125-26; *Dabney-Johnston Oil Copr. V. Walden* (1935) 4 Cal.2d 636, 649. Given the unconventional geology of the Project Area, it is also reasonable to assume that, in some instances, the owners of mineral interests underlying agriculturally productive lands will not be able to feasibly exercise their mineral rights or their access rights as a result of a mitigation measure that mandates well clustering, which would cause a compensable taking of private property under the state and federal constitutions.

By severing and selling a mineral interest or granting a mineral lease, surface owners have implicitly granted a right of entry onto the surface land. There is no authority by the County to deny this pre-existing right, already held by the mineral owner, by conditioning a permit on a specific location on the site that could limit other mineral users. Further, such a limitation by the County could be a potential "taking" of the mineral interest rights and contrary to the CEQA provision of rough proportionality.

Many mineral leaseholds in Kern County are modest in size, limiting the quantity of resources that can be accessed by horizontal drilling across a single parcel. For example, the distribution of lease sizes in Kern County for California Resources Corporation is shown in Table 4.2-18. Over half of the mineral leases are less than 40 acres in size, and 20% of the leases are less than 20 acres, while only 7.26% are 640 acres or greater.

Table 4.2-18: Mineral Lease Sizes

Mineral Lease Size (Acres)	***# Leases***	***% of Total***
640 and greater	*468*	*7.26*
320 – 639.9	*501*	*7.77*
160 – 319.9	*945*	*14.66*
80 – 159.9	*1,208*	*18.73*
40 – 79.9	*1,226*	*19.01*
20 – 39.9	*750*	*11.63*
< 20	*1,350*	*20.93*

Source: California Resources Corporation

In addition, while Kern County Assessor Office's data show only one producing mineral owner on each lease for property tax purposes, it is the exception, not the rule, to have only one record title owner in a mineral tract. Nearly all mineral rights in Kern County are owned by at least two or more mineral owners. Many mineral tracts in the County have more than one record title holder owning various percentages of the mineral rights, and some tracts have hundreds of fractional owners, which may be stratified vertically as well as horizontally. The complexities of fractional ownership, as well as fractured geology dominated with faults, traps, and pockets of oil, preclude simply drilling straight through from one end to the other of a series of parcels and interests that may appear under one company's name as a common "mineral tenure" based on the tax rolls.

A mineral owner's legal right under state law to use the surface estate to access minerals does not extend to mineral estates on other lands. In order to drill from the surface of tract A to reach minerals in tract B, the tract B mineral owner must obtain the permission of the tract A surface owner. Without permission, the tract B mineral owner has no right of entry and the use of the tract A surface is a trespass. Even if the mineral lessee is the same in both tracts A and B, the fact that there is a common lessee of adjacent or nearby tracts is not sufficient under the law to allow drilling from one tract into the other. The mineral owner's right to use the surface of tract A is limited to the amount of tract A surface that is reasonably necessary for production from tract A, and constructing a larger well pad on tract A to accommodate horizontal drilling into tract B could exceed the reasonable use of tract A (Mills 2020.) Clustering could not be accomplished without securing the necessary rights from all parties in leaseholds, which may be highly complex. It is *likely that some mineral owners will be unable to secure all necessary rights to legally produce their minerals from other parcels, potentially exposing the County to liability for takings.*

The surface owner of the affected active agricultural land is compensated for damage and removal of crops by the mineral holder and can use that funding to plant more crops, improve the productivity of the same lands through water efficiencies, or buy other land to farm. The County process for agricultural lands that are not owned in Tier 2 lands by the mineral owner provides for a 120-day process for the parties to review and discuss the site plan. This process provides an opportunity to locate the surface disturbance to lessen the impact on the agricultural use of the property. *Agricultural parcels have areas that are not planted or that are unsuitable for planting and could become a better oil drilling site during these discussions. Clustering would require that an entire consolidated area, which may actually be a productive area, be used when scattered sites are better for the farm operation.* Further, MM 4.1-1 in *Section 4.1, Aesthetics* also limits the location of the new well on the property as access must be from existing roads, either public or private, which shapes the location of the wells.

There is no *additional* feasible, reasonable, or legal mitigation for the loss of productive agricultural land *that could mitigate this impact to a less than significant level.*~~, and t~~ *T*his impact remains significant and unavoidable *with the required mitigation in MM 4.2-1.*

Mitigation Measures

~~*No feasible mitigation is available to reduce this impact to a less than significant level.*~~

MM 4.2-1. For Oil and Gas Conformity Reviews that are 1) on land designated Prime, Farmland of Statewide Importance or Unique Farmland; and 2) that have been actively farmed five years or more out of the last 10 years; and 3) have a water allocation sufficient for farming from any source shall have the following siting requirements:

A. All Oil and Gas Conformity Reviews permitted after 2021 shall have a site plan that contains no more than the following area limitations per well. All storage, parking, and oil activities shall be conducted only on the approved site plan acreage.

Subarea	Acreage (Gross)
Western	2.0
Central	3.0
Eastern	1.2

B. No permit for a new well shall be issued if the applicant has legacy unused oil and gas equipment on the same legal parcel. The legacy oil and gas equipment shall be removed inclusive of compliance with applicable legal requirements (e.g., well plugging and abandonment requirements under state or federal regulations), and restoration of the surface grade consistent with surrounding lands on the parcel completed before any new well activity can commence. A full plan and details of actions needed to remove the legacy equipment shall be submitted with the site plan, be shown on a detail of the site plan, and be a condition of the approved permit. For farmland parcels in Tier 1 when both the surface and minerals are owned by the applicant, this measure does not apply.

C. Siting and construction of new disposal ponds are prohibited.

Level of Significance After Mitigation

Impacts would be significant and unavoidable.

Impact 4.2-2: Conflict with Existing Zoning for Agricultural Use or a Williamson Act Contract

The Project's potential to conflict with existing zoning for agricultural use or a Williamson Act contract was assessed in the 2015 FEIR (SREIR Volume 3).

Mitigation Measures

No mitigation measures are required.

Level of Significance

Impacts would be less than significant.

Impact 4.2-3: Conflict with Existing Zoning for, or Cause Rezoning of, Forest Land or Timberland

The Project's potential to conflict with existing zoning for, or cause rezoning of, forest land or timberland was assessed in Section 4.2 of the 2015 FEIR (SREIR Volume 3.)

Mitigation Measures

No mitigation measures are required.

Level of Significance

The Project would result in no impacts to zoning for forest land or timberland.

Impact 4.2-4: Result in the Loss of Forest Land or Conversion of Forest Land to Non-Forest Use

The Project's potential to result in the loss of forest land or conversion of forest land to non-forest use was assessed in Section 4.2 of the 2015 FEIR (SREIR Volume 3).

Mitigation Measures

No mitigation measures are required.

Level of Significance

The Project would result in no impacts to forest land or the conversion of forest land to non-forest use.

Impact 4.2-5: Involve Other Changes in the Existing Environment which, Because of Their Location or Nature, Could Result in Conversion of Farmland to Non-Agricultural Use or Conversion of Forest Land to Non-forest Use

Future oil and gas exploration and production activities that would be authorized under the proposed Project would involve drilling of approximately 2,700 new oil or gas wells annually, as well as other ancillary facilities, including pipelines, electrical distribution lines, temporary pits, percolation ponds, sumps, and central processing facilities.

Although Kern County zoning considers oil and gas and agriculture as compatible land uses, certain agricultural practices and portions of the oil and gas production cycle, if conducted in close proximity, would not be compatible and would have direct impacts. Fragmentation of farmland into smaller field sizes could make it difficult for farmers to operate certain types of equipment that are necessary to their planting, production, and harvest operations, or to viably produce certain types of crops. Oil and gas development within agricultural lands could also disrupt irrigation or field drainage systems (see Figure 4.2-8). Truck traffic could generate dust, which could harm the photosynthetic processes of plants and potentially cause localized damage to fruit, vegetables, and greens. Row crops could most readily be adjusted to farm plot size and configuration, but removal of orchard trees or supported vines that take years to reach productive maturity may not be as adaptable to changes and, therefore, this impact is considered significant.

Clearing and grading involved with construction of access roads and well pad construction would disturb the agricultural soil and potentially mix topsoil and subsoil, and create dust. Use of heavy equipment, including trucks, and tanks used during oil and gas production activities would result in soil compaction beneath roads leading to well pad areas.

Temporary pits and sumps that collect non-hazardous drilling fluids, wellbore cuttings, drilling wastes, crude oil, or produced water may increase the risk of exposure of agricultural soils to potentially hazardous chemicals and materials. Drilling pits and sumps are subject to requirements to prevent potential impacts to groundwater, under the State Water Resources Control Board's Statewide General Order (No. 2003-0003-DWQ) for low-threat discharges to land or Waste Discharge Requirements issued by the Central Valley Regional Water Quality Control Board. In most cases, drilling sumps are not permitted on agricultural lands and a closed-loop system is used instead. Produced water impoundments are also regulated by the state and generally will not be permitted on agricultural lands. Produced water that contains concentrations of constituents that exceed water quality objectives must be constructed in locations where site characteristics and containment structures isolate wastes from waters of the state (see Section 4.9, Hydrology and Water Quality, for further details). Nevertheless, there could be a potential for spills during the process of removing operations fluids from sumps and, therefore, significant impacts.

Indirect impacts of oil and gas activities on adjacent FMMP land could include dust from truck traffic, soil erosion from graded areas, and sedimentation onto agricultural land, and accidental releases of hazardous materials.

Impacts from the use of the surface for oil exploration and extraction, which is a property right by mineral leases, could impact the ability of surface lands to be used for agriculture and accelerate the conversion of an area from primarily agricultural to a dominate oilfield use. MM 4.2-2 (~~*numbered MM 4.2-2 in the 2015 FEIR)*~~ will protect crops and structures adjacent to oil and gas activities but cannot override the mineral interest right to drill. The surface owner of the affected active agricultural land is compensated for damage and removal of crops by the mineral holder and can use that funding to plant more crops, improve the productivity of the same lands through water efficiencies, or buy other land to farm. The County process for agricultural lands that are not owned by the mineral owner provides for a 120-day process for the parties to review and discuss the site plan. This process provides an opportunity to locate the surface disturbance to lessen the impact on the agricultural use of the property. Further, MM 4.1-1 *in Section 4.1, Aesthetics* also limits the location of the new well on the property as access must be from existing roads, either public or private which shapes the location of the wells.

MM. 4.2-2 (formerly 4.2-2 in the 2015 FEIR~~-~~*and 4.2-1 in the SREIR (August 2020~~-~~)* has been clarified for specific implementation actions.

MM 4.2-2 To protect crops and structures adjacent to oil and gas activities on active agricultural lands, each Applicant/operator shall comply with the following mitigation measures set forth in other chapters of this Environmental Impact Report:

a. Surface water runoff and drainage on the well pads shall be mitigated as described in mitigation measures for Hydrology and Water Quality.

b. A Spill Prevention Countermeasure and Contingency Plan or Division of Oil Gas and Geothermal Resources Assembly Bill 1960 spill plan, as applicable, shall be prepared for the site and oil and chemical spills treated in accordance with the Division of Oil Gas and Geothermal Resources Senate Bill 4 Regulations for the site to protect adjacent farmland, as described in mitigation measures for Hazards.

c. Speed limits for oil and gas trucks shall be posted on unpaved roads to reduce dust generation; in the absence of signage, speed limits shall be limited to 25 miles per hour (or an alternate, more stringent dust suppression standard as adopted by the San Joaquin Valley Air Pollution Control District), and Applicants shall attest that employees have been trained in the adopted ~~appropriate~~ speed limits.

d. Unpaved roads shall be watered or otherwise treated for dust suppression and control as described in Mitigation Measure for Air Quality, unless speeds are restricted to 15 mph.

e. Vehicle tracking control shall be installed where unpaved roads intersect with public paved roads, to prevent tracking of mud, dust, and weed seeds off site, unless speeds are restricted to 15 mph. This shall consist of a 50-foot length of a 3 inch-thick layer of gravel one inch or larger in diameter (or an alternate, more stringent dust suppression technique as approved by the San Joaquin Valley Air Pollution Control District).

f. Stormwater control shall be required at construction sites during well drilling, reworking, and/or decommissioning as described in mitigation measures for Hydrology.

g. Hazardous materials shall be stored within secondary containment as described in mitigation measures for Hazards.

h. Overhead electrical or communication lines shall be shown on the Site Plan, and shall be aligned ~~to the greatest extent feasible~~ with existing ~~access~~ roads, existing lines and easements, existing private driveways and/or parallel to tree or row crops. ~~and the minimum distance between the access road and the well installation or other oil and gas facility, parallel to tree or row crops, described further in mitigation measures for Public Utilities. If the use of existing roads is not feasible, lines shall be routed to minimize surface disturbance and minimize the impacts to surface activity~~ Underground pipelines serving the Project shall be shown on the Site Plan with locations marked and recorded with USAA, and periodically inspected and maintained as described in mitigation measures for Hazards.

There is no additional feasible, reasonable, or legal mitigation that could mitigate impacts on adjacent and surrounding agricultural areas from oil and gas exploration and extraction activities to a less than significant level. This impact is significant and unavoidable with the required mitigation in MM 4.2.-1 and MM 4.2-2.

Mitigation Measures

MM 4.2-2. To protect crops and structures adjacent to oil and gas activities on active agricultural lands, each Applicant/operator shall comply with the following mitigation measures set forth in other chapters of this Environmental Impact Report:

a. Surface water runoff and drainage on the well pads shall be mitigated as described in mitigation measures for Hydrology and Water Quality.

b. A Spill Prevention Countermeasure and Contingency Plan or Division of Oil Gas and Geothermal Resources Assembly Bill 1960 spill plan, as applicable, shall be prepared for the site and oil and chemical spills treated in accordance with the Division of Oil Gas and Geothermal Resources Senate Bill 4 Regulations for the site to protect adjacent farmland, as described in mitigation measures for Hazards.

c. Speed limits for oil and gas trucks shall be posted on unpaved roads to reduce dust generation; in the absence of signage, speed limits shall be limited to 25 miles per hour (or an alternate, more stringent dust suppression standard as adopted by the San Joaquin Valley Air Pollution Control District), and Applicants shall attest that employees have been trained in the adopted speed limits.

d. Unpaved roads shall be watered or otherwise treated for dust suppression and control as described in Mitigation Measure for Air Quality, unless speeds are restricted to 15 mph.

e. Vehicle tracking control shall be installed where unpaved roads intersect with public paved roads, to prevent tracking of mud, dust, and weed seeds off site, unless speeds are restricted to 15 mph. This shall consist of a 50-foot length of a 3 inch-thick layer of gravel one inch or larger in diameter (or an alternate, more stringent dust suppression technique as approved by the San Joaquin Valley Air Pollution Control District).

f. Stormwater control shall be required at construction sites during well drilling, reworking, and/or decommissioning as described in mitigation measures for Hydrology.

g. Hazardous materials shall be stored within secondary containment as described in mitigation measures for Hazards.

h. Overhead electrical or communication lines shall be shown on the Site Plan, and shall be aligned with existing roads, existing lines and easements, existing private driveways and/or parallel to tree or row crops. Underground pipelines serving the Project shall be shown on the Site Plan with locations marked and recorded with USAA, and periodically inspected and maintained as described in mitigation measures for Hazards.

Level of Significance After Mitigation

Significant and unavoidable.

Impact 4.2-6: Result in the Cancellation of an Open Space Contract Made Pursuant to the California Land Conservation Act of 1965 or Farmland Security Zone Contract for Any Parcel of 100 or More Acres

The Project's potential to result in the cancellation of an open space contract made pursuant to the Williamson Act or FSZ contract for any parcel of 100 or more acres was assessed in the 2015 Section 4.2 of the 2015 FEIR (SREIR Volume 3).

Mitigation Measures

No mitigation measures are required.

Level of Significance

No impacts relating to cancellation of a Williamson Act or FSZ contract would occur.

Impact 4.2-7: Substantially decrease the productivity of livestock grazing activity within Kern County.

Table 4.2-1~~8~~9 summarizes the percentage of total acreage in each Tier and Project Subarea that is mapped as grazing land by the FMMP. The table excludes County non-jurisdictional and "other" land that is not subject to the Ordinance.

Table 4.2-1~~8~~9: Percentage of Total Acreage Mapped as Grazing Land by Tier and Subarea

Tier	Western Subarea	Central Subarea	Eastern Subarea
Tier 1	40.34%	35.44%	40.15%
Tier 2	60.19%	8.53%	63.46%
Tier 3	26.63%	17.21%	28.27%
Tier 4	56.00%	7.40%	27.54%
Tier 5	90.28%	0.00%	21.72%

Sources: SREIR Table 4.2-12 (above), 2018 SEIR Table 4-5 (SREIR Volume 8), and 2015 FEIR Table 4 4.-73 (SREIR Volume 3).

Table 4.2-~~19~~20 summarizes the annual and 25-year total acres of impacts to grazing land that could occur by Tier and Project Subarea based on the projected disturbed acres by Tier and Subarea shown in Tables 3-4 and 4.4-73 of the 2015 FEIR (SREIR Volume 3), and the incidence of mapped grazing land in each Tier and Subarea as shown in Table 4.2-1~~8~~9, above.

Table 4.2-~~19~~20: Potentially Annual and 25-year Grazing Land Impacts by Tier and Project Subarea

Potential Annual Grazing Land Acreage Impacts				
Tier	**Western Subarea**	**Central Subarea**	**Eastern Subarea**	**Total (sum of individual tier and subarea impacts)**
Tier 1	1,315	106	337	1,759
Tier 2	89	5	57	151
Tier 3	8	3	17	28
Tier 4	11	1	3	16
Tier 5	2	-	0	2
Total (sum of individual tier and subarea impacts)	**1,425**	**116**	**415**	**1,956**
Potential Grazing Land Acreage Impacts Over 25 Years				
Tier 1	32,877	2,659	8,431	43,967
Tier 2	2,227	128	1,428	3,783
Tier 3	200	77	424	701
Tier 4	280	28	83	390
Tier 5	45	-	5.4	51
Total (sum of individual tier and subarea impacts)	**35,629**	**2,892**	**10,371**	**48,891**

Sources: SREIR Table 4.2-1~~8~~9 (above) and 2015 FEIR Table 4-10 (SREIR Volume 3).

Table 4.2-~~19~~20 indicates that, using the projected disturbed acres in Table 4.4-71 of the 2015 FEIR (SREIR Volume 3) (which are based on the conservative disturbance factors set forth in the 2015 FEIR), the Project could impact up to 1,956 acres of grazing land per year, and 48,891 acres over the 25-year Project planning horizon. About 90% of these impacts would occur in Tier 1 portions of the Project Area and 84.5% would occur in Tier 1 portions of the Western Subarea and the Eastern Subarea. For the reasons discussed above, these estimates are highly conservative, both spatially and temporally. Since livestock may graze in close proximity to oil and gas operations as described above, grazing is likely to occur on a substantial number of acres included in the Project impact totals in Table 4.2-~~19~~20. Moreover, the totals in Table 4.2-~~19~~20 are based on the conservative assumption that all Project impacts to grazing are permanent, although, in fact, over the long term, areas of oil and gas development have been returned to conditions that facilitate livestock grazing.

The following sections discuss grazing activities in Tier 1 oil and gas areas in more detail.

Sheep Grazing in Tier 1 Locations

Sheep grazing occurs in Tier 1 locations throughout the Project Area, including the Eastern, Central, and Western Subareas. Grazing activity in Tier 1 areas usually peaks from November to April, when green vegetation is located at lower elevations in Kern County. Sheep operations subsequently shift to higher elevations, including to the Sierra Nevada range, as upland meadows and grasses become available after the spring thaw.

While there is variability in the size, scope, and duration of sheep grazing in Tier 1 areas, a typical flock consists of about 1,800 to 2,000 sheep. The size of grazing sites for a flock of this size varies considerably depending on available acreage and forage quality, but would be significantly less than required for a comparable number of cattle due to the greater grazing efficiency of sheep. Flocks are transported to each site by the sheepherder and typically remain for several weeks to two months, depending on the acreage leased. The sheepherder provides water for the flock, usually by means of an onsite water tank transported to the grazing location, and the sheepherder typically remains onsite in a trailer or recreational vehicle until grazing has been completed.

Sheep grazing in Tier 1 areas can occur in and among sites of oil operations, sometimes within 2 feet of operating oil field equipment, though typically avoiding heavily operated areas. The location of grazing flocks, and individual sheep within each flock, is effectively controlled by temporary fencing and herding animals. Once a flock has completed grazing at a specific location, the sheep are removed from the site by the sheepherder and transported to another site, including within other portions of Tier 1 areas, depending on the season and whether sufficient forage is available. The sheepherder will also remove and any temporary shelter from the completed grazing site. In a typical year, and subject to annual variability due to rainfall and weather, sheep grazing will largely be completed by June within the lower portions of the Project Area, and by August in Tier 1 lands located at higher elevations.

Cattle Grazing in Tier 1 Locations

Cattle grazing occurs year-round in Tier 1 locations throughout the Project Area, including the Eastern, Central, and Western Subareas. The number of cattle grazed varies with the supply and quality of forage at each location. Cattle are less efficient grazers and require substantially more foraging acreage than sheep. As a result, cattle are not typically moved to and managed to graze within smaller, temporarily delimited portions of Tier 1 areas for short periods of time in the manner of sheep flocks. Cattle grazing in and adjacent to Tier 1 areas typically occurs in larger areas that can be accessed by livestock during most or all of the year.

In certain instances, cattle ranching and oil and gas operations in Tier 1 areas jointly occur within the same landscape. Oil and gas operations, for example, have been developed within previously existing cattle ranches where both uses have persisted over time. As a result, in certain Tier 1 areas, cattle are free to graze and move in and among operating oil and gas equipment at all times of the year.

In other Tier 1 locations, cattle grazing occurs in close proximity to some of the most dense oil and gas operations in the Project Area, but access to the most heavily developed areas is controlled by fencing and cattle guards. Cattle grazing fence lines along the eastern flank of the Temblor Range in the Western Subarea, for example, extend into several major oil and gas development sites located in Tier 1 areas and come within a few feet of currently operating equipment. Similar proximity to operating oil and gas equipment occurs in other Tier 1 portions of the Project Area, including the South Hopkins, Salt Creek, McKittrick, Kern Front, Wheeler Ridge, and Mount Poso Administrative Oil Fields.

Existing oil and gas operations in certain Tier 1 locations have moved from adjacent areas that were heavily developed in prior periods. For example, portions of the Tier 1 lands located in the Elk Hills and Mount Poso Administrative Oil Fields were densely covered with oil and gas equipment several decades ago. These areas are currently grasslands that support forage for cattle grazing. As the location of primary oil and gas activities within certain Tier 1 areas gradually shifts over time, cattle grazing can occur in areas once heavily developed for oil and gas operations.

Trends in Grazing Land Use

The Kern County Agricultural Commissioner publishes an annual crop report for Kern County based on information provided by agricultural operators, including ranching operations, in the County. As of July, 2020, annual crop reports for each year during the period 1930 to 2016 were available online at http://www.kernag.com/caap/crop-reports/crop-reports.asp. The annual crop reports include an estimate of the acres of "range/pasture" in use during the reporting year as a line item in the "field crops" summary for Kern County. In 1987, for example, the crop report estimated that 2,083,000 acres of pasture/range were used in the field crop totals (Kern County Department of Agriculture and Measurement Standards 1987). In 2012, the crop report estimated that 1,479,000 acres of pasture/range were used and reported in the field crop totals for 2012 (Kern County Department of Agriculture and Measurement Standards 2012). Figure 4.2-9 shows the annual acreage of pasture/range reported in use in each Kern County crop report from 1981 to 2016.

The annual amount of rangeland in use reported in the Kern County crop reports significantly decreased in the 25 years prior to 2012. In the five years from 1987 to 1991, for example, an average of approximately 2,197,459 acres of rangeland per year was reported to be in use in Kern County compared with an annual average of 1,462,000 acres during 2012 to 2016. These data suggest that demand for rangeland in the County has decreased over time, possibly by over 700,000 acres in the last 25 years. By contrast, as shown in Table 4.2-1, the FMMP has estimated that total County grazing land increased by over 100,000 acres from 1988 to 2016. Thus, reported rangeland actually in use in the County since 2012 is substantially below the estimated supply of available grazing land in the FMMP data. In 2016, for example, Table 4.2-1 indicates that Kern County had over 1,849,000 acres meeting the FMMP criteria for grazing land. The pasture/range use reported in the 2016 crop report, was just 1,444,000 acres (Kern County Department of Agriculture and Measurement Standards 2016).

Trends in Livestock Grazing Productivity

The Kern County annual crop reports include estimates of the gross revenues or value received from livestock sales each year. As discussed above, cattle sales form a significant majority of all livestock income in the County, and cattle and sheep sales have collectively generated well over 90% of all livestock income over time. Figure 4.2-10 shows the annual amount of livestock value reported in each Kern County crop report from 1981 to 2016 in nominal (unadjusted) and inflation-adjusted amounts. The inflation-adjusted figures used constant 2009 dollars based on the California Consumer Price Index (DOF 2018).

The value of livestock in Kern County rose significantly from 1981 to 2016 in terms of both the nominal amounts reported in the annual crop reports and based on constant 2009 dollars using the Consumer Price Index. In the five years from 1987 to 1991, the average annual nominal value of livestock sales in Kern County was $43.4 million, compared with an annual average of $390.9 million in 2012 to 2016, a ninefold increase. Inflation-adjusted livestock value rose about 4.6 times from 76.2 million in 1987–1991 to 356.7 million in 2012–2016. These data show that, although reported rangeland use decreased over the last 25 years, and is currently well below the acreage of grazing land mapped by the FMMP for the County, livestock value generated by sales of cattle and sheep have substantially increased.

Figure 4.2-11 shows the percentage of total Kern County agricultural value reported in annual crop reports from 1981 to 2012 that is accounted for by the value of livestock sales. Over time, and subject to fluctuation, livestock sales have generally increased as a percentage of total County agricultural value.

In the five years from 1987 to 1991, livestock sales averaged about 2.7% of total Kern County agricultural value. During 2012 to 2016, livestock sales averaged 5.7% of total County agricultural value, more than double the prior rate. As shown in Table 4.2-2~~0~~1, the value of Kern County livestock also increased much more rapidly than the total value of Kern County agriculture from 1987 to 2012, using both nominal and inflation-adjusted data.

Table 4.2-2~~0~~1: Kern County Total Agricultural and Livestock Value, 1987 and 2012 Nominal and Constant 2009 (CPI) Dollars

	1987 nominal	**2012 nominal**	**Net Growth**	**Percent growth**
Total County Value	1,511,805,000	6,769,855,590	5,258,050,590	348%
Livestock Value	40,781,000	395,078,000	354,297,000	869%
	1987 (2009 constant dollars - CPI)	**2012 (constant dollars - CPI)**	**Net Growth**	**Percent growth**
Total County Value	2,655,807,379	5,845,982,803	3,190,175,424	120%
Livestock Value	78,450,042	371,777,942	293,327,899	374%

Sources: Kern County Department of Agriculture and Measurement Standards 1987, 2012; DOF 2018.
Key:
CPI = California Consumer Price Index

Significance of Potential Impacts

The data summarized above indicate that Kern County livestock productivity has substantially increased even as grazing land use significantly decreased, apparently by as much as 700,000 acres as estimated in annual County crop reports during the 25 years prior to 2012. Over approximately the same time (1988 to 2016), FMMP surveys indicate that mapped grazing land has increased by over 100,000 acres and is currently available in amounts that significantly exceed the reported annual rangeland actually in use for grazing in the County. Unlike the conversion of active farmland, which physically displaces productive agriculture on the affected land, grazing productivity data in Kern County over the last three decades indicate that grazing productivity does not decrease as the availability or use of grazing land decreases. The best available data, in fact, show that livestock value substantially increased even as grazing land use decreased in the County over the last 25 years. Furthermore, it is reasonable to expect that available grazing land will continue to increase during the next 25 years as it has in the previous 25 years. In addition, CalGEM data for 1985 through 2012 demonstrate substantial oil and gas activities in those years (see the 2015 FEIR pages 2-22 and 3-16). The net increase of over 100,000 acres of grazing land acres in Kern County as documented by the FMMP, which occurred during a period of active oil and gas development, suggests that grazing land acres can be expected to continue increasing together with continued oil and gas development over the next 25 years.

These data indicate that the productivity of Kern County grazing land would not be significantly affected by the potential impact to about 1,900 acres of grazing land per year—and a total 25-year impact to about 48,000 acres—that could occur from the implementation of the Project. A potential impact on 48,000 acres over 25 years, for example, would be approximately 7% of the total reduction in reported rangeland use in the County over the 25 years from 1987 to 2012. During this period, livestock value generated by sheep and cattle sales rose faster than for County agriculture as a whole, and by nearly 900% in nominal value and 400% in inflation-adjusted value.

In addition, there is substantial evidence that sheep and cattle grazing has occurred and will continue to occur even in highly developed Tier 1 areas. Consequently, a substantial portion of the area that could be subject to potential impacts, using the projected ground disturbance levels summarized in Table 4.4-71 of the 2015 FEIR will, in fact, be available for grazing during most of the projected 25-year analysis period. Both sheep and cattle currently graze in Tier 1 locations in close proximity with oil and gas operating equipment. Sheep can be managed to graze on forage immediately adjacent to oil and gas equipment, and in some locations cattle range freely throughout operating oilfields (see Appendix G of the 2018 SEIR [SREIR Volume 8]). A major ranching operator with land near some of the largest oil and gas well fields in the Western Subarea has stated that oil and gas development helps preserve grazing lands and allows for the return of forage on newly completed well sites within three years from well completion (see Appendix D of the 2018 SEIR [SREIR Volume 8]). There is also substantial evidence that heavily developed oil and gas locations have been decommissioned and returned to grazing uses in the Project Area over time. There is no evidence that any livestock operations have been physically harmed by oil and gas operations or adversely affected by split-estate landholdings in Kern County.

In summary, the estimates of impacts to grazing land using the projected ground disturbance levels in discussed in Appendix F of the 2015 FEIR, (SREIR Volume 4) provide an extremely conservative projection of potential future Project impacts. Heavily developed Tier 1 areas are currently, and will in the future continue to be, used for grazing and net impacts will likely be significantly lower than projected using the ground disturbance factors.

In addition, the maximum potential grazing land impacts are much smaller than the changes exhibited by long-term trends in grazing activity. Over the last 25 years, the reported livestock use of County rangeland has apparently decreased by several hundred thousand acres, even as the supply of available rangeland has increased. The number of cattle in the County inventoried at the start of 2012 was significantly greater than in 1987, and the County's share of total state cattle and sheep has increased. The value of livestock, almost all generated by cattle and sheep, substantially increased in nominal and inflation-adjusted terms, and more rapidly than the County's value of agriculture as a whole. Based on these considerations, the potential loss of grazing acreage due to Project implementation would not be expected to significantly affect the productivity of grazing activity in the County.

While Project implementation is not expected to cause a significant impact on grazing in the County, the implementation of MM 4.4-16 in the MMRP, which was adopted to mitigate Project impacts to biological resources, also will benefit grazing lands. MM 4.4-16 requires, for the first time in Kern County history, that all ground disturbance associated with oil and gas activities subject to the amended and revised Ordinance be mitigated. This new mandatory mitigation requirement generally requires mitigation at a 1.0 to 1.0 ratio (1 acre of new disturbance requires 1 acre of mitigation). Only in locations where existing oil and gas activity has already disturbed, more than 70% of the land in a proposed site plan is the minimum mandatory mitigation reduced, and even in those areas mitigation at a 1.0 to 0.5 ratio (1 acre of new disturbance requires 1/2 acre of mitigation) is required. The MMRP considers that other forms of mitigation, such as through agreements with state or federal wildlife agencies, or by means of regional habitat conservation plans or similar programs, will fulfill a significant portion of the required mitigation. However, all new ground disturbance for future oil and gas activities subject to the Ordinance must, at a minimum, meet the mandatory land disturbance mitigation standards set forth in the MMRP. As discussed above, non-native annual grasslands predominate in the rangeland/grazing land portions of the Project Area, and their growth creates fire risks and adverse impacts to native plants and species. Grazing has been recognized as a valuable means for controlling non-native annual grasslands in the Project Area.

Lands currently mitigated under MM 4.4-16 include habitat defined as “rangeland” in California Public Resources Code Section 4789.2(i): “natural grasslands, savannas, shrublands (including chaparral), deserts, wetlands, and woodlands (including Eastside ponderosa pine, pinyon, juniper, and oak) which support a vegetative cover of native grasses, grasslike plants, forbs, shrubs, or naturalized species.” Thus, it is reasonable to assume that certain of the mitigation lands used to meet MMRP or other qualifying land disturbance mitigation obligations will permit livestock grazing in some form. Taking the effects of MM 4.4-16 into account, together with the increased availability and decreased use of rangeland/grazing land discussed that have occurred since 1987, total grazing land acres can be expected to continue increase together with continued oil and gas development over the next 25 years.

Thus, even if the most conservative projections of impacts did occur, the required mandatory ground disturbance mitigation requirements in the amended and revised Ordinance would be expected to substantially offset the relatively small amount of grazing land potentially impacted by the Project.

The impact to gazing land is less than significant.

Mitigation Measures

No mitigation measures are required.

Level of Significance

Less than significant

4.2.4 Cumulative Setting, Impacts, and Mitigation Measures

Cumulative Setting

The geographic scope for cumulative impacts to agricultural and forest resources encompasses the whole of Kern County. As agricultural land statistics and characteristics are typically collected at the County level, cumulative impacts to agricultural and forest land should be evaluated within the context of Kern County.

Impacts that were evaluated to have no impact are not discussed in the cumulative analysis.

Impact 4.2-8: Cumulative Impacts to Agricultural or Forest Resources

The plans evaluated in this cumulative analysis are described in the 2015 FEIR, Section 3.8, Cumulative Projects. Implementation of these plans and any projects associated with these plans would be required to comply with the goals, policies, and implementation measures of applicable federal and local laws and land use standards imposed by the respective jurisdictions within which each related project is located.

With respect to agricultural farmland conversion, from 1998 to 2013, in Kern County, the average annual agricultural lands conversion rate has been 1,085 acres.

Under the worst-case scenario, 298 acres of Prime Farmland, Farmland of Statewide Importance, or Unique Farmland could be converted annually from the implementation of the proposed Project. This 298 acres of converted Farmland would combine with other losses throughout the County to result in a significant cumulative impact on agriculture.

Population growth is expected to continue in the County, and conversion of agricultural land to non-agricultural use can also be expected to occur from the need for additional residential development and infrastructure to accommodate the growth in the County.

The 2014 Kern COG Regional Transportation Plan (RTP)/Sustainable Communities Strategy (SCS) forecasts the addition of 577,100 people and the conversion of 24 square miles, less than 2% of Farmland and 1/10th the conversion compared to the previous 22 years (Kern COG 2014). Implementation of the Kern COG RTP/SCS would result in a reduction in the rate of Farmland conversion due to policies to concentrate new development in existing urban areas and potential impacts would be mitigated. Nonetheless, due to the importance of the region's agricultural resources, the impacts related to the Project's incremental contribution to the cumulative farmland conversion would be considered cumulatively considerable.

Because there are other factors, such as commodity pricing in the global market and water pricing and availability, that influence the feasibility of ongoing agricultural operations in Kern County, there may be a cumulative significant loss in agricultural resources in Kern County for reasons that are outside the jurisdiction and control of the County. The Kern County General Plan also forecast a net loss of 80,854 acres of Prime and Important Farmland and 55,000 acres of grazing lands in Kern County based on land use conversions consistent on existing land use plans, which would further reduce Kern County's agricultural lands.

Mitigation Measures

Implement MM 4.2-1, as described above.

Level of Significance After Mitigation

Project impacts would be significant and unavoidable.

Impact 4.2-9: Cumulative Impacts to Rangeland/Grazing Land

The environmental impact report for the Kern County General Plan, which was adopted in 2004, estimated that General Plan implementation could result in the conversion of approximately 55,000 acres of grazing land. Kern County 2004. The Kern County General Plan used a conservative estimate for the potential conversion of grazing land by using the Map Code 4.3 (Specific Plan Required) General Plan land use designations, which have an adopted sheet for each named area (Specific Plan Required Maximum Allowed Land Uses) that contains an allocation for all map code uses and a not-to-exceed total of recommended residential units. These areas have an interim designation of primarily Resource Management and are zoned A (Exclusive Agriculture) and A -1 (Limited Agriculture), both of which permit grazing. The Map Code 4.3 lands totaled approximately 64,129 acres. The 2004 General Plan FEIR calculated the number of Map Code 4.3 areas that occur in the mountain and desert areas where the lands are used for grazing and not cultivated crops and determined that 55,000 acres of grazing land could be converted if the Map Code 4.3 areas were developed based on their adopted allocation for all map code uses and the applicable not-to-exceed total of recommended residential units (Kern County 2004). Since that time, 12,692 acres of Map Code 4.3 areas have been rescinded and included in the Greater Tehachapi Specific Plan and the Tejon Mountain Village Specific Plan. Based on the new land uses in both of these plans, 3,048 acres were removed from grazing uses in the plan areas formerly subject to the Map Code 4.3 designation.

Consequently, using the maximum potential impact related to oil and gas activity over 25 years, as shown in Table 4.2-~~*19*~~*20*, plus the maximum potential General Plan impact to grazing land of 55,000 acres (see Kern County 2004), the maximum potential cumulative impacts to grazing land would be approximately 103,891 acres (55,000 acres from General Plan implementation plus 48,891 acres from Project implementation). Since 2004, however, the level of potential grazing land impacts from General Plan implementation projected in 2004 has not occurred, and only 3,048 acres have been redesignated from resource zoning and have had grazing removed in former Map Code Section 4.3 areas. Accounting for the actual impacts since 2004, the maximum potential grazing land conversion from General Plan implementation in remaining Map Code 4.3 designations is at most 51,952 acres (55,000 acres minus the 3,048 acres that were redesignated from resource zoning and have had grazing removed since 2004). Based on the total amount of grazing land impacts from General Plan implementation since 2004 (3,048 acres), and the lack of infrastructure for developing the remaining areas subject to the General Plan Map Code 4.3 (Specific Plan Required) designation, substantial evidence indicates that much less than 51,952 acres will actually be impacted by General Plan implementation over the next 20 years. If future grazing land impacts are comparable to the level of impacts that occurred since 2004, General Plan implementation over the next 20 years could potentially impact approximately 3,904 acres. This would result in a total grazing land impact from General Plan implementation of just 6,952 acres. Hence, the potential cumulative grazing land impacts attributable to the implementation of the current County General Plan and the Project would be about 55,843 acres accounting for the actual rate of grazing land conversion due to General Plan implementation since 2004.

As discussed above, impacts attributable to oil and gas development using the ground disturbance factors are extremely conservative as even reasonably intensive oil and gas operations allow for livestock grazing. In addition, General Plan impacts since 2004 have been significantly lower than projected, and substantial evidence indicates that the total of these impacts would much lower than the 55,000 acres considered in 2004. Kern County 2004. Consequently, the maximum potential cumulative impacts to grazing land, 103,891 acres, includes highly conservative estimates of both actual Project impacts and actual and reasonably foreseeable General Plan implementation impacts. The potential cumulative impacts to grazing land are larger than for the Project alone, but long-term trends in grazing activity (e.g., increasing total rangeland acreage in County, decreasing use of rangeland acres in County, and higher livestock productivity despite fewer acres in use) exhibit much larger changes over time. The potential maximum cumulative grazing land impact, for example, is lower than the total amount of new grazing land that has been added in the County since 1988, according to the FMMP. The maximum cumulative impact acreage is also many times less than the reported reduction in rangeland use from 1987 to 2012. Notwithstanding the reduction in rangeland used since 1987, grazing productivity has significantly increased in Kern County over time, and at a rate faster than for the County's agricultural economy as a whole. Based on these considerations, the level of potential cumulative impacts to rangeland that could occur from Project and General Plan implementation would be unlikely to significantly reduce the productivity of grazing activity in the County.

Mitigation Measures

No mitigation measures are required.

Level of Significance after Mitigation

Impacts would be less than significant.

Figure 4.2-1: Number of Beef Cows, Milk Cows and Other Cattle in Kern County, 1987 and 2012

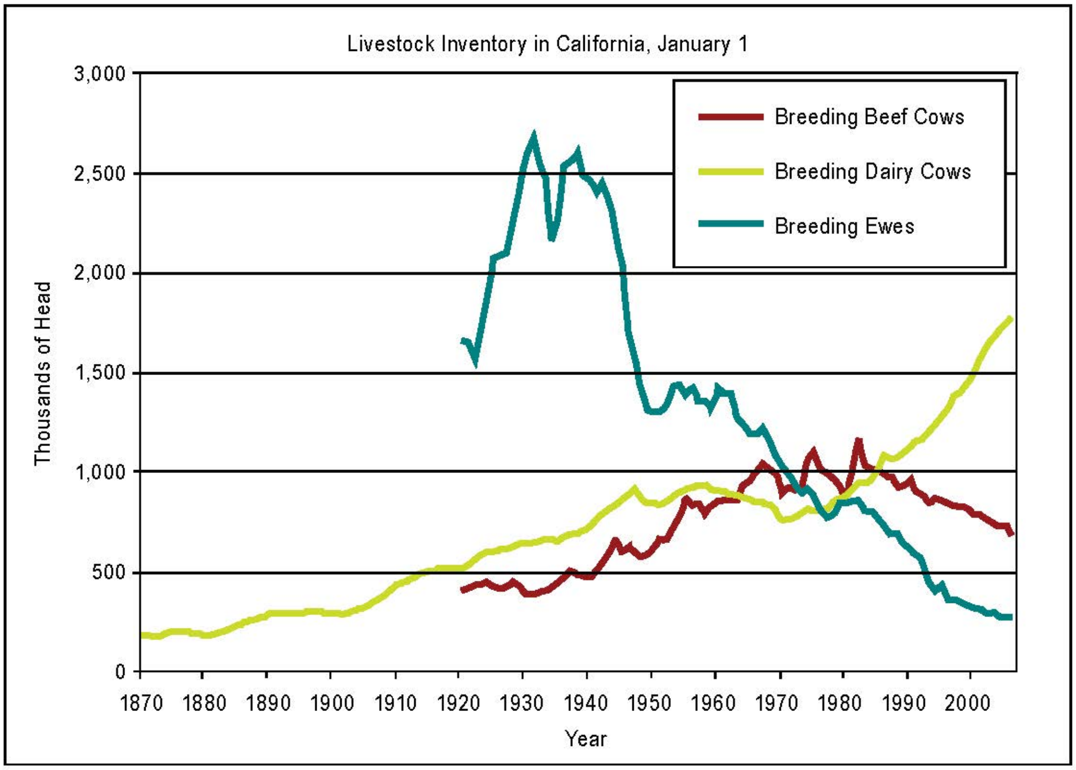

Figure 4.2-2: Inventory of Breeding Cows, Dairy Cows and Ewes in California January 1 of Each Year

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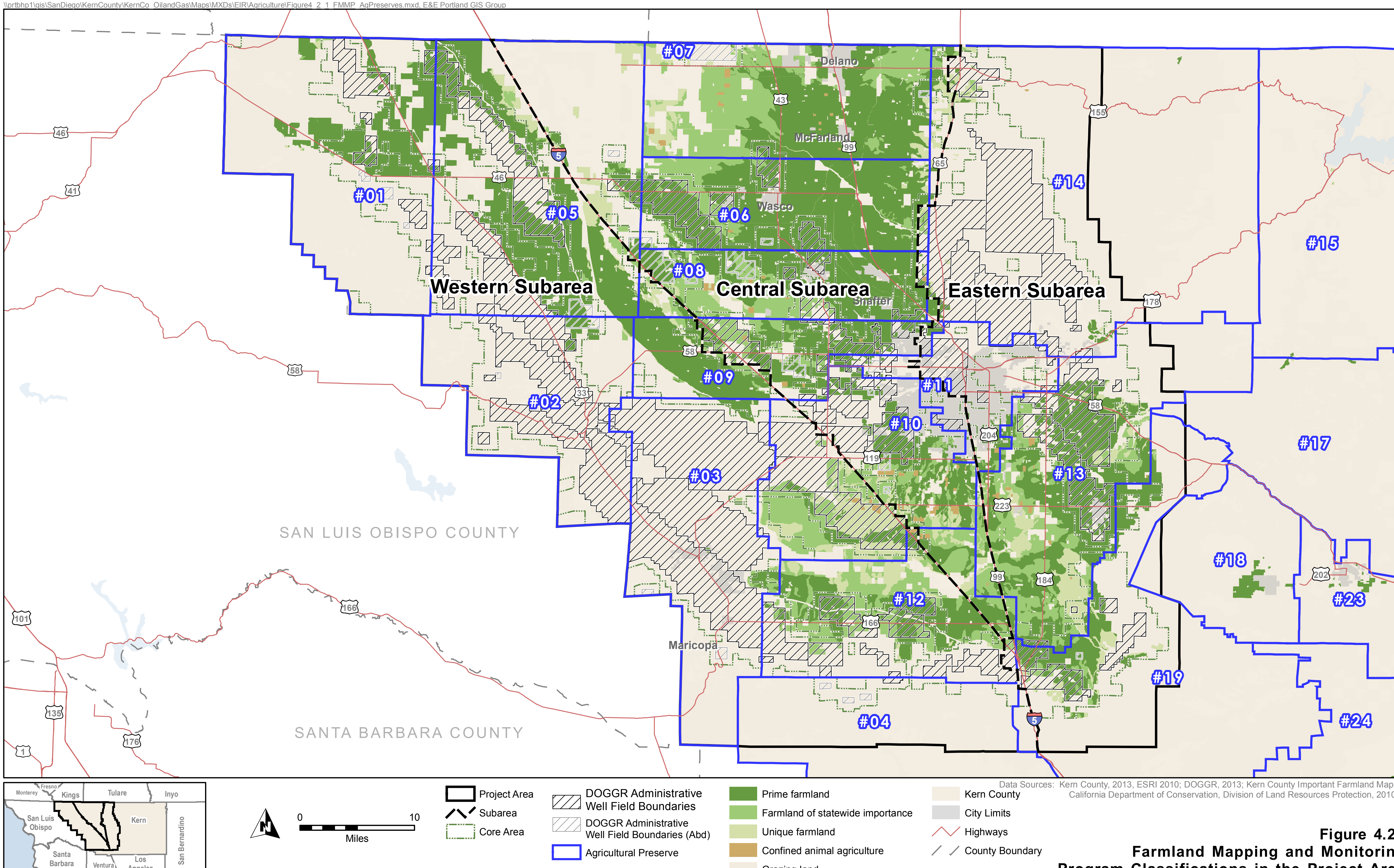

Figure 4.2-3
Farmland Mapping and Monitoring Program Classifications in the Project Area

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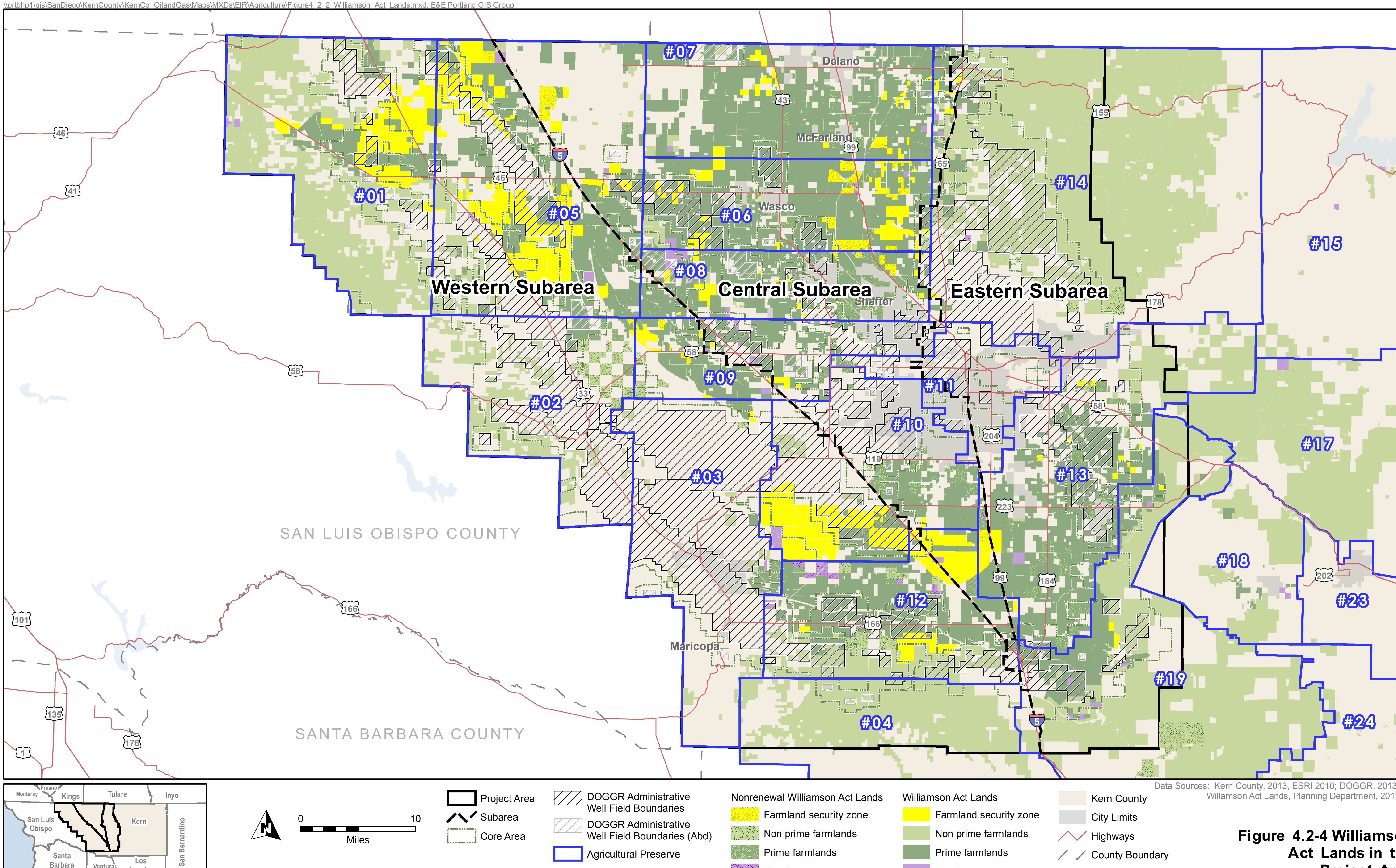

Figure 4.2-4 Williamson Act Lands in the Project Area

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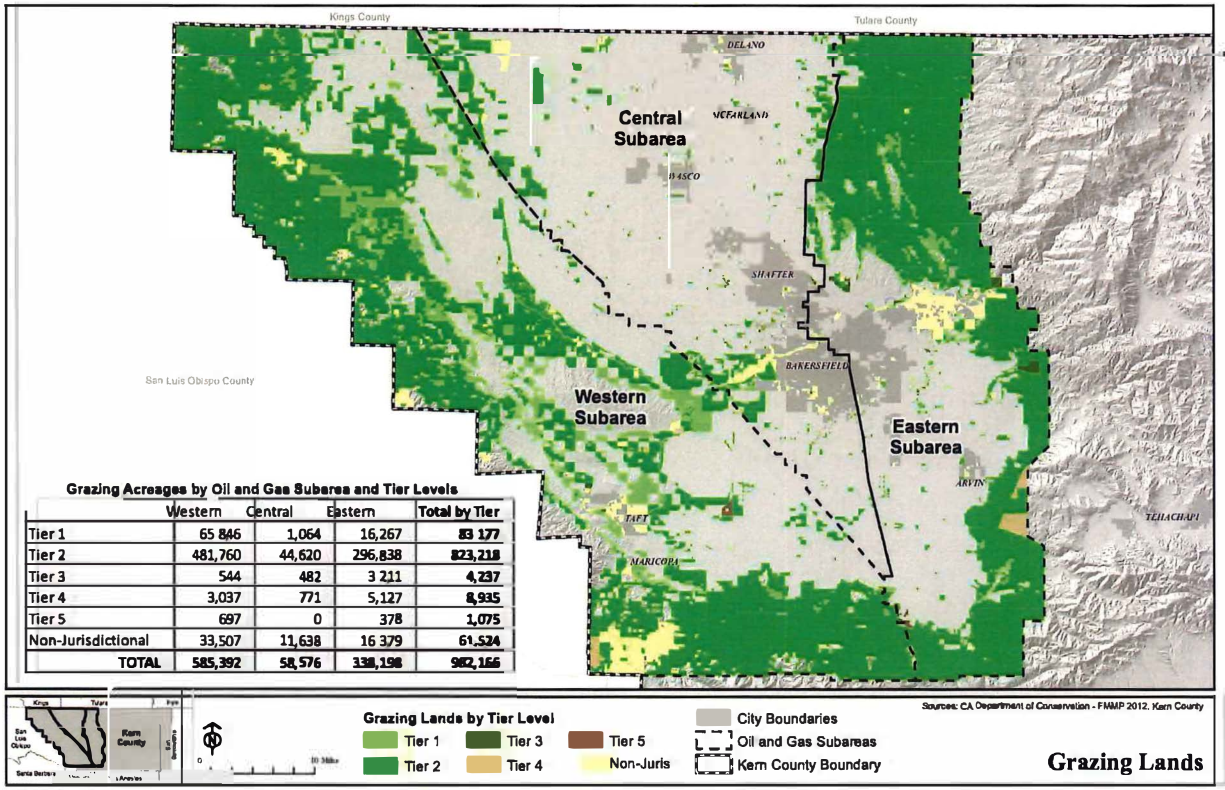
Figure 4.2-5
Location of Grazing Land in Project Area by Tier and Subarea



Grazing Acreages by Oil and Gas Subarea and Tier Levels

	Western	Central	Eastern	Total by Tier
Tier 1	65 846	1,064	16,267	83 177
Tier 2	481,760	44,620	296,838	823,218
Tier 3	544	482	3 211	4,237
Tier 4	3,037	771	5,127	8,935
Tier 5	697	0	378	1,075
Non-Jurisdictional	33,507	11,638	16 379	61,524
TOTAL	585,392	58,576	338,198	982,166

Figure 4.2-6: Proportion of Tier 1 Acreage in Project Area by Subarea

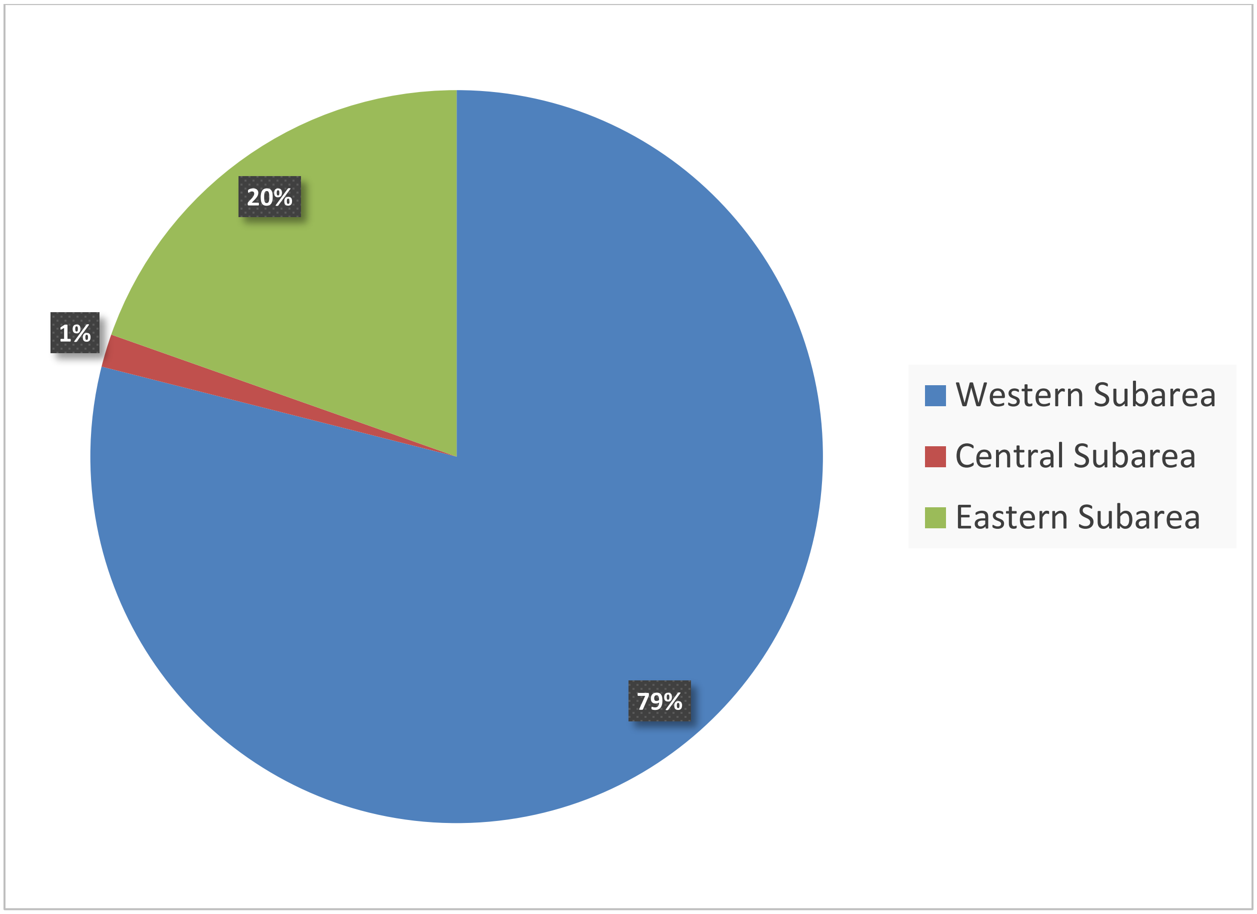
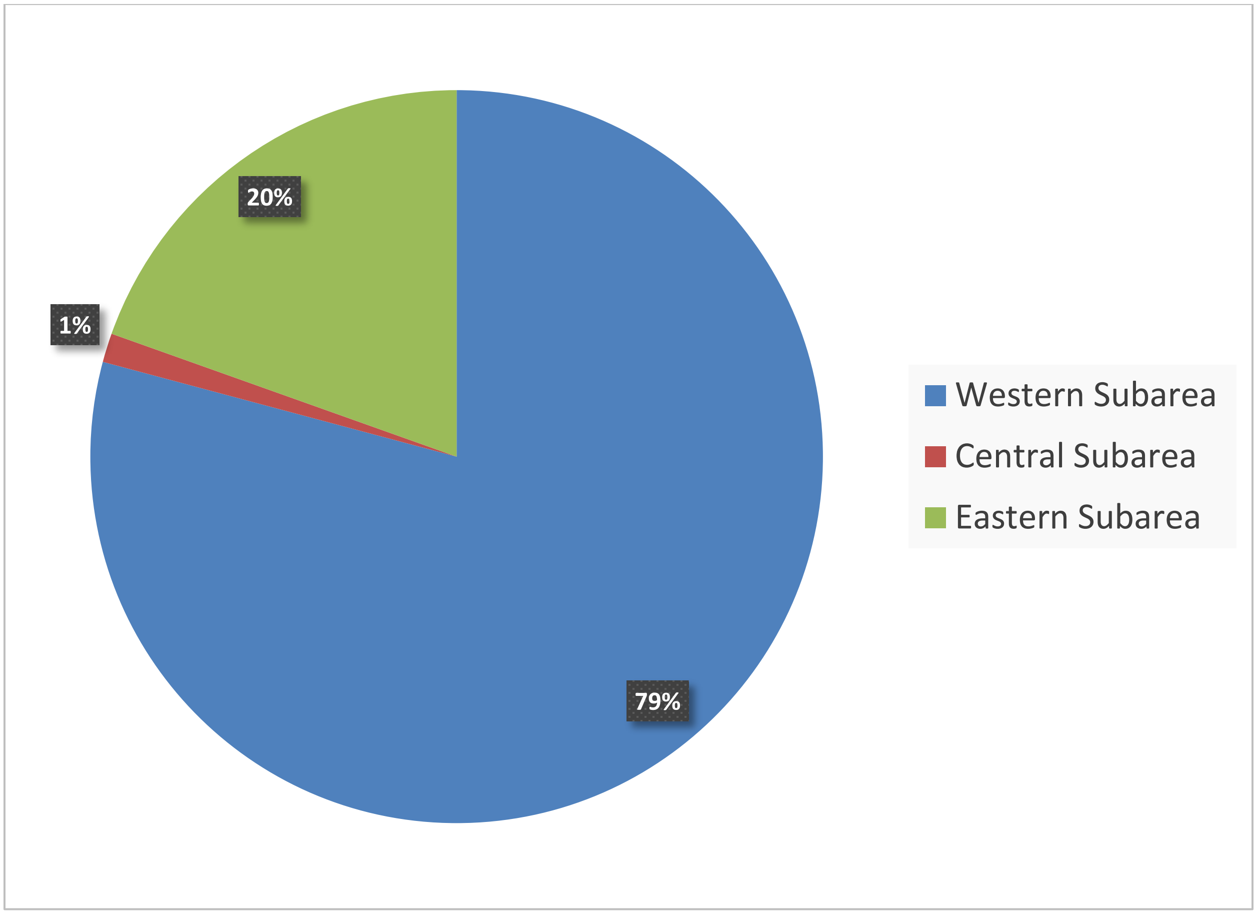


Figure 4.2-7: Proportion of Grazing Land Acreage in Tier 1 Portions of Project Area and Subarea



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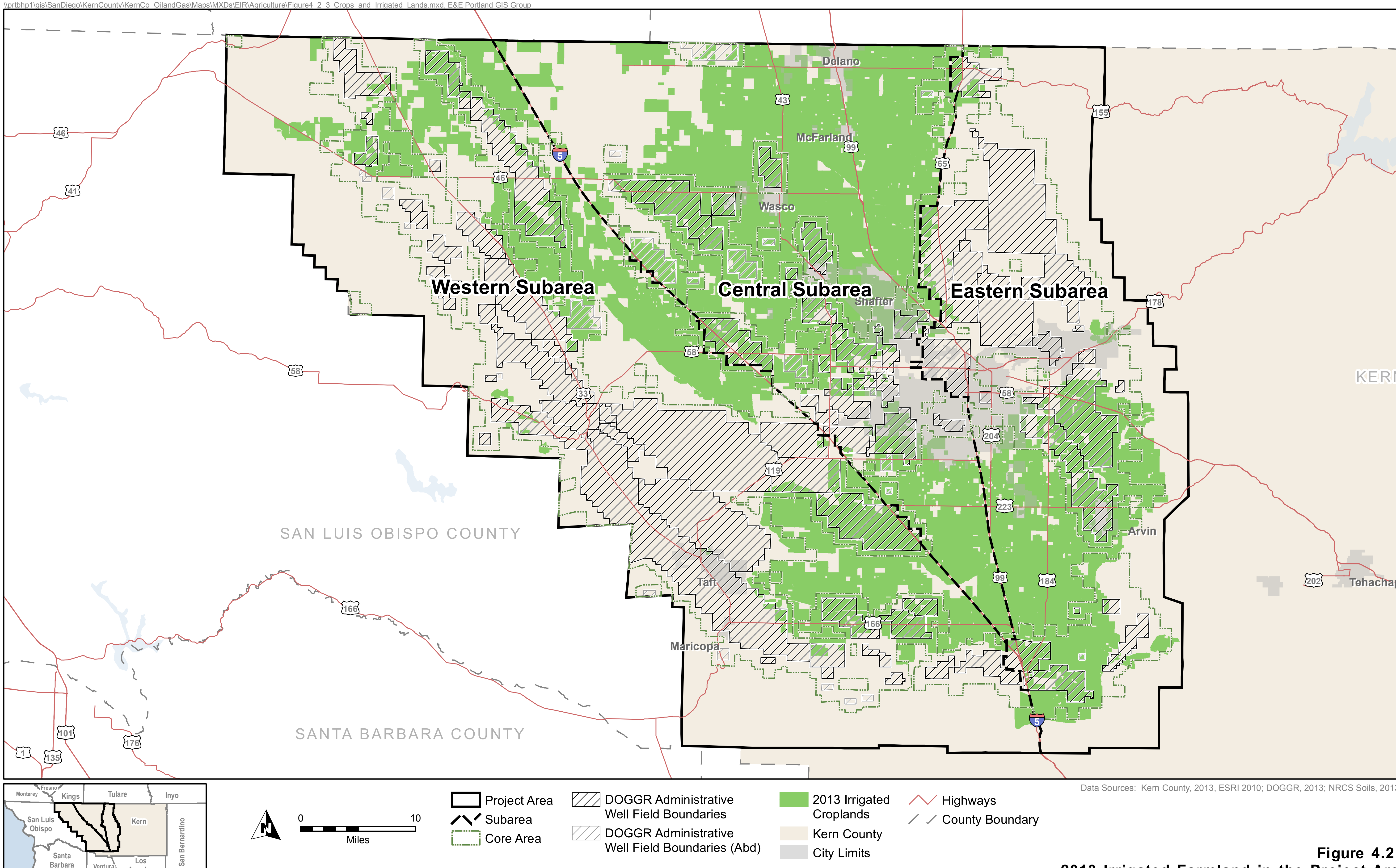


Figure 4.2-8
2013 Irrigated Farmland in the Project Area

Figure 4.2-9: **Acreage of Pasture/Rangeland Reported in Use Annual Kern County Crop Reports 1981-2016**

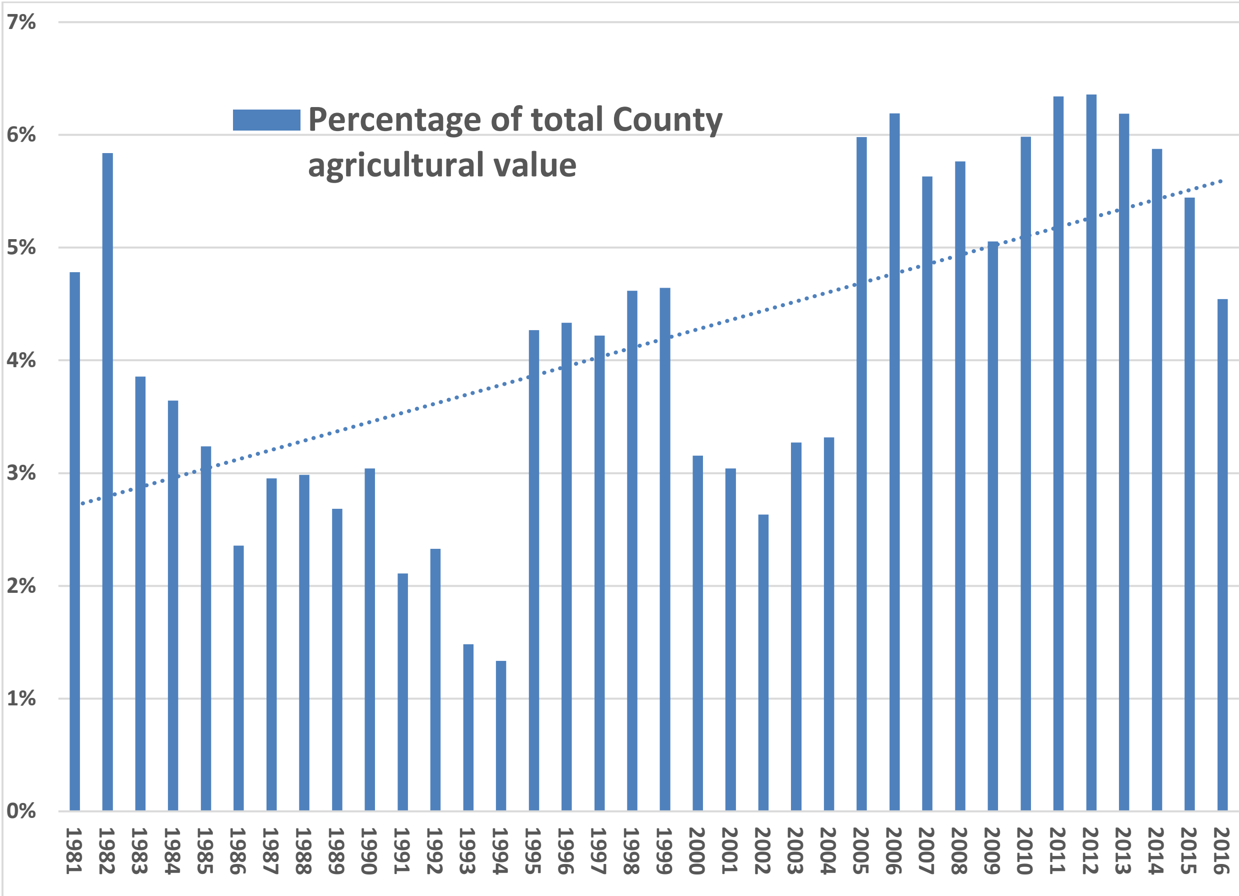


Figure 4.2-10: Livestock Value Per Year, Nominal Dollars and 2009 Inflation-Adjusted Dollars (CPI) 1981-2016

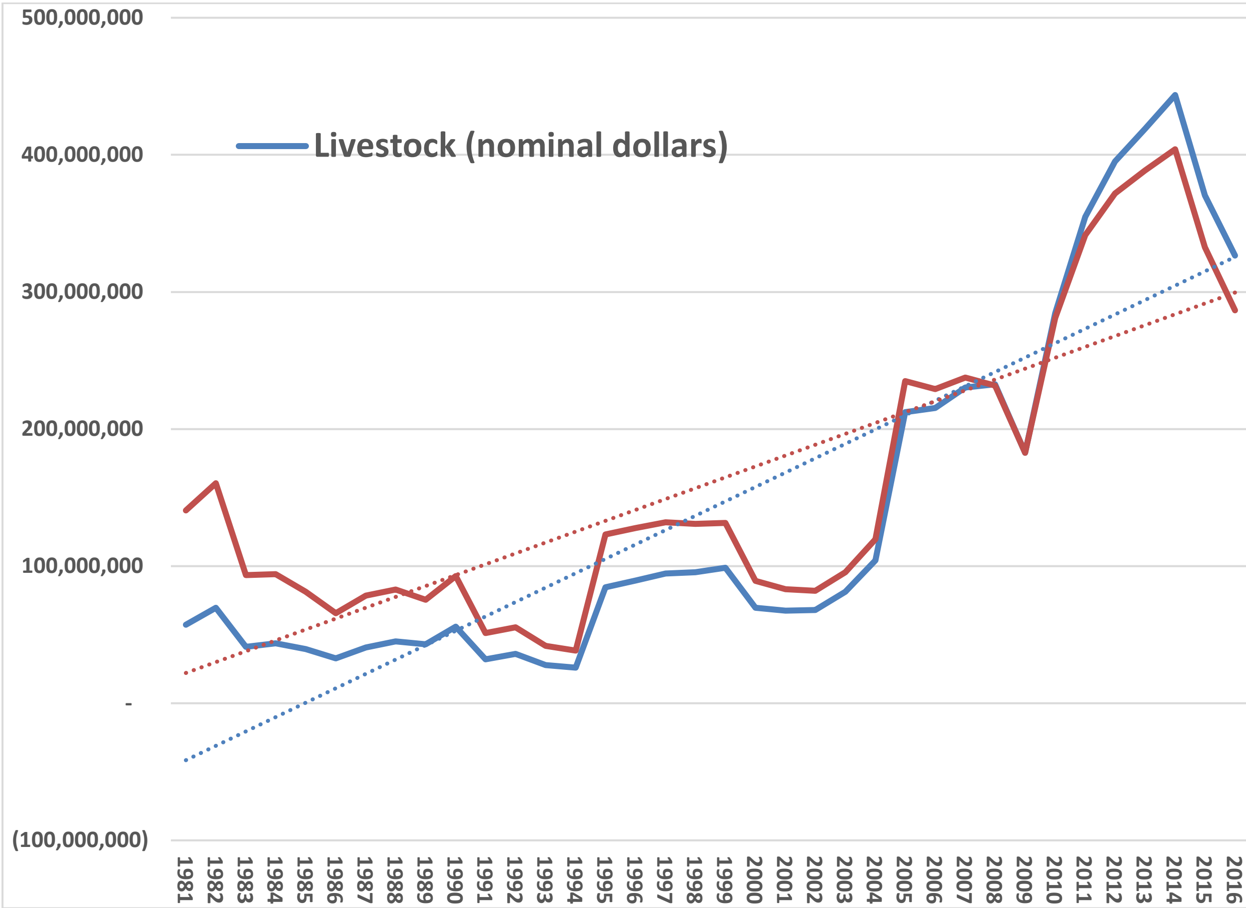
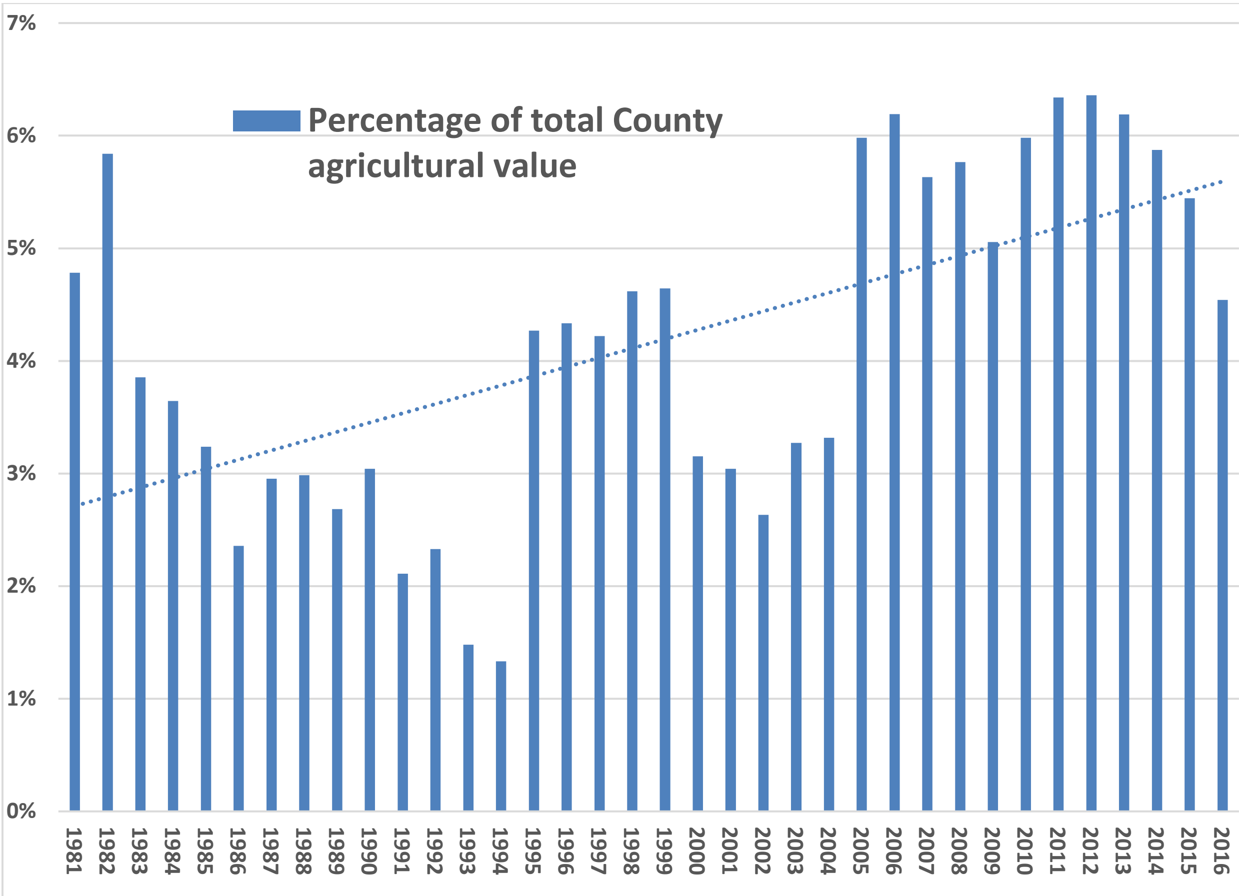


Figure 4.2-11: Livestock Value as Percentage of Total County Agricultural Value 1981-2016



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Section 4.3
Air Quality

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Section 4.3
Air Quality

4.3.1 Introduction: Purpose/Scope

This section of the Supplemental Recirculated Environmental Impact Report (SREIR) describes the affected environment and regulatory setting for air quality in relation to the attainment status of the San Joaquin Valley Air Basin (SJVAB) in terms of particulate matter less than 2.5 microns ($PM_{2.5}$) attainment and $PM_{2.5}$ attainment plans *and provides information on the potential adverse health effects of $PM_{2.5}$ emissions*; clarifies the enforceability and impact of Mitigation Measure (MM) 4.3-8 on $PM_{2.5}$ emissions; recirculates and discusses the multi-well Health Risk Assessment (HRA) as Appendix B (Multi-Well HRA) and includes discussion of COVID-19. This section also describes the impacts to air quality for the relevant topics, that would result from implementation of the Amendment to Chapter 19.98 (Oil and Gas Production) and related ordinance amendments to the Kern County Zoning Ordinance, and future development of oil and gas resources pursuant to the Amended Ordinance (Project), and mitigation measures that would reduce these impacts, if necessary. *Except where specifically noted, all underlined and italicized text indicates additions, and italicized strikethrough text indicates deletions from the SREIR (August 2020). Nonitalicized underlined and strikethrough text is the same as in the SREIR (August 2020).*

4.3.2 Environmental Setting

The Project Area encompasses 3,700 square miles and generally includes most of the San Joaquin Valley (SJV) Floor or western portion of Kern County. The SJV Floor is within the southern end of the SJVAB, which is made up of all or portions of eight counties in California's Central Valley. These counties include Fresno, Kings, Madera, Merced, San Joaquin, Stanislaus, and Tulare counties, as well as the SJV portion of Kern County. The western portion of Kern County, where the Project is located is regulated by the San Joaquin Air Pollution Control District (SJVAPCD).

Air pollution in the SJVAB can be attributed to both human-related (anthropogenic) and natural (non-anthropogenic) activities that produce emissions. Air pollution from significant anthropogenic activities in the SJVAB includes a variety of industrial-based sources as well as on- and off-road mobile sources. Activities that tend to increase mobile activity include increases in population, increases in traffic (including automobiles, trucks, aircraft, and rail), urban sprawl (which increases commuter driving distances), and general local land management practices as they pertain to modes of commuter transportation (SJVAPCD 2015). Air pollution is also transported into the SJVAB from a variety of sources, including northern California and Asia (Faloona et al. 2015).

Meteorological Conditions

The SJVAB is the southern half of California's Central Valley and is 250 miles long and bordered by mountains on three sides. The SJV is bordered by the Sierra Nevada Mountains to the east (8,000 to 14,491 feet in elevation), the Coast Ranges to the west (averaging 3,000 feet in elevation), and the Tehachapi mountains to the south (6,000 to 7,981 feet in elevation). There is a slight downward elevation gradient from Bakersfield in the southeast end (elevation 408 feet) to sea level at the northwest end where the valley opens to the San Francisco Bay at the Carquinez Straits. At its northern end is the Sacramento Valley, which comprises the northern half of California's Central Valley. The bowl-shaped topography inhibits movement of pollutants out of the valley.

The overall climate in the SJVAB is warm and semi-arid. The SJV is in a Mediterranean Climate Zone. Mediterranean Climate Zones occur on the west coast of continents at 30 to 40 degrees latitude and are influenced by a subtropical high-pressure area most of the year. Mediterranean climates are characterized by sparse rainfall, which occurs mainly in the winter. There is only one wet season during the year and 90% of the precipitation falls during October through April. Snow in the SJV is infrequent and thunderstorms seldom occur. Summers are hot and dry. Summertime maximum temperatures often exceed 100 degrees Fahrenheit (°F) in the SJV.

The subtropical high-pressure area is strongest during spring, summer, and fall and produces subsiding air, which can result in temperature inversions in the valley. Air temperature in the lowest layer of the atmosphere typically decreases with altitude. A reversal of this atmospheric state, where the air temperature increases with height, is termed an inversion. The height of the base of the inversion is known as the "mixing height." This is the level to which pollutants can mix vertically. Mixing of air is minimized above the inversion base. The inversion base represents an abrupt density change where little air movement occurs. A temperature inversion can act like a lid, inhibiting vertical mixing of the air mass near the land surface, resulting in trapping of air pollutants below the inversion. Most of the surrounding mountains are above the normal height of summer inversions (1,500 to 3,000 feet). Concentration levels of air pollutants are directly related to inversion layers due to the limitation of vertical mixing. Inversion layers enhance the formation of ozone (O_3) and limit dispersion of directly emitted pollutants like particulate matter (PM) and carbon monoxide (CO; SJVAPCD 2015).

Winter-time high pressure events can often last many weeks with surface temperature often lowering into the 30°F range. During these events, fog can be present and inversions are extremely strong. These winter-time inversions can inhibit vertical mixing of pollutants to a few hundred feet (SJVAPCD 2015)

The transport and dispersion of air pollutants in ambient air are influenced by many complex factors. The primary factors are wind, topological boundaries, and atmospheric stability. During the summer, wind speed and direction data indicate that summer wind usually originates at the north end of the SJV and flows in a south-southeasterly direction through the valley and the Tehachapi Pass, into the Mojave Desert. During the winter months, the SJV experiences light, variable winds, less than 10 miles per hour.

Topography

Air pollution is directly related to a region's topographic features. The SJVAB is approximately 250 miles long, an average of 35 miles wide, and is the second largest air basin in the state. The SJVAB is defined by the Sierra Nevada Mountains in the east (8,000 to 14,000 feet in elevation), the Coast Ranges in the west (averaging 3,000 feet in elevation), and the Tehachapi Mountains in the south (6,000 to 8,000 feet in elevation). The valley is basically flat with a slight downward gradient to the northwest, and opens to the sea at the Carquinez Straits where the San Joaquin-Sacramento Delta empties into San Francisco Bay.

Wind Patterns

The SJVAB's topography has a dominating effect on wind patterns. Winds tend to blow somewhat parallel to the valley and mountain range orientation. In spring and early summer, thermal low-pressure systems develop over the interior basins east of the Sierra Nevada mountain range, and the Pacific High (high pressure system that develops over the central Pacific Ocean near the Hawaiian Islands) moves northward. These developments and the topography produce the high incidence of relatively strong northwesterly winds in the spring and early summer (SJVAPCD 2013a).

Wind speed and direction data indicate that during the summer, winds usually originate at the north end of the SJVAB and flow in a south-southeasterly direction through the Tehachapi Pass into the Southeast Desert Air Basin. Wind speed and direction data indicate that during the winter, winds occasionally originate from the south end of the SJVAB and flow in a north-northwesterly direction. Also, during winter, the SJVAB experiences light, variable winds, typically less than 10 mph. Low wind speeds, combined with low inversion layers in the winter, create a climate conducive to high CO and inhalable particulates concentrations (SJVAPCD 2013a).

For the southernmost portion of the SJVAB, steady winds are typical in the mountainous area that characterizes this portion, and quickly disperse air pollutants.

Temperature

The vertical rise and mixing of air pollutants is limited by the presence of persistent temperature inversions. Inversions may be either ground level or elevated. Ground-level inversions occur frequently during early fall and winter (i.e., October through January). High concentrations of primary pollutants, which are those emitted directly into the atmosphere (e.g., CO), may be found at these times. Elevated inversions act as a lid over the basin and limit vertical mixing, resulting in severe air stagnation. Elevated inversions contribute to the occurrence of high levels of O_3 during the summer months.

In winter, storm systems moving in from the Pacific Ocean bring a maritime influence to the SJV. The Sierra Nevada mountain range prevents the cold, continental air masses from influencing the valley. Temperatures below freezing are unusual. In the southern portion of the SJVAB, average high temperatures in the winter are in the 60s, but highs in the 30s and 40s can occur with persistent fog and low cloudiness. In summer, high temperatures often exceed 100 degrees, with averages in the mid/high 90s in the southern SJVAB. Summer low temperatures average in the mid-50s in the southern basin (Western Regional Climate Center 2014).

Precipitation

Precipitation in the SJVAB is strongly influenced by the position of the semi-permanent subtropical high-pressure area located off the Pacific Coast (the Pacific High). In the winter, this high-pressure system moves southward, allowing Pacific storms to move through the SJVAB. The majority of the precipitation in the valley is winter rain produced by these storms. Snowstorms, hailstorms, and ice storms occur infrequently in the valley, and severe occurrences are very rare.

Precipitation on the SJVAB floor and in the Sierra Nevada decreases from north to south. This decrease is primarily because the Pacific storm track often passes through the northern part of the state while the southern part of the state remains protected by the Pacific High. For example, the northern portion of the SJVAB (Manteca and Stockton areas) receives approximately 20 inches of rain per year; the central portion of the basin (Fresno area) receives approximately 10 inches of rain per year; and the southern portion of the basin (Bakersfield area) receives less than 6 inches of rain per year. The Tejon Pass area receives about 12 inches of rain per year (SJVAPCD 2013a).

Existing Air Quality

The U.S. Environmental Protection Agency (EPA) and the California Air Resources Board (CARB) have established health-based ambient air quality standards for several different pollutants. The EPA sets National Ambient Air Quality Standards (NAAQS) for the following seven pollutants for ozone, CO, nitrogen dioxide (NO_2), respirable particulate matter (PM_{10}), fine particulate matter ($PM_{2.5}$), sulfur dioxide (SO_2) and lead (Pb). These seven pollutants are commonly referred to as "criteria pollutants." Primary standards provide public health protection, including protecting the health of "sensitive" populations, such as asthmatics, children, and the elderly. Secondary standards provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings.

In addition, CARB has established California Ambient Air Quality Standards (CAAQS) standards for these pollutants, as well as for sulfate (SO_4^{2-}), visibility reducing particles, hydrogen sulfide (H_2S), and vinyl chloride. California standards are generally stricter than national standards. The NAAQS and the CAAQS are shown in Table 4.3-1.

Table 4.3-1: National and California Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards[b, e]	National Standards[a, e]	
			Primary[c]	Secondary[d]
Ozone (O_3)	1-Hour	0.09 ppm (180 µg/m^3)	---[f]	---
	8-Hour	0.070 ppm (137 µg/m^3)	0.070 ppm (147 µg/m^3)	Same as Primary Standard
Carbon monoxide (CO)	1-Hour	20 ppm (23 mg/m^3)	35 ppm (40 mg/m^3)	---
	8-Hour	9.0 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)	---

Table 4.3-1: National and California Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards[b, e]	National Standards[a, e]	
			Primary[c]	Secondary[d]
Nitrogen dioxide (NO_2)	1-Hour	0.18 ppm (339 µg/m^3)	100 ppb (188 µg/m^3)	---
	Annual Mean	0.030 ppm (57 µg/m^3)	0.053 ppm (100 µg/m^3)	Same as Primary Standard
Sulfur dioxide (SO_2)[g]	1-Hour	0.25 ppm (655 µg/m^3)	75 ppb (196 µg/m^3)	---
	3-Hour	---	---	0.5 ppm (1,300 µg/m^3)
	24-Hour	0.04 ppm (105 µg/m^3)	---	---
Respirable Particulate Matter (PM_{10})[h]	24-Hour	50 µg/m^3	150 µg/m^3	Same as Primary Standard
	Annual Mean	20 µg/m^3	---	---
Fine Particulate Matter ($PM_{2.5}$)[h]	24-Hour	---	35 µg/m^3	Same as Primary Standard
	Annual Mean	12 µg/m^3	12.0 µg/m^3	15 µg/m^3
Lead (Pb)	30-day Average	1.5 µg/m^3		
	Rolling 3-month Average		0.15 µg/m^3	Same as Primary Standard
Hydrogen sulfide (H_2S)	1-Hour	0.03 ppm (42 µg/m^3)	No Federal Standards	
Sulfate (SO_4^{2-})	24-Hour	25 µg/m^3		
Visibility reducing particles	8-Hour	See Note i		
Vinyl chloride[j]	24-Hour	0.01 ppm (26 µg/m^3)		

Sources: EPA 2016a; CARB 2016.

Notes:

[a] National Ambient Air Quality Standards (other than ozone, particulate matter, and those based on annual averages or annual arithmetic mean) are not to be exceeded more than once a year. The ozone standard is attained when the fourth-highest 8-hour concentration in a year, averaged over three years, is equal to or less than the standard. For particulate matter less than 10 microns (PM_{10}), the 24-hour standard is not to be exceeded more than once per year on average over three years. The 24-hour standard is attained when the three-year average of the weighted annual mean at each monitor within an area does not exceed 150 µg/m^3. For particulate matter less than 2.5 microns ($PM_{2.5}$), the 24-hour standard is attained when 98% of the daily concentrations, averaged over three years, do not exceed 35 µg/m^3. The annual standard is attained when the three-year average of the weighted annual mean at single or multiple community-oriented monitors does not exceed 12 µg/m^3.

[b] California Ambient Air Quality Standards for ozone, carbon monoxide (except 8-hour Lake Tahoe), sulfur dioxide (SO_2; 1- and 24-hour), nitrogen dioxide (NO_2), PM_{10} and visibility reducing particles, are values that are not to be exceeded. All others are not to be equaled or exceeded.

[c] National Primary Standards: The levels of air quality necessary, with an adequate margin of safety, to protect the public health.

[d] National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse impacts of a pollutant.

Table 4.3-1: National and California Ambient Air Quality Standards

Pollutant	Averaging Time	California Standards[b, e]	National Standards[a, e]	
			Primary[c]	Secondary[d]

[e] Concentration expressed first in units in which it was promulgated. Parts per million (ppm) in this table refers to ppm by volume or micromoles of pollutant per mole of gas.
[f] The federal 1-hour ozone standard was revoked for most areas of the United States, including all of California on June 15, 2005.
[g] Final rule signed June 2, 2010. The 1971 annual and 24-hour SO_2 standards were revoked in that same rulemaking.
[h] On December 14, 2012, the national annual $PM_{2.5}$ primary standard was lowered from 15 µg/m^3 to 12 µg/m^3. Existing national 24-hour $PM_{2.5}$ standards (primary and secondary) were retained at 35 µg/m^3, as was the annual secondary standard of 15 µg/m^3. The existing 24-hour PM_{10} standards (primary and secondary) of 150 µg/m^{3}also were retained. The form of the annual primary and secondary standards is the annual mean, averaged over three years.
[i] In 1989, the California Air Resources Board converted both the general statewide 10-mile visibility standard and the Lake Tahoe 30-mile visibility standard to instrumental equivalents, which are "extinction of 0.23 per kilometer" and "extinction of 0.07 per kilometer" for the statewide and Lake Tahoe Air Basin standards, respectively.
[j] The California Air Resources Board has identified lead and vinyl chloride as "toxic air contaminants" with no threshold level of exposure for adverse health impacts determined. These actions allow for the implementation of control measures at levels below the ambient concentrations specified for these pollutants.

Key:
ppb = parts per billion
ppm = parts per million
µg/m^3 = micrograms per cubic meter
mg/m^3 = milligrams per cubic meter

Table 4.3-2 summarizes the federal and state attainment status for the SJVAB, as of 2020, based on the NAAQS and CAAQS, respectively.

Table 4.3-2: Attainment Status for the San Joaquin Valley Air Pollution Control District

Pollutant	Designation/Classification	
	Federal	State
Ozone	Nonattainment/Extreme[a,b]	Nonattainment/Severe
PM_{10}	Attainment[c]	Nonattainment
$PM_{2.5}$	Nonattainment[d]	Nonattainment
Carbon monoxide (CO)	Unclassifiable/Attainment	Attainment/Unclassified
Nitrogen dioxide (NO_2)	Unclassifiable/Attainment	Attainment
Sulfur dioxide (SO_2)	Attainment/Unclassified	Attainment
Lead (Pb)	Unclassifiable/Attainment	Attainment
Hydrogen sulfide (H_2S)	No Federal Standard	Unclassified
Sulfates (SO_4^{2-})	No Federal Standard	Attainment

Table 4.3-2: Attainment Status for the San Joaquin Valley Air Pollution Control District

Pollutant	Designation/Classification	
	Federal	State
Visibility reducing particulate	No Federal Standard	Unclassified
Vinyl chloride	No Federal Standard	Attainment

Source: SJVAPCD 2020a.
Notes:
(a) Even though the U.S. Environmental Protection Agency (EPA), revoked the federal 1-hour ozone standard, including associated designations and classifications in 2005, the EPA had previously classified the San Joaquin Valley Air Basin (SJVAB) as extreme nonattainment for this standard. The EPA approved the 2004 Extreme Ozone Attainment Demonstration Plan on March 8, 2010. Many applicable requirements for extreme 1-hour ozone nonattainment areas continue to apply to the SJVAB.
(b) Though the San Joaquin Valley (SJV) was initially classified as serious nonattainment for the 1997 8-hour ozone standard, the EPA approved reclassification to extreme nonattainment in the Federal Register on May 5, 2010.
(c) On September 25, 2008, the EPA redesignated the SJV to attainment for the PM_{10} standard and approved the PM_{10} Maintenance Plan.
(d) The SJV is designated nonattainment for the 1997 $PM_{2.5}$ standard. The EPA designated the SJV as nonattainment for the 2006 $PM_{2.5}$ standard on November 13, 2009.
Key:
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns

On May 2014, the SJVAPCD formally requested that the EPA determine that the SJV has attained the federal 1-hour ozone standard based on the fact that the SJV has been meeting the 1-hour ozone standard based on the “expected exceedance days” test over the 2011 to 2013 three-year period air monitoring data.

Since 1992, the SJVAPCD air quality management strategies have focused on the 1-hour ozone standard, trying to achieve the emissions reductions needed to demonstrate attainment by developing and implementing attainment plans, adopting over 500 stringent rules, and supplementing its regulatory programs with a voluntary incentive program.

Ambient Air Quality

The SJVAPCD, CARB, National Park Service, and Santa Rosa Rancheria in Lemoore operate an extensive network of air monitoring stations in the SJV. The monitoring station network provides air quality monitoring data, including real-time meteorological data and ambient pollutant levels, as well as historical data. The network in the SJVAB consists of 36 monitoring stations, nine of which are located in western Kern County within the Project Area (SJVAPCD 2014). Table 4.3-3 presents the measured ambient pollutant concentrations and the exceedances of state and federal standards that have occurred at the above-mentioned monitoring stations from 2016 through 2018.

Table 4.3-3: Ambient Air Quality In Kern County – California And National Standards

CARB Air Monitoring Station	Number of Days Exceeding CAAQS[(a)]			Maximum ~~24-Hour~~ Daily Monitored Concentration ***State*** ~~(ppm or μg/m^3)~~			Number of Days Exceeding NAAQS[(a)]			***Maximum Daily Monitored Concentration National***		
	2016	**2017**	**2018**	**2016**	**2017**	**2018**	**2016**	**2017**	**2018**	***2016***	***2017***	***2018***
1-Hour Ozone (O_3) ***(ppm)***												
Arvin-Di Giorgio	21	13	15	0.110	0.111	0.110	0	0	0	*0.109*	*0.108*	*0.110*
Bakersfield 5558 California Ave.	0	11	8	0.097	0.100	0.101	0	0	0	*0.098*	*0.101*	*0.104*
Bakersfield Municipal Airport	8	9	9	0.099	0.101	0.103	0	0	0	*0.112*	*0.114*	*0.105*
Edison	14	12	27	0.109	0.112	0.120	0	0	0	*0.107*	*0.112*	*0.112*
Mojave 923 Poole Street	2	1	8	0.099	0.092	0.097	0	0	0	*0.103*	*0.097*	*0.103*
Maricopa Stanislaus St.	0	1	5	0.089	0.091	0.092	0	0	0	*0.090*	*0.092*	*0.096*
Oildale 3311 Manor St.	0	4	5	0.093	0.096	0.098	0	0	0	*0.093*	*0.098*	*0.100*
Shafter Walker St.	1	0	4	0.097	0.097	0.095	0	0	0	*0.096*	*0.095*	*0.096*
8-Hour Ozone (O_3) ***(ppm)***												
Arvin-Di Giorgio	82	81	69	0.096	0.096	0.098	78	73	65	*0.087*	*0.086*	*0.089*
Bakersfield 5558 California Ave.	63	87	64	0.094	0.095	0.095	60	85	60	*0.084*	*0.086*	*0.088*
Bakersfield Municipal Airport	66	57	59	0.101	0.101	0.096	63	55	54	*0.090*	*0.090*	*0.088*
Edison	68	76	87	0.096	0.095	0.098	64	74	82	*0.087*	*0.087*	*0.089*
Maricopa Stanislaus St.	55	42	46	0.087	0.089	0.090	50	38	42	*0.081*	*0.083*	*0.085*
Mojave 923 Poole Street	60	37	56	0.094	0.088	0.092	52	35	53	*0.084*	*0.081*	*0.085*
Oildale 3311 Manor St.	7	68	57	0.088	0.092	0.094	7	65	54	*0.077*	*0.079*	*0.082*
Shafter Walker St.	50	30	35	0.088	0.087	0.088	49	27	33	*0.081*	*0.080*	*0.081*
CO (carbon monoxide) No data.												
NO_2 ***1-hour (ppb)***												
Bakersfield 5558 California Ave.	0	0	0	~~57~~*58*	~~63~~*66*	~~65~~*61*	0	0	0	*58.1*	*66*	*61.5*
Bakersfield Municipal Airport	0	0	0	~~62~~*58*	~~59~~*62*	~~60~~*57*	*	*	0	*58.1*	*62.5*	*57.1*
Edison	0	0	0	~~38~~*45*	~~37~~*44*	~~37~~*42*	0	0	0	*45.7*	*44.9*	*42*
Shafter Walker St.	0	0	0	~~53~~*47*	~~45~~*47*	~~46~~*47*	0	0	0	*47.8*	*47.6*	*47.5*

Table 4.3-3: Ambient Air Quality In Kern County – California And National Standards

CARB Air Monitoring Station	Number of Days Exceeding CAAQS[(a)]			Maximum ~~24-Hour~~ Daily Monitored Concentration State ~~(ppm or μg/m³)~~			Number of Days Exceeding NAAQS[(a)]			Maximum Daily Monitored Concentration National		
	2016	2017	2018	2016	2017	2018	2016	2017	2018	2016	2017	2018
SO_X (sulfur oxides) No data.												
PM_{10} 24-hour ($\mu g/m^3$)												
Bakersfield 5558 California Ave.	21 / 121	16 / 99	13 / *	92.2	143.6	142	0	0	0	90.9	138.0	136.1
Bakersfield-Golden State Highway	26 / 158	24 / 146	27 / 163	91.6	165.1	159.0	0 / 0	1 / 6	1 / 7	91.6	158.2	155.2
Canebrake	1 / *	0 / 0	0 / *	52.9	40.2	43.7	0 / *	0 / 0	0 / 0	58.9	45.5	52.3
Mojave 923 Poole Street	18 / 19	10 / *	19 / *	130.3	85.7	86.5	0 / 0	0 / *	0 / 0	139.2	93.4	93.1
Oildale 3311 Manor St.	18 / *	80 / *	161 / *	88.4	210.0	179.0	0 / 0	0 / *	4 / 4	89.1	59.4	174.9
Ridgecrest 100 W. California Ave.	1 / *	0 / 0	1 / *	59.0	47.1	51.3	0 / 0	0 / 0	0 / *	66.2	48.8	53.2
Ridgecrest-Ward	0 / *	1 / *	3 / *	*	57.4	103.2	* / *	* / *	0 / 0	*	60.2	107.4
$PM_{2.5}$ 24-hour ($\mu g/m^3$)												
Bakersfield 5558 California Ave.	**	**	**	66.4	101.8	98.5	23 / 26	28 / 30	36 / 40	66.4	101.8	98.5
Bakersfield 410 E Planz Road	**	**	**	51.4	80.1	100.9	7 / *	10 / 32	9 / *	51.4	80.1	100.9
Bakersfield-Golden State Highway	**	**	**	53.9	74.3	99.1	7 / 22	9 / 30	11 / 34	53.9	74.3	99.1
Lebec-Beartrap Road	**	**	**	32.2	39.9	63.1	*	*	*	*	*	*
Mojave 923 Poole Street	**	**	**	25.7	26.9	39.0	0 / 0	0 / 0	2 / 2	25.7	26.9	39.0

Table 4.3-3: Ambient Air Quality In Kern County – California And National Standards

CARB Air Monitoring Station	Number of Days Exceeding CAAQS[(a)]			Maximum ~~24-Hour~~ Daily Monitored Concentration *State* ~~(ppm or μg/m^3)~~			Number of Days Exceeding NAAQS[(a)]			*Maximum Daily Monitored Concentration National*		
	2016	**2017**	**2018**	**2016**	**2017**	**2018**	**2016**	**2017**	**2018**	***2016***	***2017***	***2018***
Ridgecrest 100 W. California Ave.	**	**	**	25.8	13.3	4.5	0 */ **	0 */ **	0 */ **	*25.8*	*13.3*	*4.5*
Ridgecrest-Ward	**	**	**	*	10.9	37.2	0 */ **	0 */ **	1 */ 1*	**	*10.9*	*37.2*

Source: CARB n.d.

Notes:

[(a)] *Days exceeding CAAQS and NAAQS are measured number of days for O_3 and NO_2 and measured and estimated number of days, respectively, for PM_{10} and $PM_{2.5}$.*

* Insufficient data.

** No standard.

Key:

CAAQS = California Ambient Air Quality Standards

CARB = California Air Resources Board

NAAQS = National Ambient Air Quality Standards

NO_2 = nitrogen dioxide

PM_{10} = particulate matter less than 10 microns

$PM_{2.5}$ = particulate matter less than 2.5 microns

ppb = parts per billion

ppm = parts per million

μg/m^3 = micrograms per cubic meter

Criteria Air Pollutants and Health Effects

The following is a general description of the criteria air pollutants that are hazardous to human health and are regulated by federal and state ambient air quality standards or criteria for outdoor concentrations.

Ozone (O_3)

In the presence of ultraviolet radiation, nitrogen oxides (NO_X) and volatile organic compounds (VOCs)/reactive organic gases (ROG) go through a number of complex chemical reactions to form ozone. Table 4.3-3 includes the maximum hourly concentration and the number of days above the federal and State standards. As shown in Table 4.3-3, ozone continues to be above the State 1-hour and both the federal and State 8-hour ozone standards in many places in Kern County. The SJVAPCD attainment status for ozone is currently severe nonattainment for State 1-hour ozone; nonattainment/extreme for the federal 8-hour ozone; and nonattainment for State 8-hour ozone.

While ozone in the upper atmosphere protects the earth from harmful ultraviolet radiation, high concentrations of ground-level ozone can adversely affect the human respiratory system. Many respiratory ailments, as well as cardiovascular disease, are aggravated by exposure to high ozone levels. Ozone also damages natural ecosystems, such as forests and foothill communities; agricultural crops; and some man-made materials, such as rubber, paint, and plastic. High levels of ozone may negatively affect immune systems, making people more susceptible to respiratory illnesses, including bronchitis and pneumonia. Ozone also accelerates aging and exacerbates pre-existing asthma and bronchitis and, in cases with high concentrations, can lead to the development of asthma in active children. Active people, both children and adults, appear to be more at risk from ozone exposure than those with a low level of activity. Additionally, the elderly and those with respiratory disease are also considered sensitive populations for ozone.

People who work or play outdoors are at a greater risk for harmful health effects from ozone. Children and adolescents are also at greater risk because they are more likely than adults to spend time engaged in vigorous activities. Research indicates that children under 12 years of age spend nearly twice as much time outdoors daily than adults. Teenagers spend at least twice as much time as adults in active sports and outdoor activities. Also, children inhale more air per pound of body weight than adults, and they breathe more rapidly than adults. Children are less likely than adults to notice their own symptoms and avoid harmful exposures.

Ozone is an oxidant that is comparable to household bleach, which can kill living cells (such as germs or human skin cells) on contact. Ozone can damage the respiratory tract, causing inflammation and irritation, and it can induce symptoms such as coughing, chest tightness, shortness of breath, and worsening of asthmatic symptoms. Ozone in sufficient doses increases the permeability of lung cells, rendering them more susceptible to toxins and microorganisms. Exposure to levels of ozone above the current ambient air quality standard can lead to lung inflammation and lung tissue damage and a reduction in the amount of air inhaled into the lungs. Evidence has linked the onset of asthma to exposure to elevated ozone levels in exercising children.

Elevated ozone concentrations also reduce crop and timber yields, damage native plants, and damage materials such as rubber, paints, fabric, and plastics (American Lung Association 2015).

Carbon Monoxide (CO)

CO is a colorless, odorless gas produced by incomplete combustion of carbon-containing fuels (e.g., gasoline, diesel fuel, and biomass). CO is primarily a byproduct of motor vehicle exhaust, which contributes more than two-thirds of all CO emissions nationwide. In cities, automobile exhaust can cause as much as 95% of all CO emissions. These emissions can result in high concentrations of CO, particularly in local areas with heavy traffic congestion. Other sources of CO emissions include industrial processes and fuel combustion in sources such as boilers and incinerators. Despite an overall downward trend in concentrations and emissions of CO, some metropolitan areas still experience high levels of CO.

CO is essentially inert to plants and materials but can have significant effects on human health. CO enters the bloodstream and binds more readily to hemoglobin than oxygen, reducing the oxygen-carrying capacity of blood, thus reducing oxygen delivery to organs and tissues. The health threat from CO is most serious for those who suffer from cardiovascular disease. Healthy individuals are also affected, but only at higher levels of exposure. CO in the bloodstream reduces the blood's capacity for carrying oxygen to the heart, brain, and other parts of the body. Exposure to CO can cause chest pain in heart patients, headaches, and reduced mental alertness. At high concentrations, CO can cause heart difficulties in people with chronic diseases, and can impair mental abilities. Exposure to elevated CO levels is associated with visual impairment, reduced work capacity, reduced manual dexterity, poor learning ability, difficulty performing complex tasks, and in prolonged, enclosed exposure, death.

The adverse health effects associated with exposure to ambient and indoor concentrations of CO are related to concentration of carboxyhemoglobin in the blood. Health effects observed may include early onset of cardiovascular disease, behavioral impairment, decreased exercise performance of young healthy men, reduced birth weight, Sudden Infant Death Syndrome, and increased daily mortality rate. Most of the studies evaluating adverse health effects of CO on the central nervous system examine high-level poisoning. Such poisoning results in symptoms ranging from common flu and cold symptoms (shortness of breath on mild exertion, mild headaches, and nausea) to unconsciousness and death. It has been reported that there is an association between daily death rate and exposure to ambient CO in Los Angeles County, where it is postulated that a concentration of 20.2 parts per million (ppm) (the highest daily concentration recorded during a four-year period) contributed to 11 out of 159 deaths. Additional studies conducted in Los Angeles and in Sao Paulo, Brazil, also suggest a relationship between daily death rates and CO concentrations.

No CO data are available for Kern County for 2016 through 2018. The SJVAPCD attainment status for CO is unclassified/attainment for federal standards and unclassified for State standards

Nitrogen Dioxide (NO_2) and Oxides of Nitrogen (NO_X)

NO_2 is a reddish brown, highly reactive gas that is formed in the ambient air through the oxidation of nitric oxide. NO_X, the generic term for a group of highly reactive gases that contain nitrogen and oxygen in varying amounts, plays a major role in the formation of ozone, PM, and acid rain. NO_X emissions result from high-temperature combustion processes such as vehicle exhaust emissions and power plants. Home heaters and gas stoves can also produce substantial amounts of NO_2 in indoor settings. The majority of the NO_X emitted from combustion sources is in the form of nitrogen oxide (NO), while the balance is mainly NO_2. NO is oxidized by ozone in the atmosphere to NO_2 but some level of photochemical activity is needed for this conversion.

NO_X reacts with other pollutants to form, ground-level ozone, nitrate particles, acid aerosols, as well as NO_2, which cause respiratory problems. NO_X and the pollutants formed from NO_X can be transported over long distances, following the patterns of prevailing winds. Therefore, controlling NO_X is often most effective if done from a regional perspective, rather than focusing on the nearest sources.

Current scientific evidence links short-term NO_2 exposures, ranging from 30 minutes to 24 hours, with adverse respiratory effects including airway inflammation in healthy people and increased respiratory symptoms in people with asthma. Also, studies show a connection between breathing elevated short-term NO_2 concentrations, and increased visits to emergency departments and hospital admissions for respiratory issues, especially asthma (EPA 2014). NO_X are ozone precursors that combine with ROGs to form ozone. See the "Ozone (O_3)" section above for a discussion of the health effects of ozone.

Direct inhalation of NO_X can also cause a wide range of health effects. NO_X can irritate the lungs, cause lung damage, and lower resistance to respiratory infections such as influenza. Short-term exposures (e.g., less than 3 hours) to low levels of NO_2 (a subset of NO_X) may lead to changes in airway responsiveness and lung function in individuals with preexisting respiratory illnesses. These exposures may also increase respiratory illnesses in children. Long-term exposures to NO_2 may lead to increased susceptibility to respiratory infection and may cause irreversible alterations in lung structure. Other health effects associated with NO_X are an increase in the incidence of chronic bronchitis and lung irritation. Chronic exposure to NO_2 may lead to eye and mucus membrane aggravation, along with pulmonary dysfunction. NO_X can cause fading of textile dyes and additives, deterioration of cotton and nylon, and corrosion of metals due to production of particulate nitrates. Airborne NO_X can also impair visibility. NO_X is a major component of acid deposition in California. NO_X may affect both terrestrial and aquatic ecosystems. NO_X in the air is a potentially significant contributor to a number of environmental effects such as acid rain and eutrophication in coastal waters. Eutrophication occurs when a body of water suffers an increase in nutrients that reduce the amount of oxygen in the water, producing an environment that is destructive to fish and other animal life.

NO_2 is toxic to various animals as well as to humans. Its toxicity relates to its ability to combine with water to form nitric acid in the eye, lung, mucus membranes, and skin. Studies of the health impacts of NO_2 include experimental studies on animals, controlled laboratory studies on humans, and observational studies. In animals, long-term exposure to NO_2 increases susceptibility to respiratory infections, lowering their resistance to diseases such as pneumonia and influenza. Laboratory studies show susceptible humans, such as asthmatics, exposed to high concentrations of NO_2 can suffer lung irritation and, potentially, lung damage. Epidemiological studies have also shown associations between NO_2 concentrations and daily mortality from respiratory and cardiovascular causes, and with hospital admissions for respiratory conditions.

NO_X contribute to a wide range of environmental effects directly and when combined with other precursors in acid rain and ozone. Increased nitrogen inputs to terrestrial and wetland systems can lead to changes in plant species composition and diversity. Similarly, direct nitrogen inputs to aquatic ecosystems, such as those found in estuarine and coastal waters, can lead to eutrophication (a condition that promotes excessive algae growth, which can lead to a severe depletion of dissolved oxygen and increased levels of toxins harmful to aquatic life). Nitrogen, alone or in acid rain, also can acidify soils and surface waters. Acidification of soils causes the loss of essential plant nutrients and increased levels of soluble aluminum that are toxic to plants. Acidification of surface waters creates conditions of low pH and levels of aluminum that are toxic to fish and other aquatic organisms. NO_X also contribute to visibility impairment.

Table 4.3-3 summarizes NO_X data collected from Kern County monitoring stations. As indicated in the table, there have been no exceedances of the State standards and no data are available to determine exceedances under federal standards. The SJVAPCD attainment status for NO_2 is attainment/unclassified for federal and attainment for State standards.

Particulate Matter (PM_{10} and $PM_{2.5}$)

PM pollution consists of very small aerosol and solid particles suspended in the air. PM is a mixture of materials that can include acids (such as nitrates and sulfates), organic chemicals, smoke, soot, dust, salt, acids, metals, and allergens (such as fragments of pollen or mold spores). PM also forms when gases emitted from motor vehicles and industrial sources undergo chemical reactions in the atmosphere. The EPA currently regulates two types of PM emissions: PM_{10} and $PM_{2.5}$. PM_{10} refers to particles less than or equal to 10 microns in diameter and $PM_{2.5}$ refers to particles less than or equal to 2.5 microns in diameter.

Respirable Particulate Matter (PM_{10})

PM_{10} can be emitted directly or it can be formed many miles downwind from emission sources when various precursor pollutants interact in the atmosphere. Gaseous emissions of pollutants like NO_X, sulfur oxides (SO_X), VOC, and ammonia, given the right meteorological conditions, can form PM in the form of nitrates (NO_3), SO_4^{2-}, and organic particles. These pollutants are known as secondary particulates, because they are not directly emitted, but are formed through complex chemical reactions in the atmosphere. *Fugitive dust is mostly PM_{10}.*

Table 4.3-3 summarizes the ambient PM_{10} data collected from the Bakersfield 5558 California Avenue, Bakersfield Golden State Highway, Mojave 923 Poole Street, Oildale 3311 Manor Street, Canebrake, and Ridgecrest monitoring stations near the Project site and includes the maximum 24-hour and annual arithmetic average concentrations and the number of days above the federal and

State standards. The SJVAPCD attainment status for the federal PM_{10} standards is attainment and the State PM_{10} standard is nonattainment/severe.

Fine Particulate Matter ($PM_{2.5}$)

Table 4.3-3 summarizes the ambient fine PM data collected from monitoring stations located near the Project site. The SJVAPCD is in nonattainment for the federal and State $PM_{2.5}$ standards.

The size of particles is directly linked to their potential for causing health problems. PM_{10} particles pose problems because they can get deep into lungs and the bloodstream. Being even smaller, $PM_{2.5}$ will travel farther into the lungs *and can have more severe health impacts*. Exposure to *$PM_{2.5}$* ~~*such*~~ particles can affect both lungs and heart. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including (EPA 2014b):

- Premature death in people with heart or lung disease;
- Nonfatal heart attacks;
- Irregular heartbeat;
- Aggravated asthma;
- Decreased lung function; and
- Increased respiratory symptoms, such as irritation of the airways, coughing or difficulty breathing.

As a consequence of long-term exposure, $PM_{2.5}$ is a stronger risk factor for negative health effects than the coarse part of PM_{10} particles (particles in the 2.5 to 10 micron range). $PM_{2.5}$ constitutes a large portion of combustion particulates, including diesel particulate matter (DPM). The health risk from an inhaled dose of particulate matter depends on the size, composition, and concentration of the particles. Larger particles are generally filtered in the nose and throat, while particulate matter smaller than PM_{10} can settle in the bronchi and lungs and cause health problems. $PM_{2.5}$ can penetrate into the gas-exchange regions of the lungs, and ultrafine particles ($PM_{0.1}$) may pass through the lungs to affect other organs, such as the brain. Combustion particulate matter emissions, including diesel exhaust, often consists of particles smaller than 0.1 microns.

Long-term exposure to fine particulates may contribute to pulmonary and systemic oxidative stress, inflammation, progression of atherosclerosis, and risk of ischemic heart disease and death. Short-term exposure may contribute to complications of atherosclerosis, thrombosis, and acute ischemic events and may lead to increased mortality and morbidity from cardiovascular and respiratory diseases.

PM_{10} and $PM_{2.5}$ have fundamentally distinct physical and chemical properties and health effects, and thus are separately regulated and measured.

The section below entitled "Oil and Gas Operations and Health Effects" further discusses potential health effects of $PM_{2.5}$ emissions, among other things.

PM emissions may also lead to visibility impairment or aesthetic impacts. Visibility degradation is caused by the absorption and scattering of light by particles and gases in the atmosphere before it reaches the observer. As the number of fine particles increases, more light is absorbed and scattered, resulting in less clarity, color, and visual range. Particles that reduce visibility the most have diameters in the range of 0.1 to 1.0 microns. Some types of particles such as sulfates scatter more light, particularly during humid conditions. $PM_{2.5}$ can be transported to other locations and contribute to visibility problems. $PM_{2.5}$ can also affect vegetation by damaging foliage, disrupting the chemical processes within plants, reducing light adsorption, and disrupting photosynthesis (SJVAPCD 2018a, p. 3-5).

Sulfur Dioxide (SO_2)

SO_2 is typically emitted as a result of the combustion of a fuel containing sulfur. SO_2 is a colorless, irritating gas with a "rotten egg" smell formed primarily by the combustion of sulfur-containing fossil fuels. Fuels, such as natural gas, contain very little sulfur and consequently have very low SO_2 emissions when combusted. By contrast, fuels high in sulfur content, such as coal or heavy fuel oils, can emit very large amounts of SO_2 when combusted. Sources of SO_2 emissions come from every economic sector and include a wide variety of fuels, and other gases, liquids, and solids.

Current scientific evidence links short-term exposures to SO_2, ranging from 5 minutes to 24 hours, with an array of adverse respiratory effects including bronchoconstriction and increased asthma symptoms. These effects are particularly important for asthmatics at elevated ventilation rates (e.g., while exercising or playing; EPA 2015a). SO_X can also react with other compounds in the atmosphere to form small particles. These particles penetrate deeply into sensitive parts of the lungs and can cause or worsen respiratory disease, such as emphysema and bronchitis, and can aggravate existing heart disease, leading to increased hospital admissions and premature death. High concentrations of SO_2 can result in temporary breathing impairment for asthmatic children and adults who are active outdoors. Short-term exposures of asthmatic individuals to elevated SO_2 levels during moderate activity may result in breathing difficulties that can be accompanied by symptoms such as wheezing, chest tightness, or shortness of breath. Other effects that have been associated with longer-term exposures to high concentrations of SO_2, in conjunction with high levels of PM, include aggravation of existing cardiovascular disease, respiratory illness, and alterations in the lungs' defenses. SO_2 also is a major precursor to $PM_{2.5}$, which is a significant health concern, and is a primary contributor to poor visibility. (See also health effects under "Particulate Matter (PM_{10} and $PM_{2.5}$)," above.)

Exposure to high concentrations of SO_2 for short periods of time can constrict the bronchi and increase mucous flow, making breathing difficult. Additional health effects of SO_2 are listed below.

- SO_2 can immediately irritate the lung and throat at concentrations greater than 6 ppm in many people.

- SO_2 can impair the respiratory system's defenses against foreign particles and bacteria, when exposed to concentrations less than 6 ppm for longer time periods.
- SO_2 can enhance the harmful effects of ozone. (Combinations of the two gases at concentrations occasionally found in the ambient air appear to increase airway resistance to breathing.)
- SO_2 tends to have more toxic effects when acidic pollutants, liquid or solid aerosols, and particulates are also present. (In the 1950s and 1960s, thousands of excess deaths occurred in areas where SO_2 concentrations exceeded 1 ppm for a few days and other pollutants were also high.) Effects are more pronounced among mouth breathers (e.g., people who are exercising or who have head colds). These effects are listed below.
  - SO_2 concentrations can result in health problems, such as episodes of bronchitis requiring hospitalization associated with lower-level acid concentrations;
  - SO_2 concentrations have been linked to self-reported respiratory conditions, such as chronic cough and difficult breathing, associated with acid aerosol concentrations. (Asthmatic individuals are especially susceptible to these effects. The elderly and those with chronic respiratory conditions may also be affected at lower concentrations than the general population.);
  - Increased respiratory tract infections have been associated with longer-term, lower-level exposures to SO_2 and acid aerosols; and
  - SO_2 concentrations are also known to result in subjective symptoms, such as headaches and nausea, in the absence of pathological abnormalities, due to long-term exposure.
- SO_2 easily injures many plant species and varieties, both native and cultivated. Some of the most sensitive plants include various commercially valuable pines, legumes, red and black oaks, white ash, alfalfa and blackberry. The effects include:
  - Visible injury to the most sensitive plants at exposures as low as 0.12 ppm for 8 hours; and
  - Visible injury to many other plant types of intermediate sensitivity at exposures of 0.30 ppm for 8 hours.
- Positive benefits from low levels, in a very few species growing on sulfur deficient soils.
- Increases in SO_2 concentrations accelerate the corrosion of metals, probably through the formation of acids. (SO_2 is a major precursor to acidic deposition.) SO_2 may also damage stone and masonry, paint, various fibers, paper, leather, and electrical components.
- Increased SO_2 also contributes to impaired visibility. Particulate sulfate, much of which is derived from SO_2 emissions, is a major component of the complex total suspended particulate mixture.

As shown in Table 4.3-2, the SJVAPCD is designated attainment or unclassified for all SO_2 State and federal ambient air quality standards, respectively. Due to the restrictions for the use of high sulfur fuels, reduction in gasoline and diesel sulfur contents and reduction in SO_2 emissions from other industrial sources, such as refineries, SO_2 pollution is no longer a major air quality concern in most of California, including the Project site.

Lead (Pb)

Lead in the atmosphere occurs as PM. Main sources of lead emissions include leaded gasoline, battery manufacture, paint, ink, ceramics, ammunition, and secondary lead smelters. Prior to 1978, mobile emissions were the primary source of atmospheric lead. After the phase-out of leaded gasoline between 1978 and 1987, secondary lead smelters, battery recycling, and manufacturing facilities became lead emission sources of greater concern. Current federal standards for lead have no attainment designation, but areas lacking an attainment designation are treated as being in attainment of the standard. The SJVAPCD is designated as attainment for State standards and lead is no longer monitored in the ambient air of the SJVAPCD.

Exposure to lead occurs mainly through inhalation of air and ingestion of lead in food, water, soil, or dust. It accumulates in the blood, bones, and soft tissues and can adversely affect the kidneys, liver, nervous system, and other organs. Excessive exposure to lead may cause neurological impairments such as seizures, mental retardation, and behavioral disorders. Even at low doses, lead exposure is associated with damage to the nervous systems of fetuses and young children, resulting in learning deficits, and lowered IQ. Studies also show that lead may be a factor in high blood pressure and subsequent heart disease. Lead can also be deposited on the leaves of plants, presenting a hazard to grazing animals and humans through ingestion.

Reactive Organic Gases and Volatile Organic Compounds

Hydrocarbons are organic gases that are formed solely of hydrogen and carbon. There are several subsets of organic gases, including ROGs and VOCs. ROGs are a set of organic gases based on State rules and regulations. VOCs are similar to ROGs in that they include all organic gases except those exempted by federal law. The list of compounds excluded from the definition of VOC is provided by the SJVAPCD in SJVAPCD Rule 1020, Section 3.53. VOCs are emitted from incomplete combustion of hydrocarbons or other carbon-based fuels. Combustion engine exhaust, oil refineries, and oil-fueled power plants are the primary sources of hydrocarbons. Another source of hydrocarbons is evaporation from petroleum fuels, solvents, dry cleaning solutions, and paint.

The primary health effects of hydrocarbons result from the formation of ozone and its related health effects (see ozone health effects discussion above). High levels of hydrocarbons in the atmosphere can interfere with oxygen intake by reducing the amount of available oxygen through displacement. There are no separate federal or CAAQS for VOC. Carcinogenic forms of VOC are considered toxic air contaminants (TACs). An example is benzene, which is a carcinogen. The health effects of individual carcinogenic VOCs are described below under the heading "Toxic Air Contaminants."

Sulfates (SO_4^{2-})

Sulfates (SO_4^{2-}) are particulate products of combustion of sulfur-containing fossil fuels. When SO or SO_2 are exposed to oxygen they precipitate out into sulfates (SO_3 or SO_4^{2-}). Sulfates are the fully oxidized ionic form of sulfur. Sulfates occur in combination with metal and/or hydrogen ions. In California, emissions of sulfur compounds occur primarily from the combustion of petroleum-derived fuels (that is, gasoline and diesel fuel) that contain sulfur. This sulfur is oxidized to SO_2 during the combustion process and is subsequently converted to sulfate compounds in the atmosphere. The conversion of SO_2 to sulfates takes place relatively rapidly and completely in urban areas of California due to regional meteorological features.

CARB's sulfates standard is designed to prevent aggravation of respiratory symptoms. Effects of sulfate exposure at levels above the standard include a decrease in ventilatory function, aggravation of asthmatic symptoms, and an increased risk of cardiopulmonary disease. Sulfates are particularly effective in degrading visibility, and, because they are usually acidic, can harm ecosystems and damage materials and property.

Hydrogen Sulfide (H_2S)

H_2S is a colorless gas with the odor of rotten eggs. It is formed during bacterial decomposition of sulfur-containing organic substances. Also, it can be present in sewer gas and some natural gas, and can be emitted as the result of geothermal energy exploitation. In Kern County, H_2S is associated with geothermal activity, oil and gas production, refining, sewage treatment plants, and confined animal feeding operations.

Exposure to low concentrations of H_2S may irritate the eyes, nose, and throat. It may also cause difficulty in breathing for some asthmatics. Exposure to higher concentrations (above 100 ppm) of H_2S can cause olfactory fatigue, respiratory paralysis, and death. Brief exposures to high concentrations of H_2S, greater than 500 ppm, can cause a loss of consciousness. In most cases, the person appears to regain consciousness without any other effects. However, in many individuals, there may be permanent or long-term effects such as headaches, poor attention span, poor memory, and poor motor function. No health effects have been found in humans exposed to typical environmental concentrations of H_2S, 0.00011 to 0.00033 ppm. Deaths due to inhaling large amounts of H_2S have been reported in a variety of different work settings, including sewers, animal processing plants, waste dumps, sludge plants, oil and gas well drilling sites, and tanks and cesspools. Current federal standards for H_2S have no attainment designation and the SJVAPCD is designated as unclassified for State standards.

Visibility Reducing Particulates

Visibility reducing particles are a mixture of suspended PM consisting of dry solid fragments, solid cores with liquid coatings, and small droplets of liquid. These particles vary greatly in shape, size, and chemical composition, and can be made up of many different materials such as metals, soot, soil, dust, and salt.

This standard is a measure of visibility. The CARB does not yet have a measurement method that is accurate or precise enough to designate areas in the state as being in attainment or nonattainment. Thus, the entire state is unclassified.

Vinyl Chloride

Vinyl chloride monomer is a sweet smelling, colorless gas at ambient temperature. Landfills, publicly owned treatment works, and polyvinyl chloride (PVC) production are the major identified sources of vinyl chloride emissions in California. PVC can be fabricated into several products, such as pipes, pipefittings, and plastics. In humans, epidemiological studies of occupationally exposed workers have linked vinyl chloride exposure to development of liver angiosarcoma, which is a rare cancer, and have suggested a relationship between exposure and cancers of the lung and brain. There are currently no adopted ambient air standards for vinyl chloride.

Acute exposure of humans to high levels of vinyl chloride via inhalation has resulted in effects on the central nervous system, such as dizziness, drowsiness, headaches, and giddiness.

Vinyl chloride is reported to be slightly irritating to the eyes and respiratory tract in humans. Acute exposure to extremely high levels of vinyl chloride has caused loss of consciousness, irritation to the lungs and kidneys, and inhibition of blood clotting in humans and cardiac arrhythmias in animals.

Tests involving acute exposure of mice to vinyl chloride have shown a high acute toxicity from inhalation exposure to the substance. Long-term exposure to vinyl chloride concentrations has been linked with chronic health effects:

- Liver damage may result in humans from chronic exposure to vinyl chloride, through both inhalation and oral exposure.
- A small percentage of individuals occupationally exposed to high levels of vinyl chloride in air have developed a set of symptoms termed "vinyl chloride disease," which is characterized by Raynaud's phenomenon (fingers blanch and numbness and discomfort are experienced upon exposure to the cold), changes in the bones at the end of the fingers, joint and muscle pain, and scleroderma-like skin changes (thickening of the skin, decreased elasticity, and slight edema).
- Central nervous system effects (including dizziness, drowsiness, fatigue, headache, visual and/or hearing disturbances, memory loss, and sleep disturbances) as well as peripheral nervous system symptoms (peripheral neuropathy, tingling, numbness, weakness, and pain in fingers) have also been reported in workers exposed to vinyl chloride.

Several reproductive/developmental health effects from vinyl chloride exposure have been identified:

- Several case reports suggest that male sexual performance may be affected by vinyl chloride. However, these studies are limited by lack of quantitative exposure information and possible co-occurring exposure to other chemicals.

- Several epidemiological studies have reported an association between vinyl chloride exposure in pregnant women and an increased incidence of birth defects, while other studies have not reported similar findings.
- Epidemiological studies have suggested an association between men occupationally exposed to vinyl chloride and miscarriages in their wives' pregnancies, although other studies have not supported these findings.

Long-term exposure to vinyl chloride has also been identified as a cancer risk:

- Inhaled vinyl chloride has been shown to increase the risk of a rare form of liver cancer (angiosarcoma of the liver) in humans.
- Animal studies have shown that vinyl chloride, via inhalation, increases the incidence of angiosarcoma of the liver and cancer of the liver.

Toxic Air Contaminants (TACs)

Hazardous air pollutants (HAPs) is a term used by the federal Clean Air Act (CAA) that includes a variety of pollutants generated or emitted by industrial production activities. Called TACs under California law (see Health and Safety Code §§ 39650 et seq.), 10 pollutants have been identified through ambient air quality data as posing the most substantial health risk in California. Direct exposure to all of these pollutants has been shown to cause cancer, birth defects, damage to brain and nervous system and respiratory disorders. CARB provides emission inventories for TACs for only the larger air basins in the state.

Emissions from the top 10 TACs in the SJVAB are presented in Table 4.3-4. Similar to the criteria pollutants, TACs are emitted from stationary sources, areawide sources, mobile sources, and natural sources.

Table 4.3-4: 2009 Toxic Air Contaminant Emissions in the San Joaquin Valley Air Basin (tons per year)

Toxic Air Contaminant	Fresno	Kern (SJV)	Kings	Madera	Merced	San Joaquin	Stanislaus	Tulare	Total SJVAB
Acetaldehyde	320	360	136	82	143	258	155	148	1,603
Benzene	288	645	71	77	91	227	137	144	1,680
1,3-Butadiene	113	58	36	31	24	52	42	158	515
Carbon tetrachloride	<0.01	<0.01	0	0	0	0	0	0	0.01
Hexavalent chromium	0.04	0.03	<0.01	<0.01	<0.01	0.03	<0.01	<0.01	0.12
para-Dichlorobenzene	37	30	6	6	10	28	21	17	156
Formaldehyde	688	1,301	365	196	302	565	334	315	4,065
Methylene chloride	126	65	14	15	26	74	58	43	423

Table 4.3-4: 2009 Toxic Air Contaminant Emissions in the San Joaquin Valley Air Basin (tons per year)

Toxic Air Contaminant	Fresno	Kern (SJV)	Kings	Madera	Merced	San Joaquin	Stanislaus	Tulare	Total SJVAB
Perchloroethylene	170	96	22	25	36	117	89	62	617
Diesel particulate matter	1,159	1,640	319	273	658	993	531	500	6,073

Source: CARB 2009.
Key:
SJV = San Joaquin Valley
SJVAB = San Joaquin Valley Air Basin

The primary sources of benzene in the state include mobile sources (87%) and stationary sources (12%). Forty-six percent of hexavalent chromium emissions are from stationary sources such as electrical generation, aircraft and parts manufacturing, and fabricated metal produce manufacturing. The majority of 1,3-butadiene emissions are generated from incomplete combustion of gasoline and diesel fuels. Fifty-three percent of 1,3-butadiene emissions are from mobile sources and 21% are from area sources such as agricultural waste burning and open burning. Emissions of carbon tetrachloride are all produced by stationary sources such as chemical and allied produce manufacturers and petroleum refineries. Most of the emissions of para-dichlorobenzene are from consumer products such as non-aerosol insect repellents and solid/gel air fresheners. Eighty-two percent of formaldehyde emissions in California are from mobile sources, while 48% of methylene chloride emissions are from paint removers/strippers, automotive brake cleaners, and other consumer products. Perchloroethylene (PERC) is produced primarily from stationary sources such as dry cleaning plants and manufacture of aircraft parts and fabricated metal parts. Emissions of ~~*diesel particulate matter (*~~DPM~~)~~ are from mobile sources (98%) and stationary sources (1%). Para-dichlorobenzene and PERC are not relevant to oil and gas operations or energy generation in Kern County, since – as described above – both substances are commonly used in other industries; therefore, they are not discussed further in this section.

TACs do not have ambient air quality standards. Since no safe levels of TACs can be determined, there are no air quality standards for TACs. Instead, TAC impacts are evaluated by calculating the health risks associated with a given exposure. The requirements of the Air Toxic “Hot Spots” Information and Assessment Act apply to facilities that use, produce, or emit toxic chemicals. Facilities that are subject to the toxic emission inventory requirements of the Act must prepare and submit toxic emission inventory plans and reports, and periodically update those reports. Of the Kern County portion of the SJVAB, no facility in the SJVAPCD has reported cancer risk exceeding 10 in 1 million or a hazard index over 1.0 and, therefore, are not considered significant by the standards of the Hot Spots program in the SJVAPCD.

Health Effects and Risks of Toxic Air Contaminants

Acetaldehyde

Acetaldehyde is classified as a federal hazardous air pollutant and as a California TAC. Acetaldehyde is both directly emitted into the atmosphere and formed in the atmosphere from photochemical oxidation. Sources include combustion processes such as exhaust from mobile sources and fuel combustion from stationary internal combustion engines, boilers, and process heaters. In California, photochemical oxidation is the largest source of acetaldehyde concentrations in the ambient air. According to CARB 2009, approximately 85% of the emissions of acetaldehyde in the SJVAB are from mobile sources – primarily diesel-fueled. Area-wide sources, such as residential wood combustion, account for approximately 10%. However in general, acetaldehyde concentrations are higher indoors than outdoors, due in part to the abundance of combustion sources, such as cigarettes, fireplaces, and woodstoves.

The primary acute effect of inhalation exposure to acetaldehyde is irritation of the eyes, skin, and respiratory tract in humans. At higher exposure levels, erythema, coughing, pulmonary edema, and necrosis may also occur. Acute inhalation of acetaldehyde resulted in a depressed respiratory rate and elevated blood pressure in experimental animals. Tests involving acute exposure of rats, rabbits, and hamsters have demonstrated acetaldehyde to have low acute toxicity from inhalation and moderate acute toxicity from oral or dermal exposure.

Benzene

Benzene is highly carcinogenic and occurs throughout California. Benzene also has non-cancer-related health effects. The primary sources of benzene emissions in the SJVAB are mobile sources (approximately 67%) and stationary sources (approximately 32%). The mobile source emissions are primarily gasoline-fueled.

Brief inhalation exposure to high concentrations can cause central nervous system depression. Acute effects include central nervous system symptoms of nausea, tremors, drowsiness, dizziness, headache, intoxication, and unconsciousness. Neurological symptoms of inhalation exposure to benzene include drowsiness, dizziness, headaches, and unconsciousness in humans. Ingestion of large amounts of benzene may result in vomiting, dizziness, and convulsions in humans. Exposure to benzene in liquid and vapor form may irritate the skin, eyes, and upper respiratory tract in humans. Redness and blisters may result from dermal exposure to benzene.

Chronic inhalation of certain levels of benzene causes blood disorders in humans; specifically, benzene affects bone marrow (the tissues that produce blood cells). Aplastic anemia, excessive bleeding, and damage to the immune system (by changes in blood levels of antibodies and loss of white blood cells) may develop. Increased incidence of leukemia (cancer of the tissues that form white blood cells) has been observed in humans who have been occupationally exposed to benzene.

1,3-Butadiene (vinyl ethylene)

1,3-butadiene has been identified as a carcinogen in California. The majority of 1,3-butadiene emissions come from incomplete combustion of petroleum-based fuels. Mobile sources account for 48% of total SJVAB emissions. Area sources, such as agricultural waste burning, open burning associated with forest management, and woodstoves and fireplaces, contribute to approximately 27%. Since the majority of 1,3-butadiene emissions are from incomplete combustion of gasoline and diesel fuels, CARB's 1990 adopted low emission vehicle/clean fuels regulations and the 1996 Phase II reformulated gasoline regulations are expected to continue to reduce 1,3-butadiene emissions from cars and light-duty trucks as the fleet turns over and new low-emission vehicles are introduced into the fleet.

At very high levels, butadiene vapors cause neurological effects, such as blurred vision, fatigue, headache, and vertigo. Dermal exposure of humans to 1,3-butadiene causes a sensation of cold, followed by a burning sensation, which may lead to frostbite.

One epidemiological study reported that chronic (long-term) exposure to 1,3-butadiene by inhalation resulted in an increase in cardiovascular diseases, such as rheumatic and arteriosclerotic heart diseases, while other human studies have reported effects on the blood. A large epidemiological study of synthetic rubber industry workers demonstrated a consistent association between 1,3-butadiene exposure and occurrence of leukemia. Several epidemiological studies of workers in styrene-butadiene rubber factories have shown an increased incidence of respiratory, bladder, stomach, and lymphato-hematopoietic cancers. However, these studies are not sufficient to determine a causal association between 1,3-butadiene exposure and cancer, due to possible exposure to other chemicals and other confounding factors.

Carbon Tetrachloride (tetrachloromethane)

Carbon tetrachloride is a central nervous system depressant, which the EPA has classified as a Group B2, a probable human carcinogen. The primary sources of carbon tetrachloride in California include chemical and allied product manufacturers and petroleum refineries. Unlike many of the other TACs, carbon tetrachloride is emitted primarily by sources other than motor vehicles, and there are virtually no emissions within the SJVAB or California.

Acute inhalation and oral exposures to high levels of carbon tetrachloride have been observed primarily to damage the liver (swollen, tender liver, changes in enzyme levels, and jaundice) and kidneys (nephritis, nephrosis, proteinuria) of humans. Depression of the central nervous system has also been reported. Symptoms of acute exposure in humans include headache, weakness, lethargy, nausea, and vomiting. Delayed pulmonary edema (fluid in lungs) has been observed in humans who have been exposed to high levels of carbon tetrachloride by inhalation and ingestion, but this is believed to be due to injury to the kidney rather than direct action of carbon tetrachloride on the lung. Chronic inhalation or oral exposure to carbon tetrachloride produces liver and kidney damage in humans and animals.

Chromium, Hexavalent

Hexavalent chromium emissions come mainly from electric generation, aircraft and parts manufacturing, and fabricated metal produce manufacturing. In California, hexavalent chromium has been identified as a carcinogen. Epidemiological evidence suggests that exposure to inhaled hexavalent chromium may result in lung cancer.

The respiratory tract is the major target organ for chromium (VI) following inhalation exposure in humans. Other effects noted from acute inhalation exposure to very high concentrations of chromium (VI) include gastrointestinal and neurological effects, while dermal exposure causes skin burns in humans. Chronic inhalation exposure to chromium (VI) in humans results in effects on the respiratory tract, with perforations and ulcerations of the septum, bronchitis, decreased pulmonary function, pneumonia, asthma, and nasal itching and soreness reported. Chronic human exposure to high levels of chromium (VI) by inhalation or oral exposure may produce effects on the liver, kidney, gastrointestinal and immune systems, and possibly the blood.

para-Dichlorobenzene

In California, para-dichlorobenzene has been identified as a carcinogen. In addition to the carcinogenic impact, long-term inhalation exposure may affect the liver, skin, and central nervous system in humans. Para-dichlorobenzene is a chlorinated aromatic hydrocarbon (NPIC 2010). It was first registered for use in the United States in 1942, and it is sometimes called 1,4-dichlorobenzene. It is a fumigant insecticide and repellent. Para-dichlorobenzene turns directly from a solid into a gas, a process called sublimation.

The primary sources of para-dichlorobenzene include consumer products such as non-aerosol insect repellents and solid/gel air fresheners. These sources contribute to 97% of SJVAB para-dichlorobenzene emissions.

People who have been exposed to para-dichlorobenzene have experienced nausea, vomiting, dizziness, fatigue, and headaches. Para-dichlorobenzene vapor can also irritate the eyes and nasal passages. It may also cause kidney and liver damage in pets.

Formaldehyde

Formaldehyde is both directly emitted into the atmosphere and formed in the atmosphere as a result of photochemical oxidation. Photochemical oxidation is the largest source of formaldehyde concentrations in California ambient air. Directly emitted formaldehyde is a product of incomplete combustion. One of the primary sources of formaldehyde is vehicular exhaust. In fact approximately 76% of the formaldehyde emissions in the SJVAB are from mobile sources, of which the source is predominantly diesel-fueled. Formaldehyde is also used in resins, fumigants, and soil disinfectants, and it can be found in many consumer products as an antimicrobial agent.

The major toxic effects caused by acute formaldehyde exposure via inhalation are eye, nose, and throat irritation and effects on the nasal cavity. Other effects seen from exposure to high levels of formaldehyde in humans are coughing, wheezing, chest pains, and bronchitis. Chronic exposure to formaldehyde by inhalation in humans has been associated with respiratory symptoms and irritation of the eye, nose, and throat. Animal studies have reported effects on the nasal respiratory epithelium and lesions in the respiratory system from chronic inhalation exposure to formaldehyde.

Occupational studies have noted statistically significant associations between exposure to formaldehyde and increased incidence of lung and nasopharyngeal cancer. This evidence is considered to be "limited," rather than "sufficient," due to possible exposure to other agents that may have contributed to the excess cancers. The EPA considers formaldehyde to be a probable human carcinogen and has ranked it in EPA Group B1. In California, formaldehyde has been identified as a carcinogen.

Methylene Chloride (dichloromethane)

In California, methylene chloride has been identified as a carcinogen. In addition, chronic exposure can lead to bone marrow, hepatic, and renal toxicity. Methylene chloride is used as a solvent, a blowing and cleaning agent in the manufacture of polyurethane foam and plastic fabrication, and as a solvent in paint stripping operations. Approximately 80% of the SJVAB emissions of methylene chloride are from paint removers/strippers, automotive brake cleaners, and other consumer products. The statewide trend for methylene chloride shows that by comparing the statewide average methylene chloride concentration for 1990 to 1992 to that for 2005 to 2007 the result is a 77% decrease in both concentration and health risk.

Case studies of methylene chloride poisoning during paint stripping operations have demonstrated that inhalation exposure to extremely high levels of methylene chloride can be fatal to humans. Acute inhalation exposure to high levels of methylene chloride in humans has affected the central nervous system including decreased visual, auditory, and psychomotor functions, but these effects are reversible once exposure ceases. Methylene chloride also irritates the nose and throat at high concentrations. The major effects from chronic inhalation exposure to methylene chloride in humans are effects on the central nervous system, such as headaches, dizziness, nausea, and memory loss. In addition, chronic exposure can lead to bone marrow, hepatic, and renal toxicity. The EPA considers methylene chloride to be a probable human carcinogen and has ranked it in EPA Group B2. The State of California considers methylene chloride to be a carcinogen.

Perchloroethylene (tetrachloroethylene)

In California, PERC has been identified as a carcinogen. PERC vapors are irritating to the eyes and respiratory tract. Following chronic exposure, workers have shown signs of liver toxicity as well as kidney dysfunction and neurological disorders.

PERC is used as a solvent, primarily in dry cleaning operations. PERC is also used in degreasing operations, paints and coatings, adhesives, aerosols, specialty chemical production, printing inks, silicones, rug shampoos, and laboratory solvents. In the SJVAB, approximately 65% of the emissions of PERC are from such stationary sources as dry cleaning plants and manufacturers of aircraft parts and fabricated metal parts. Areawide sources contribute approximately 35%. In comparing the statewide PERC concentration for 1990 to 1992 to that for 2005 to 2007 the result is an 84% decrease in both concentration and health risk.

Breathing PERC for short periods of time can adversely affect the human nervous system. Effects range from dizziness, fatigue, headaches, and sweating to incoordination and unconsciousness. Contact with PERC liquid or vapor irritates the skin, eyes, nose, and throat. These effects are not likely to occur at levels of PERC that are normally found in the environment (EPA 1994).

Breathing PERC over longer periods of time can cause liver and kidney damage in humans. Workers exposed repeatedly to large amounts of PERC in air can also experience memory loss and confusion. Laboratory studies show that PERC causes kidney and liver damage and cancer in animals exposed repeatedly by inhalation and by mouth. Repeat exposure to large amounts of PERC in air may likewise cause cancer in humans.

Diesel Particulate Matter

Diesel exhaust and many individual substances contained in it (including arsenic, benzene, formaldehyde, and nickel) have the potential to contribute to mutations in cells that can lead to cancer. More than 40 diesel exhaust components are listed by the State and federal government as TACs or hazardous air pollutants, respectively. In California, particulate emissions from diesel-fueled engines has been identified as a carcinogen (17 California Code of Regulations [CCR] § 93000). Most researchers believe that diesel exhaust particles contribute the majority of the risk because the particles in the exhaust carry many harmful organics and metals.

DPM is emitted from both mobile and stationary sources. In the SJVAB, on-road diesel-fueled vehicles contribute approximately 61% of the total, with an additional 38% attributed to other diesel-fueled mobile sources such as construction and agricultural equipment.

Long-term exposure to diesel exhaust particles poses the highest cancer risk of any TAC evaluated by the California Office of Environmental Health Hazard Assessment (OEHHA). CARB estimates that about 70% of the cancer risk that the average Californian faces from breathing TACs stems from diesel exhaust particles.

In its comprehensive assessment of diesel exhaust, OEHHA analyzed more than 30 studies of people who worked around diesel equipment, including truck drivers, railroad workers, and equipment operators. The studies showed these workers were more likely than workers who were not exposed to diesel emissions to develop lung cancer. These studies provide strong evidence that long-term occupational exposure to diesel exhaust increases the risk of lung cancer. Using information from OEHHA's assessment, CARB estimates that diesel-particle levels measured in California's air in 2000 could cause 540 "excess" cancers (beyond what would occur if there were no diesel particles in the air) in a population of 1 million people over a 70-year lifetime (OEHHA 2002).

Other researchers and scientific organizations, including the National Institute for Occupational Safety and Health, have calculated similar cancer risks from diesel exhaust as those calculated by the OEHHA and CARB.

Exposure to diesel exhaust can have immediate health effects. Diesel exhaust can irritate the eyes, nose, throat, and lungs, and it can cause coughs, headaches, lightheadedness, and nausea. In studies with human volunteers, diesel exhaust particles made people with allergies more susceptible to the materials to which they are allergic, such as dust and pollen. Exposure to diesel exhaust also causes inflammation in the lungs, which may aggravate chronic respiratory symptoms and increase the frequency or intensity of asthma attacks.

Diesel engines are a major source of fine-particle pollution*, especially $PM_{2.5}$, which has specific health risks as noted previously in this chapter*. The elderly and people with emphysema, asthma, and chronic heart and lung disease are especially sensitive to fine-particle pollution.

Numerous studies have linked elevated particle levels in the air to increased hospital admissions, emergency room visits, asthma attacks, and premature deaths among people suffering from respiratory problems. Because children's lungs and respiratory systems are still developing, they are also more susceptible than healthy adults to fine particles. Exposure to fine particles is associated with increased frequency of childhood illnesses and can reduce lung function in children. In California, diesel exhaust particles have been identified as carcinogens.

Polycyclic Aromatic Hydrocarbons (PAHs)

The term polycyclic aromatic hydrocarbons (PAHs) refers to a group of several hundred chemically related, environmentally persistent organic compounds of various structures and varied toxicity. Most of them are formed by a process of thermal decomposition (pyrolysis) and subsequent recombination (pyrosynthesis) of organic molecules. PAHs enter the environment through various routes and are usually found as a mixture containing two or more of these compounds (e.g., soot). They have been shown to cause carcinogenic and mutagenic effects and are potent immunosuppressants. Effects have been documented on immune system development. They are byproducts of natural gas combustion.

Oil and Gas Operations and Health Effects

Close proximity to oil and gas wells may result in exposure to toxic contaminants in air and/or water. Many studies have investigated whether there is a link between oil and gas drilling and various health effects, such as asthma and other respiratory diseases, adverse birth outcomes, cancer, neurodevelopmental effects, cardiovascular disease, endocrine disruption, mental health effects, skin diseases, leukemia, migraines, fatigue, and throat irritation. These impacts may especially affect low-income communities and communities of color located in close proximity to oil and gas operations. (NRDC 2014; California Department of Public Health 2020.

A general discussion of various studies on this topic is presented below. It should be noted that the potential health effects from oil and gas operations are not new information and these potential impacts were incorporated into the analysis and mitigation measures in Section 4.3, Air Quality in the 2015 FEIR. The studies discussed below do not suggest that new mitigation, beyond the mitigation measures in this section, is necessary to mitigate potential health impacts from the Project. However, the studies, particularly Tran et al. (2020) and Gonzalez et al. (2020), add to the general knowledge of oil and gas health effects, particularly in Kern County specifically.

As to the other studies discussed below that are based on oil and gas operations outside of California, as explained in the California Council on Science and Technology Summary Report (CCST 2015), present-day hydraulic fracturing practice and geologic conditions in California differ from those in other states, and therefore, recent experiences with hydraulic fracturing in other states do not necessarily apply to California. Because California reservoirs are shallower and more permeable, wells tend to be shorter and near-vertical as opposed to horizontal. This means that wells in California take less time to drill and drilling time is the main driver of health risk from Project activities because it produces the most emissions of toxic DPM, which, as explained in Impact 4.3-3, below, accounts for 99 percent of the health risk from the Project. Thus, any reports or studies listed below that do not directly address California operations are less likely to support the link between health effects and oil and gas operations in Kern County. Further, as explained in Garabrant (2020) discussed below, the majority of the studies discussed below rely on correlative analyses that do not demonstrate causation between exposure to oil and gas activities and health effects, and thus the limitations identified by Garabrant (2020) in Tran (2020) and Gonzalez (2020) apply to many of the other studies described below.

California Studies

- ***Tran, K. V. et al. (2020). Residential Proximity to Oil and Gas Development and Birth Outcomes in California: A Retrospective Cohort Study of 2006–2015 Births.*** *Tran et al. (2020) conducted a retrospective cohort study of 2,918,089 births between January 2006 and December 2015 to mothers living within 10 kilometers (km) of at least one production well in the Sacramento Valley, San Joaquin Valley, South Central Coast, and South Coast Air Basins. Prenatal exposure to active oil and gas production was associated with adverse birth outcomes, with the strongest associations occurring with exposure to high production volume in rural areas. The authors based their analysis on total production volume from oil and gas wells but did not "directly measure … environmental impacts via, for example, air or drinking water monitoring near active or inactive wells." Further, the authors note that "there may be… individual factors that we could not measure in our study, such as maternal occupation, housing quality, indoor air quality, dependence on groundwater sources for drinking water…".*

- ***Gonzalez, D. J. X. et al. (2020). Oil and Gas Production and Spontaneous Preterm Birth in the San Joaquin Valley, CA.*** *Based on a case-control study of preterm births in San Joaquin Valley between 1998 and 2011, this study observed evidence that exposure to oil and gas well sites in the first and second trimesters is associated with increased odds of spontaneous preterm birth at 20 to 31 weeks. The study was limited in that it estimated exposure based on the number of wells within 10 km of the mother's residence, but did not assess actual exposure, it was not able to account for women who moved between conception and delivery or exposure at other residences, it was unable to account for births to the same mother, and it did not account for other sources of air pollution in the region.*

- ***Arbelaez, J. and B. Baizel. (2015). Californians at Risk: An Analysis of Health Threats from Oil and Gas Pollution in Two Communities.*** *This report conducted an investigation of health and air contaminants in Lost Hills, a community in Kern County, and the Upper Ojai Area, a* *community in Ventura County, by using a combination of air sampling data and self-reported information from health surveys. The FLIR (infrared) camera filming revealed visible emissions from several oil and gas facilities near the community and the air sampling revealed the presence of 15 compounds known to have negative effects on human health, as well as 11 compounds for which no health data was available. Residents also self-reported numerous health effects, including nosebleeds, headaches, sinus problems, and skin rashes. However, the report was limited in its testing, only capturing 5 Summa canister samples in Lost Hills and only receiving health information from 40 community members. In addition, the study notes that it was unable to collect ambient air samples in the community that would account for ambient pollutant levels from activities other than oil and gas operations, like wildfire, cattle production, agriculture, and other manufacturing or industrial activities; and that self-reported health issues could be due to other causes. Further, the study states that it was intended to obtain initial exploratory information for follow-up studies but was not meant to be a representative sample nor to establish statistical validity.*

- ***Garabrant, David H. (2020). Technical Memorandum to J. Dintzer.*** *According to this technical memorandum neither Tran et al. (2020) nor Gonzales et al. (2020) show a causal relationship between birth outcomes and proximity to oil and gas activities. Neither study measured actual exposure to oil and gas pollutants or contaminants. Garabrant (2020) also suggests that both studies have inadequate and invalidated exposure estimates. For example, Tran et al. (2020) counted the number of active wells within 1 km of a study participant's address and combined this with monthly production volume to create an exposure index, and Gonzalez et al. (2020) counted the number of wells within 10 km of a mother's residence and estimated exposure to each well as the inverse of the distance required. However, there was no assessment or measurements of any specific chemical or physical agent. Further, neither study accounted for confounding factors (such as smoking, narcotic and alcohol use, poverty, malnutrition, lack of access to health care, disease, pregnancy complications, or genetics), and both ignored hydrogeological or meteorological factors that could call into question exposure metrics and assumptions. Thus, Garabrant (2020) argues, neither study should be "relied upon in assessing health risks to California residents from oil and gas development."*

General Health Effects

- ***Garcia-Gonzales, D. et al. (2019). Hazardous Air Pollutants Associated with Upstream Oil and Natural Gas Development: An Examination of the Current Peer-reviewed Literature.*** *This study analyzed 37 articles, published between January 2012 and February 2018, that investigated HAPs near upstream oil and gas operations in the U.S. It did not find evidence to support the assumption that the hydraulic fracturing phase is associated with the highest risk of exposure. Rather, the production phase has the potential to emit the highest concentrations and most varied mixture of HAPs over the longest time period. It acknowledged that many studies suffered from "methodological limitations" that may have resulted in over- or under-estimated concentrations of summary findings. Also, 84% of the studies were conducted in other states and thus the general conclusions may not apply to Kern County.*

- ***Lim, G. Q. and John, K. (2020). Impact of Energy Production in the Barnett Shale Gas Region on the Measured Ambient Hydrocarbon Concentrations in Denton, Texas.*** *This study observed that shale gas activities in Denton, Texas (the Barnett Shale) had a strong influence on measured total non-methane organic carbon concentrations in the atmosphere. Unconventional oil and gas practices in Texas are not indicative of extraction practices and health impacts in Kern County.*

- ***McKenzie, L. M. et al. (2018a). Ambient Non-Methane Hydrocarbon Levels along Colorado's Northern Front Range: Acute and Chronic Health Risks.*** *This study characterized prenatal through adult health risks for acute (1-hour) and chronic (30-year) residential inhalation exposure scenarios to nonmethane hydrocarbons near oil and gas facilities in Colorado. The study used ambient air sample results to estimate risk for four different residential scenarios based on the distance of the nearest facility. This study involved many limitations, regarding which the authors note that "the uncertainties in our risk assessment are substantial, and the results are best suited for scoping policy and future studies."*

- ***Haley, M. et al. (2016). Adequacy of Current State Setbacks for Directional High-Volume Hydraulic Fracturing in the Marcellus, Barnett, and Niobrara Shale Plays.*** *This study reviewed geography, current statutes and regulations, evacuations, thermal modeling, air pollution studies, and vapor cloud modeling within the Marcellus, Barnett, and Niobrara Shale Plays to determine whether setbacks are adequate. The study found that setbacks may leave the public vulnerable to explosions, radiant heat, toxic gas clouds, and air pollution. The authors recognize that the study had a number of limitations. It was confined to three shale plans out of 20 in the continental United States; the thermal modeling was based on average gas well, but did not take into account local geography, weather patterns, engineering specifics of each particular well, or nearby structures that may have presented different results; and it focused on hydraulic fracturing practices in Texas, Pennsylvania, and Colorado, which are not the same as those conducted in California.*

- ***Los Angeles County Department of Public Health (2018). Public Health and Safety Risks of Oil and Gas Facilities in Los Angeles County.*** *This report investigates the question of whether to expand setbacks for oil and gas operations. It states that at 600 feet, additional mitigation may be needed for some, but not all, air quality impacts, noise, and odors; at 1,000 feet, additional mitigation may be needed for noise only during certain operations and for odors; and at 1,500 feet, additional mitigation is not needed. The report's information sets all have limitations. The epidemiological studies are described as "observational" and cannot determine causal relationships between exposure and health effects; the seven EIRs and two HRAs conducted for oil and gas production are not definitive in their findings regarding the role oil and gas production emissions play in air quality, odors, or noise impacts; and the neighborhood health investigations are anecdotal examples without any clear explanation of what laws, regulations, mitigation measures, or control techniques applied to or required of the facilities.*

- ***City of Los Angeles, Department of Public Works, Office of Petroleum and Natural Gas Administration and Safety (2019). Oil and Gas Health Report.*** *This report assesses whether setbacks of 1,500 feet from sensitive receptors for future oil and gas activities should be required. It summarizes prior HRAs; EIRs (including the 2015 FEIR); other reports on health risks from oil and gas activities; setbacks in other jurisdictions; and policy and legal statements. The report notes that "[t]here is a lack of empirical evidence correlating oil and gas operations within the City of Los Angeles to widespread negative health impacts" and that the review of scientific literature on the health impacts of oil and gas operations "was limited and inconclusive." It further notes that "conventional oil and gas production in the City of Los Angeles is completely different from the field specific geochemistries, high pressure and high flow rate oil and natural gas production in other states like Colorado, New Mexico, Oklahoma and Texas." The report does not reach a final determination on setback distances.*

Reviews of the 2015 California Council on Science and Technology Report

- ***Wong, Nicole J. (2017). Existing Scientific Literature on Setback Distances from Oil and Gas Development Sites.*** *Wong (2017) analyzed 14 studies of health impacts from exposures of unconventional natural gas development proximate to residences with a particular focus on South Los Angeles. The report recommends a 2,500-foot setback. Of the 14 studies, none were in California—where oil and gas operations can differ significantly from operations in other states—and the report notes that the studies found correlation between adverse health outcomes in some populations due to proximity to oil and gas operations, but could not prove causation.*

- ***Lewis, C. et al. (2018). Setback Distances for Unconventional Oil and Gas Development: Delphi Study Results.*** *This study's goal was to elicit expert consensus from 18 panelists (health care providers, public health practitioners, environmental advocates, and researchers) on appropriate setback distances from unconventional oil and gas development. The panel reached consensus (defined as greater than 75% agreement) that setbacks of less than ¼ mile should not be recommended. The study notes that its results "should be interpreted with caution, as they reflect the expert opinion of one panel." The study also acknowledged that "the panel would have been strengthened by representation from the petroleum industry," which may highlight biases and/or subjectivity on the part of panelists.*

- ***Webb, E. et al. (2017). Neurodevelopmental and Neurological Effects of Chemicals Associated with Unconventional Oil and Natural Gas Operations and Their Potential Effects on Infants and Children.*** *This study found that a number of harmful substances used in, or byproducts of, unconventional oil and natural gas development and operations may be linked to significant neurodevelopmental health problems in infants, children, and young adults. However, no assessment of causation was conducted.*

- ***Shonkoff, S. B. C. et al. (2019). Human Health and Oil and Gas Development: An Assessment of Chemical Usage in Oil and Gas Activities in the Los Angeles Basin and the City of Los Angeles.*** *This study analyzed chemical use in upstream oil and gas operations in*

Los Angeles and the South Coast Air Quality Management District and presented findings, conclusions, and research and policy recommendations. Although the study found that 324 chemicals of concern were found in oil and gas operations in the South Coast Air Quality Management District—140 in the City of Los Angeles—the authors caution that "[a]dditional information regarding environmental profiles, acute and chronic toxicity is needed before a more thorough assessment of risk can be completed." The authors acknowledge that "major data gaps exist regarding the identities of chemicals and associated environmental and toxicological profiles." While the study noted that a setback greater than 200 feet should be considered, it did not recommend any particular setback distance.

- ***Deziel, N. C. et al. (2020). Unconventional Oil and Gas Development and Health Outcomes: A Scoping Review of the Epidemiological Research.*** *Deziel et al. (2020) performed a literature search in MEDLINE and SCOPUS for epidemiological studies of exposure to unconventional oil and gas development and verified human health outcomes published through August 15, 2019. They identified 806 published articles, but after screening, selected 40 peer-reviewed articles for full text evaluation; of these, 29 met the authors' inclusion criteria. The authors found that 25 of the 29 studies reported at least one statistically significant association between exposure metrics and an adverse health outcome.*

Scientific Compilations

- ***Gorski, I., and B. S. Schwartz (2020). Environmental Health Concerns From Unconventional Natural Gas Development.*** *Gorski and Schwarts (2020) conducted a review of studies that summarizes the environmental and health-related impacts of unconventional natural gas development, such as horizontal drilling and hydraulic fracturing. The article reports that studies have reported associations between unconventional natural gas development and pregnancy and birth outcomes; migraine headache, chronic rhinosinusitis, severe fatigue, and other symptoms; asthma exacerbations; and psychological and stress-related concerns.*

- ***Concerned Health Professionals of New York and Physicians for Social Responsibility. (2019). Compendium of Scientific, Medical, and Media Findings Demonstrating Risks and Harms of Fracking.*** *This study is a compilation of evidence outlining the risks and harms of hydraulic fracturing sourced from peer-reviewed medical or scientific journals, investigative reports, and reports from government agencies. The study concludes that hydraulic fracturing poses threats to air, water, human health, public safety, community cohesion, long-term economic vitality, biodiversity, seismic stability, and climate stability.*

- ***Hays, J. and S. B. C. Shonkoff (2016). Toward an Understanding of the Environmental and Public Health Impacts of Unconventional Natural Gas Development: A Categorical Assessment of the Peer-Reviewed Scientific Literature, 2009-2015.*** *This study is an overview of peer-reviewed scientific literature from 2009 to 2015 relating to potential impacts of unconventional natural gas development on public health, and water and air quality. It demonstrates that the weight of the findings in the scientific literature indicate hazards and* *elevated risks to human health, as well as possible adverse health outcomes associated with unconventional oil and gas development. The authors acknowledge the study's limitations and state that "it is only intended to provide a snapshot of the scientific knowledge based on the available literature."*

Adverse Birth Outcome Studies

- ***Hill, E. L. (2018). Shale Gas Development and Infant Health: Evidence from Pennsylvania.*** *This study examined singleton births to mothers residing close to a shale gas well from 2003 to 2010 in Pennsylvania. It found evidence that drilling increased instances of low birth weight and decreased term birth weight on average among mothers living within 2.5 km of a well compared to mothers living within 2.5 km of a well. Unconventional natural gas practices in Pennsylvania are not indicative of practices in Kern County.*

- ***McKenzie, L. M. et al. (2019). Congenital Heart Defects and Intensity of Oil and Gas Well Site Activities in Early Pregnancy.*** *This study evaluated whether a relationship exists between maternal proximity to oil and gas activities and births with congenital heart defects). The population comprised live singleton births between 2005 and 2011 to mothers in 34 Colorado counties with 20 or more wells drilled from 2004 to 2011 per 10,000 births. It observed positive associations between the odds of a birth with a congenital heart defect and maternal exposure to oil and gas well activities in the second gestational month. However, "data on covariates were limited to information on birth certificates and thus we were not able to adjust for maternal health and nutrition that may have resulted in residual confounding of unknown bias." Further, Colorado extraction practices are not indicative of practices in Kern County.*

- ***Apergis, N., et al. (2019). Fracking and Infant Mortality: Fresh Evidence from Oklahoma.*** *This study explored the impact of shale gas and oil hydraulic fracturing wells on infants' health at birth in Oklahoma. It concluded that the closer the mother's residence at birth to hydraulic fracturing wells, the more infants had negative health experiences, and that results might be explained through the impact of hydraulic fracturing activities on the drinking quality index. This study is not an exposure assessment and thus does not represent a causal relationship. Also, unconventional natural gas practices in Oklahoma are different from those in California.*

- ***Caron-Beaudoin, E. et al. (2018). Gestational Exposure to Volatile Organic Compounds (VOCs) in Northeastern British Columbia, Canada: A Pilot Study.*** *Based on urine samples collected from pregnant women over five consecutive days, this study suggested higher benzene exposure in pregnant women from the Peace River Valley in Northeastern British Columbia—an area subject to hydraulic fracturing—than the general population. The authors acknowledged the study's "small sample size" and that "more extensive monitoring is warranted." Since based on Canadian health data and natural gas practices, it does not recognize the laws and regulations that apply in the U.S.*

- ***Currie, J. et al. (2017). Hydraulic Fracturing and Infant Health: New Evidence from Pennsylvania.*** *This study analyzed birth records in Pennsylvania from 2004 to 2013, comparing infants born to mothers living at different distances from active hydraulic fracturing* *sites and those born both before and after hydraulic fracturing was initiated at each site. It found evidence for negative health effects of in utero exposure to hydraulic fracturing sites within 3 km (9,842 feet) of a residence, with the largest impacts seen within 1 km (3,280 feet). The authors acknowledged the study's small sample size, which "limits our ability to probe the shape of the distance-exposure relationship and also limits out ability to obtain precise estimates from models with mother fixed effects" and that it was "constrained to focus on potential exposure to pollution (which is determined by the mother's residential location) rather than actual exposure that could be measured with personal monitoring devices."*

- ***Whitworth, K. W. et al. (2017). Maternal Residential Proximity to Unconventional Gas Development and Perinatal Outcomes among a Diverse Urban population in Texas.*** *Whitworth et al.(2017) conducted a retrospective birth cohort study among 158,894 women with a birth or fetal death from November 30, 2010, to November 29, 2012, in the Barnett Shale, in North Texas. The results of the study suggested an association between maternal residential proximity to unconventional natural gas activity and preterm birth and fetal death. The authors recognized that "the lack of detailed exposure assessment data remains a critical gap in understanding potential health risks associated with unconventional gas development activity. Exposure assessment studies would serve to quantify chemical and nonchemical stressors to which residents living near UGD are exposed, [and] validate UGD-activity metrics like the one used in this and previous studies …."*

- ***Whitworth, K. W. et al. (2018). Drilling and Production Activity Related to Unconventional Gas Development and Severity of Preterm Birth.*** *This study examined phase- and trimester-specific associations between unconventional gas development and preterm birth, using a case-control study of women with singleton births in the Barnett Shale area in Texas. The study observed little difference in trimester-specific risk associated with unconventional gas development, but suggested slightly greater risk of preterm birth associated with unconventional gas development earlier in pregnancy. The study did not include an exposure assessment, and the authors call for future "comprehensive studies to characterize specific exposures."*

- ***Casey, J. A. et al. (2016). Unconventional Natural Gas Development and Birth Outcomes in Pennsylvania, USA.*** *In adjusted models, this study found an association between unconventional natural gas development and preterm birth that increased across quartiles. It should be noted that this study is specific to Pennsylvania, as it involved a "retrospective cohort study" using electronic health records.*

Asthma and Respiratory Health Studies

- ***Shamasunder, B. et al. (2018). Community-Based Health and Exposure Study around Urban Oil Developments in South Los Angeles.*** *This study analyzed two oil drilling sites in Los Angeles and found that physician-diagnosed asthma rates were elevated in close proximity to drilling as compared to state- and county-level surveys. It involved an extremely limited sample size and was based on self-reported household health surveys. Further, these comparisons do* *not take into account competing sources of air pollution and other variables associated with asthma prevalence.*

- ***Peng, L. et al. (2018). The Health Implications of Unconventional Natural Gas Development in Pennsylvania.*** *This study investigated the health impacts of unconventional natural gas development of the Marcellus shale between 2001 and 2013 by merging well permit data with a database of inpatient hospital admissions. The study found an association between gas development and hospitalizations for pneumonia among the elderly but mixed results for other conditions (e.g., COPD, asthma). Notably, the study found no association of natural gas development and extraction with asthma, pneumonia, or upper respiratory infection among children aged 5- to 19.*

- ***Willis, M. D. et al. (2018). Unconventional Natural Gas Development and Pediatric Asthma Hospitalizations in Pennsylvania.*** *This study observed elevated odds of hospitalizations in Pennsylvania for the highest exposure category of pediatric patients exposed to unconventional natural gas development, as compared with their unexposed peers. Like other studies that use health data and residential proximity to natural gas development to establish correlation of health impacts, this study did not measure exposure to any agent or compound associated with known health impacts. The authors note that "[a]dditional work is needed to understand how UNGD air pollution may affect respiratory health, which could include detailed exposure assessments." Moreover, the study did not include a detailed analysis of other factors that can contribute to pediatric asthma (e.g., existing air quality from traffic and stationary sources, genetics, secondhand smoke, household mold, etc.).*

- ***Rasmussen, S. G. et al. (2016). Association between Unconventional Natural Gas Development in the Marcellus Shale and Asthma Exacerbations.*** *Rasumssen et al. (2016) conducted a nested case-control study comparing patients with asthma with and without exacerbations who were treated at the Geisinger Clinic from 2005 through 2012. It found that unconventional natural gas development in Pennsylvania was statistically associated with increased risk of mild, moderate, and severe asthma exacerbations. It acknowledged that health record data did not contain occupational information that may explain asthma exacerbation, only reflects patients' most recent address, so did not account for migration to and from areas with or without natural gas development, and was unable to differentiate between asthma exacerbations that were hospitalized versus those that occurred while hospitalized (or due to the stressors of being hospitalized).*

Cardiovascular Disease Studies

- ***McKenzie, L. M. et al. (2018b). Relationships between Indicators of Cardiovascular Disease and Intensity of Oil and Natural Gas Activity in Northeastern Colorado.*** *This study observed an association between the intensity of oil and gas activities in northeastern Colorado and several indicators of cardiovascular disease. The authors noted the following limitations: "Our cross sectional study design, small sample size, the potential for residual confounding, and lack of direct measures of noise and air pollution are important limitations of this analysis."*

- ***Ye, D. et al. (2017). Estimating Acute Cardiorespiratory Effects of Ambient Volatile Organic Compounds.*** *This study measured daily concentrations of 86 VOCs at a centrally located ambient monitoring site in Atlanta, and daily counts of emergency room visits for cardiovascular diseases and asthma. The study found that hydrocarbon groups (e.g., alkenes and alkyne) were associated with emergency room visits for cardiovascular diseases, while the ketone group was associated with emergency room visits for asthma. It should be noted that the hydrocarbons and VOC measured in this analysis are primarily emitted from traffic or other combustion sources and "Georgia does not have any natural gas proved reserves or production…" (EIA 2017).*

- ***Bard, D. et al. (2014). Traffic-Related Air Pollution and the Onset of Myocardial Infarction: Disclosing Benzene as a Trigger? A Small-Area Case-Crossover Study.*** *Bard et al. (2014) conducted a case crossover study from 2,134 myocardial infarction cases recorded by the local Coronary Heart Disease Registry (2000–2007) in the Strasbourg Metropolitan Area, France. It found a positive, statistically significant association between concentrations of benzene and the onset of myocardial infarction. However, the exposure was to traffic-related emissions, not those associated with natural gas production activities.*

- ***Harrison, R. J. (2016). Sudden Deaths among Oil and Gas Extraction Workers Resulting from Oxygen Deficiency and Inhalation of Hydrocarbon Gases and Vapors — United States, January 2010–March 2015.*** *This study explored nine deaths of oil and gas workers between January 2010 and March 2015, and whether exposure to hydrocarbon gases and vapors was a factor. Of the nine, three were in Colorado, three in North Dakota, and one each in Montana, Oklahoma, and Texas. On the whole, this study relates to worker hazards, particularly as they relate to opening thief hatches and manual gauging or sampling for hydrocarbon-containing tanks. It does not, however, speak to or apply to exposure risks for nearby receptors of oil and gas production facilities.*

- ***Villeneuve, P. J. et al. (2013). A Cohort Study of Intra-urban Variations in Volatile Organic Compounds and Mortality, Toronto, Canada.*** *This study investigated associations between long-term exposure to ambient VOCs and mortality among 58,760 residents of Toronto, Canada. The findings suggest that ambient concentrations of VOCs were associated with cancer mortality. This study did not focus on VOC exposure from oil and natural gas production facilities, but rather from traffic and non-traffic industrial sources.*

- ***Xu, X. et al. (2009). Association between Exposure to Alkylbenzenes and Cardiovascular Disease among National Health and Nutrition Examination Survey (NHANES) Participants.*** *This study used data from the 1999–2004 National Health and Nutrition Examination Survey to examine the relationship between alkylbenzenes (toluene, styrene, ethylbenzene, and the xylenes) and cardiovascular diseases. This cross-sectional study suggested that exposure to alkylbenzenes was positively associated with the prevalence of cardiovascular disease in the U.S. population aged 20 to 59. The study noted, however, that biological mechanisms underlying exposure to alkylbenzenes and cardiovascular disease remains unclear. Limitations include the fact that information on cardiovascular disease was* *collected via interview questionnaires and that "other sources of alkylbenzenes, besides traffic emission related sources, are responsible for the associations …"*

Endocrine Disrupting Chemical Studies

- ***Bolden, A. L. et al. (2018). Exploring the Endocrine Activity of Air Pollutants Associated with Unconventional Oil and Gas Extraction.*** *This study comprised a literature review to identify air pollutants associated with unconventional oil and gas development. It identified 106 airborne chemicals detected in two or more studies—including ethane, benzene, and n-pentane—at least 21 of which are known endocrine disruptors, and several others identified in literature as affecting reproduction, development, and neurophysiological function.*

Mental Health Studies

- ***Casey, J. A. et al. (2018). Associations of Unconventional Natural Gas Development with Depression Symptoms and Disordered sleep in Pennsylvania.*** *This study evaluated the association of unconventional natural gas development with depression symptoms and disordered sleep diagnoses using a patient questionnaire and health record data among adult primary care patients at the Geisinger Clinic in Pennsylvania. The study found an association between proximity to unconventional natural gas development and depression symptoms, but no association with disordered sleep diagnoses. The findings were limited as participants tended to be sicker than the general population as the study's survey was designed to over-sample patients with nasal and sinus symptoms. Noting this, the authors stated that: "this could limit the generalizability of our results as sicker individuals may represent vulnerable populations who might more readily develop UNGD-related depression or sleep problems."*

- ***Sangaramoorthy, T. et al. (2016). Place-based Perceptions of the Impacts of Fracking along the Marcellus Shale.*** *This study examined community perspectives and experiences with hydraulic fracturing practices in West Virginia to investigate potential health impacts associated with hydraulic fracturing in Maryland. The researchers held two focus groups with community residents and conducted field observations in impacted areas. The study did not have any conclusive health-related findings, but rather called for future work to consider the "complex linkages between social disruption, environmental impacts, and health outcomes …."*

- ***Casey, J. et al. (2019). Unconventional Natural Gas Development and Adverse Birth outcomes in Pennsylvania: The Potential Mediating Role of Antenatal Anxiety and Depression.*** *Casey et al. (2019) utilized a retrospective cohort study to evaluate associations between unconventional natural gas development in Pennsylvania and antenatal anxiety and depression, preterm birth (< 37 weeks gestation), and reduced term birth weight. Although the study suggested an association between proximity to more productive unconventional natural gas development activity and an increased risk of antenatal anxiety and depression, this increased risk did not appear to mediate the association between unconventional natural gas development and preterm birth or reduced term birth weight. The study acknowledged the* *possibility "that there are more relevant factors for understanding the association between [unconventional natural gas development] and mental health outcomes."*

Other Adverse Health Outcomes

- ***Denham, A. et al. (2019). Unconventional Natural Gas Development and Hospitalizations: Evidence from Pennsylvania, United States, 2003–2014.*** *This study examined the relationships between short-term and long-term exposures to unconventional natural gas development and county hospitalization rates for a variety of diseases, and found evidence of an association of cumulative well density (per square kilometer) with genitourinary- and skin-related hospitalization rates. Because the information was limited to hospital discharge data and not patient addresses, it was "unable to utilize more precise exposure measures based on distance between place of residence and wells." As an ecological study, it did not allow for causal inference, meaning it could not definitively say that exposure to unconventional natural gas development caused increased hospitalization rates.*

- ***McKenzie, L. M. et al. (2017). Childhood Hematologic Cancer and Residential Proximity to Oil and Gas Development.*** *This study explored whether residential proximity to oil and gas development was associated with risk for hematologic cancers using a registry-based case-control study. It found that young individuals in Colorado with Non-Hodgkin lymphoma were more likely to live within 16.1 km of an active oil and gas well than children diagnosed with a non-hematologic cancer. The study found no indication of an association between Non-Hodgkin lymphoma and density of active oil and gas wells. The authors noted some limitations of the study, such as an "inability to adjust for early common infections, nutrition, family history of neoplasms, water source, proximity to other pollutants, and daycare attendance, as well as individual income [which] may have resulted in residual confounding." Further, the authors were unable to adjust for maternal smoking during pregnancy, and acknowledged that children with Non-Hodgkin lymphoma are 22% more likely than controls to have a mother who smoked during pregnancy.*

- ***Weinberger, B. et al. (2017). Health Symptoms in Residents Living near Shale Gas Activity: A Retrospective Record Review from the Environmental Health Project.*** *This study reviewed health assessments between February 2012 and October 2015 for 51 adults in Pennsylvania who lived within 1 km (3,281 feet) of an unconventional natural gas well. The subjects of the study reported at least one symptom on their health assessment, and denied occupation exposure related to natural gas extraction. Limitations include use of self-report data and a "convenience sample" of only 51 adults.*

- ***Tustin, A. W. et al. (2016). Associations between Unconventional Natural Gas Development and Nasal and Sinus, Migraine Headache, and Fatigue Symptoms in Pennsylvania.*** *Using a self-administered questionnaire to 23,700 adult patients of the Geisinger Clinic in Pennsylvania, this study found that unconventional natural gas development activity was associated with nasal and sinus symptoms, migraine headache, and higher levels of fatigue. It has several limitations—chiefly, evidence of selection bias because survey participants had* *poorer health than non-responders. Further, participants' exposure could have been affected by unmeasured factors such as "occupation, travel and time spent outdoors" or other factors. Overall, it does not present definitive proof that proximity to unconventional natural gas development causes health impacts.*

- ***Jemielita, T. et al. (2015). Unconventional Gas and Oil Drilling Is Associated with Increased Hospital Utilization Rates.*** *This study correlated healthcare use by zip code from 2007 to 2011 in Pennsylvania, primarily based on inpatient discharge databases from the Pennsylvania Healthcare Cost Containment Council, with active wells by zip code. The study found an association with hydraulic fracturing (as determined by well number or density) and cardiology inpatient prevalence rates, and an association between well density and neurology inpatient prevalence rates. The authors note, however, that the precise cause for the increase in inpatient rates within specific medical categories remains unknown. Further, the study examined a relatively short time interval, and as such, it is impossible to know whether the findings will be validated over longer periods of observation.*

- ***Steinzor, N. et al. (2013). Investigating Links between Shale Gas Development and Health Impacts through a Community Survey Project in Pennsylvania.*** *This study comprised a self-reporting health survey and environmental testing that investigated the extent and types of health symptoms experienced by people living in gas development areas in Pennsylvania. Participants were given the option of completing surveys anonymously, which some chose to do, and in some cases, spouses, parents, or neighbors completed surveys for participants. This study acknowledged that "the data did not prove that living closer to oil and gas facilities caused health problems," or "definitive proof of cause and effect." Rather, the study suggested an association between health symptoms and proximity to oil and natural gas facilities.*

- ***Paulik, B. L. (2018). Environmental and Individual PAH Exposures near Rural Natural Gas Extraction.*** *This study found evidence that PAH concentrations were significantly higher at active natural gas extraction sites in Eastern Ohio than proposed sites, suggesting that living or working near an active natural gas extraction site may increase exposure to PAHs. The researchers placed "silicon wristbands" on study participants to assess exposure to PAHs. However, the sample size was small and study participants were selected from a group of volunteers. Thus, the findings of this study may not reflect the entire population in regions subject to active natural gas extraction sties. The study also did not capture how much time participants spent at active well sites each day, which may lead to exaggerated results if participants were working in close proximity to well sites or were prone to other sources of PAHs at other locations.*

- ***American Lung Association (2020). State of the Air 2020.*** *This report includes lists of the top 25 most polluted cities in the United States for (i) 24-hour* $PM_{2.5}$*, (ii) annual* $PM_{2.5}$*, and (iii) ozone. Cities were ranked using the highest weighted average for any county within that Combined Metropolitan Statistical Area or Metropolitan Statistical Area. The report focuses on a number of "threats" that could worsen air quality in such cities, such as weakening the Clean Air Act, weakening vehicle emission standards, removing methane emission limits, etc.*

Environmental Justice

- ***Johnston, J., and L. Cushing (2020). Chemical Exposures, Health, and Environmental Justice in Communities Living on the Fenceline of Industry.*** *This study describes recent developments in assessing pollutant exposures and health threats from industrial facilities using or releasing synthetic chemicals to nearby communities. None of the California-based studies reviewed in this study focused particularly on chemical exposure or health effects from oil and natural gas development. The only California-based studies cited involved CalEnviroScreen 1.1 (Cushing et al. 2015); health burdens near oil refinery fires in Richmond, California (Remy et al. 2019); legacy pollution in communities near lead-acid battery smelter (Johnson, J. E. et al. 2019); retirement of coal and oil power plants in California and associated preterm births (Casey, J. A. et al. 2018); and a case study of the Southern California environmental justice collaborative (Petersen et al. 2006).*

- ***Morello-Frosch, R. et al. (2011). Understanding The Cumulative Impacts of Inequities In Environmental Health: Implications for Policy.*** *This study synthesized existing scientific evidence regarding the cumulative health implications of higher rates of exposure to environmental hazards, along with individual biological susceptibility and social vulnerability. It concludes that current environmental policy, which is focused on pollutants and their sources, should be broadened to take into account the cumulative impact of exposures and vulnerabilities encountered by people who live in neighborhoods consisting largely of racial or ethnic minorities or people of low socioeconomic status. While the study states that prior research shows a correlation of disadvantaged communities in proximity to industrial facilities, it does not specifically mention oil and natural gas exploration and extraction activities.*

Other Health Effects

Valley Fever

Valley Fever or coccidioidomycosis is one of the most studied and oldest known fungal infections. Coccidioidomycosis was first discovered in the early 1890s in Domingo Ezcurra, an Argentinean soldier, and in 1900 was established as a fungal disease. After an outbreak in the 1930s in the SJV of California, this disease was given its nickname “San Joaquin Valley Fever,” often shortened further to “Valley Fever” (Los Angeles County Department of Health Services, Public Health 2004).

Valley Fever is primarily a disease of the lungs caused by inhalation of spores of the *Coccidioides immitis* fungus. The *Coccidioides* fungus resides in the soil in southwestern United States, northern Mexico, and parts of Central and South America. When weather and moisture conditions are favorable, the fungus “blooms” and forms many tiny spores that lie dormant in the soil. The spores are found in the top few inches of soil, become airborne when the soil is disturbed by wind, vehicles, excavation, or other ground-moving activities, and are subsequently inhaled into the lungs. After the fungal spores have settled in the lungs, they change into a multicellular structure called a spherule. Fungal growth in the lungs occurs as the spherule grows and bursts, releasing endospores, which then develop into more spherules.

Infection occurs when the spores of the fungus become airborne and are inhaled. The fungal spores become airborne when contaminated soil is disturbed by human activities, such as construction and agricultural activities, and natural phenomenon, such as windstorms, dust storms, and earthquakes.

Valley Fever symptoms generally occur within two to three weeks of exposure. Approximately 60% of Valley Fever cases are mild and display flu-like symptoms or no symptoms at all. The remainder developed flu-like symptoms (fatigue, cough, chest pain, fever, rash, headache, and joint aches) that can last for a month and tiredness that can sometimes last for longer than a few weeks. In some cases, painful red bumps may develop. A small percentage of infected persons (<1%) can develop disseminated disease that spreads outside the lungs to the brain, bone, and skin. Without proper treatment, Valley Fever can lead to severe pneumonia, meningitis, and even death. Symptoms may appear between one to four weeks after exposure.

One important fact to mention is that these symptoms are not unique to Valley Fever and may be caused by other illnesses as well. Identifying and confirming this disease requires specific laboratory tests such as: (1) microscopic identification of the fungal spherules in the infected tissue, sputum, or body fluid sample; (2) growing a culture of *Coccidioides immitis* from a tissue specimen, sputum, or body fluid; (3) detecting antibodies (serological tests specifically for Valley Fever) against the fungus in blood serum or other body fluids; and (4) administering the Valley Fever skin test (called coccidioidin or spherulin), which indicates prior exposure to the fungus.

Valley Fever is not contagious and, therefore, cannot be passed from person to person. Most of those who are infected will recover without treatment within six months and will have a life-long immunity to the fungal spores. In severe cases, such as patients with rapid and extensive primary illness, those who are at risk for dissemination of disease, and those who have disseminated disease, antifungal drug therapy is used. Only 1% to 2% of those exposed who seek medical attention will develop a disease that disseminates (spreads) to other parts of the body other than the lungs. Table 4.3-5 presents the various infection classifications and normal diagnostic spread of Valley Fever Cases.

Table 4.3-5: Range of Valley Fever Cases

Infection Classification	Percent of Total Diagnosed Cases
Asymptomatic infections	60
Infections that resolve spontaneously (with lifelong immunity)	35
Chronic disease or disease disseminated throughout the body	Up to 5
Meningeal infection (affecting brain and/or spinal cord and requiring lifetime treatment)	0.15–0.75

Source: Hector 2005.

Factors that affect the susceptibility to coccidioidal dissemination are race, sex, pregnancy, age, and immunosuppression. According to data gathered by the Kern County Public Health Services Department, Hispanic/Latino-Americans are 3.4 times more likely than whites to develop coccidioidal dissemination, African-Americans are 13.7 times more likely, and Filipinos are 175.5 times more likely. Regarding the number of deaths attributed to the disease, compared to whites, the number of Hispanic/Latino is five times greater; African Americans, 23.3 times greater; and Filipinos, 191.4 times greater. In addition, residents new to the SJV are at a higher risk of infection due primarily to low immunity to this particular fungus (see also KCPHS 2014).

COVID-19

COVID-19 is an infectious disease caused by the SARS-CoV-2 strain of coronavirus, a group of related RNA viruses that cause diseases in mammals and birds. Coronaviruses cause respiratory tract infections that can range from mild to lethal and include some causes of the common cold, while more lethal varieties can cause SARS, MERS, and COVID-19. COVID-19 can cause fever, cough, fatigue, shortness of breath, and loss of smell and taste. While the majority of cases result in mild symptoms, some progress to acute respiratory distress syndrome, multi-organ failure, septic shock, and blood clots. COVID-19 primarily spreads through close contact with an infected person and via respiratory droplets produced from coughs or sneezes. The droplets usually fall to the ground or onto surfaces rather than travelling through air over long distances. Less commonly, people may become infected by touching a contaminated surface and then touching their face. COVID-19 is most contagious during the first three days after the onset of symptoms, although spread is possible before symptoms appear, and from people who do not show symptoms.

Recommended measures to prevent infection include frequent hand washing, maintaining physical distance from others, quarantine, covering coughs, and keeping unwashed hands away from the face. The use of cloth face coverings has been recommended by health officials in public settings to minimize the risks of transmission. Currently, there are no vaccines nor specific antiviral treatments for COVID-19. Management involves the treatment of symptoms, supportive care, isolation, and experimental measures. The World Health Organization (WHO) declared the COVID-19 outbreak a public health emergency of international concern on January 30, 2020, and a pandemic on March 11, 2020. Local transmission of the disease has occurred in most countries across all six WHO regions.

A small increase in long-term exposure to $PM_{2.5}$ has been found to lead to an increase in the death rate of COVID-19 (Harvard School of Public Health 2020). *The study suggests that long-term exposure to $PM_{2.5}$ is associated with higher COVID-19 mortality rates, even after adjustment for a wide range of socioeconomic, demographic, weather, behavioral, epidemic stage, and healthcare-related confounders.* Long-term exposure to $PM_{2.5}$ emissions may also add to the potential susceptibility for COVID-19. *People of color may live in areas already burdened by air pollution (NRDC 2014,). People of color may also have a higher risk of getting sick or dying from COVID-19 (California Department of Public Health 2020).*

~~*As of June 23, 2020, Kern County had 4,049 cases of COVID-19 with 60 deaths out of 900,202 residents (Kern County 2020). Over 64% of County residents who have COVID-19 are Hispanic,*~~

~~*while 13% are White, 13% are unknown, 3% are Black, 3% are Asian, and 1% are other.*~~ *As of October 2, 2020, Kern County had 32,184 cases of COVID-19, with 371 deaths out of 900,202 residents. Fifty-five percent of County residents who have had COVID-19 are Hispanic, while 22% are unknown, 12% are White, 5% are other, 4% are Black, and 2% are Asian. (Kern County 2020)*

Asbestos

Asbestos is the name given to a number of naturally occurring fibrous silicate minerals that have been mined for their useful properties such as thermal insulation, chemical and thermal stability, and high tensile strength. The three most common types of asbestos are chrysotile, amosite, and crocidolite. Ultramafic, serpentinized rock is closely associated with asbestos and is chemically composed of the following list of minerals:

- Antigorite, $(Mg, Fe)_3Si_2O_5(OH)_4$;
- Clinochrysotile, $Mg_3Si_2O_5(OH)_4$;
- Lizardite, $Mg_3Si_2O_5(OH)_4$;
- Orthrochrysotile, $Mg_3Si_2O_5(OH)_4$; and
- Parachrsotile, $(Mg, Fe)_3Si_2O_5(OH)_4$.

These minerals have essentially the same chemistry but different structures. Chrysotile minerals are more likely to form serpentinite asbestos; however, serpentinite is uncommon to sedimentary soil found in the proposed Project Area.

Asbestos can adversely affect humans only in its fibrous form, and these fibers must be broken and dispersed into the air and then inhaled. During geological processes (e.g., fault movement), the asbestos mineral can be crushed, causing it to become airborne. It also enters the air or water from the breakdown of natural deposits. Constant exposure to asbestos at high levels on a regular basis may cause cancer in humans. The two most common forms of cancer are lung cancer and mesothelioma, a rare cancer of the lining that covers the lungs and stomach.

Chrysotile, also known as white asbestos, is the most common type of asbestos found in buildings. Chrysotile makes up approximately 90% to 95% of all asbestos contained in buildings in the United States. Project construction sometimes requires the demolition of existing buildings where construction occurs. Buildings often include materials containing asbestos. Most demolitions and many renovations are subject to an asbestos inspection prior to start of activity. The demolition, renovation, or removal of asbestos-containing building materials is subject to the limitations of the National Emissions Standards for Hazardous Air Pollutants (NESHAP) regulations as listed in the Code of Federal Regulations (CFR) requiring notification, inspection, and compliance with local air district regulations. The SJVAPCD requires compliance with NESHAP and has adopted Rule 4002.

In addition, asbestos is also found in a natural state. Exposure and disturbance of rock and soil that naturally contains asbestos can result in the release of fibers to the air and consequent exposure to the public. Asbestos most commonly occurs in ultramafic rock that has undergone partial or complete alteration to serpentine rock (serpentinite) and often contains chrysotile asbestos. In addition, another form of asbestos, tremolite, can be found associated with ultramafic rock, particularly near faults. Sources of asbestos emissions include unpaved roads or driveways surfaced with ultramafic rock, construction activities in ultramafic rock deposits, or rock quarrying activities where ultramafic rock is present.

To address some of the health concerns associated with exposure to asbestos from these activities, CARB has adopted two Airborne Toxic Control Measures (ATCMs). CARB has an ATCM for construction, grading, quarrying, and surface mining operations requiring the implementation of mitigation measures to minimize emissions of asbestos-laden dust. This ATCM applies to road construction and maintenance, construction and grading operations, and quarries and surface mines when the activity occurs in an area where naturally occurring asbestos (NOA) is likely to be found. Areas are subject to the regulation if they are identified on maps published by the California Department of Conservation as ultramafic rock units or if the Air Pollution Control Officer (APCO) or owner/operator has knowledge of the presence of ultramafic rock, serpentine, or NOA on the site. The ATCM also applies if ultramafic rock, serpentine, or asbestos is discovered during any operation or activity.

In addition, CARB has an ATCM for surfacing applications. This ATCM applies to any person who produces, sells, supplies, offers for sale or supply, uses, applies, or transports any: (1) aggregate material extracted from property where any portion of the property is located in a geographic ultramafic rock unit; or (2) aggregate material extracted from property that is not located in a geographic ultramafic rock unit, if:

- The material has been evaluated at the request of the APCO and determined to be ultramafic rock or serpentine.
- Material tested at the request of the APCO is determined to have an asbestos content of 0.25% or greater or is determined by the owner/operator of a facility to be ultramafic rock or serpentine.
- The material has an asbestos content of 0.25% or greater.

The ATCM prohibits a person from using, applying, selling, supplying, or offering for sale or supply any restricted material for surfacing unless it has been tested and determined to have an asbestos content that is less than 0.25%.

Carbon Dioxide

Carbon dioxide, along with several other compounds, is considered a greenhouse gas (GHG) that is contributing to climate change. Discussion of carbon dioxide and other GHGs is included in Section 4.7, Greenhouse Gas Emissions and Global Climate Change of the 2015 Final Environmental Impact Report (FEIR; SREIR Volume 3).

Sensitive and Worker Receptors

Some land uses are considered more sensitive to air pollution than others due to the types of population groups or activities involved. Land uses that can be considered sensitive receptors include residential communities, schools, playgrounds, childcare centers, athletic facilities, long-term health care facilities, rehabilitation centers, convalescent centers, and retirement homes. Sensitive individuals with compromised immune systems, such as children and the elderly, may be exposed to emissions from the construction and operation of the Project. Worker receptors refer to employees and locations where people work. Impacts on sensitive receptors are of particular concern, because they are the people most vulnerable to the effects of air pollution.

Odorous Compounds

Odor refers to the perception or sensation experienced when one or more volatilized chemical compounds come in contact with receptors on the olfactory nerves. Odorant refers to any volatile chemical in the air that is part of the perception of odor by a human. The difference in sensory and physical responses experienced by individuals is responsible for the significant variability in the individual sensitivity to the quality and intensity of an odorant.

Several compounds associated with the oil and gas industry can produce odors that can be determined to be nuisances. Sulfur compounds, found in oil and gas, have very low odor threshold levels. For instance, H_2S can be detected by humans at concentrations from 0.5 parts per billion (ppb) (detected by 2% of the population), to 40 ppb, qualified as annoying by 50% of the population. These levels are significantly lower than concentrations that could affect human health (2 ppm [2,000 ppb] can cause headaches and increased airway resistance in asthmatics; inhalation of more than 600 ppm can be instantly lethal and inhalation of over 100 ppm can be lethal if exposed to for more than 60 minutes [ERPG-3]). ERPG-3 is the maximum airborne concentration below which nearly all individuals could be exposed for up to 1 hour without experiencing or developing life-threatening health effects.

Many volatile compounds found in oil and gas (ethane and longer chain hydrocarbons) typically have petroleum or gasoline odor with various odor thresholds.

Natural gas contains mostly methane (which is odorless), thus it has to be odorized as dictated by law, before being placed into a distribution pipeline. The various odorizing compounds that are used for odorization (e.g., methyl mercaptan or ethyl mercaptan), contain sulfur compounds having a very low odor threshold and can produce odors if released into the atmosphere.

Because most oil and gas production activities are located in rural areas, odors may accumulate with agricultural odorous compounds, which are typically produced by insecticides, chemical fertilizers, and compost, particularly manure. A large number of odorous compounds are released from agricultural and dairy activities, including notably ammonia (NH_3) and H_2S.

Baseline Emissions Inventory

Criteria Air Pollutants

Table 4.3-6 summarizes the CARB inventories for criteria air pollutant emissions from anthropogenic (i.e., not natural) sources in California, the SJV, and Kern County for 2012, defined by the applicant as the baseline year for the Project air quality impact analysis. These baseline data remain conservative and are adequate for purposes of this SREIR, as demonstrated by the SJVAPCD's emissions inventory issued in November 2018 for the 2018 Plan for the 1997, 2006, and 2012 $PM_{2.5}$ standards. As shown in Appendix B of the 2018 plan, emissions of $PM_{2.5}$, NO_X and other pollutants from oil and gas production declined from 2013 to 2017 and are forecasted to continue declining through 2028. (SJVAPCD 2018*a*)

Table 4.3-6: Criteria Air Pollutant Emissions Inventory – Year 2012

California Emissions Inventory (tons per day)						
Source Category	**NO_X**	**ROG**	**CO**	**SO_X**	**PM_{10}**	**$PM_{2.5}$**
Stationary Source	283.6	384.1	259.7	51.8	122.8	61.7
Areawide Source	75.1	608.8	970.7	6.1	1,213.0	271.0
On-road Mobile	1,024	403.5	3,937.6	5.38	77.6	43.1
Other Mobile	723.5	342.2	2,204.4	41.8	46.3	42.3
Total for State	2,106	1,739	7372	105	1,460	418
San Joaquin Valley Emissions Inventory (tons per day)						
Stationary Source	36.4	94.2	25.7	7.9	14.0	8.8
Areawide Source	13.3	176.2	186.8	1.3	250.2	54.0
On-road Mobile	177.9	48.5	437.7	0.7	10.8	6.7
Other Mobile	97.6	39.0	252.5	0.5	6.6	6.1
Total for SJV	325.2	357.9	902.6	10.4	281.6	75.6
Kern County Emissions Inventory (tons per day)						
Stationary Source	9.6	44.0	11.6	2.2	5.0	4.0
Areawide Source	1.5	21.8	9.0	0.03	35.0	6.5
On-road Mobile	48.6	9.4	81.9	0.2	2.7	1.8

Table 4.3-6: Criteria Air Pollutant Emissions Inventory – Year 2012

California Emissions Inventory (tons per day)						
Other Mobile	12.6	5.1	49.6	0.1	0.7	0.7
Total for Kern County	72.3	80.3	152.1	2.5	43.4	13.0

Source: Vector Environmental 2015.
Key:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SJV = San Joaquin Valley
SO_X = sulfur oxides

Toxic Air Contaminants

Table 4.3-7 summarizes California Toxics Inventory data in the SJVAB.

Table 4.3-7: San Joaquin Valley Toxic Emissions Inventory – 2010

	Emissions by Source Category (tons per year)[a]				
Pollutant	**Stationary Source**	**Area Source**	**Mobile Source**	**Other Sources**	**All Total**
Diesel Particulate	268.0	1.9	1,898.6	351.9	2,520.3
Formaldehyde	401.2	254.5	786.6	875.7	2,318.0
Benzene	239.4	11.8	456.4	313.6	1,021.2
Acetaldehyde	81.2	2,678.7	344.7	12,956.6	16,061.2
1,3-Butadiene	2.0	116.7	92.2	224.2	435.1
Perchloroethylene	305.0	143.0	0.0	0.0	448.0
Acrolein	6.1	80.8	32.2	34.0	153.0
Methylene Chloride	77.3	169.9	0.0	0.0	247.2
PAHs	40.1	19.3	88.1	90.7	238.2
p-Dichlorobenzene	4.7	125.7	0.0	0.0	130.3
Manganese	46.7	167.3	3.0	1.2	217.9
Styrene	26.2	25.6	23.5	10.5	95.8
Nickel	0.8	0.0	0.0	0.0	0.8
Chromium	4.1	27.9	2.2	0.2	34.4
Trichloroethylene	8.7	37.2	0.0	0.0	45.8
Lead	1.2	26.1	0.3	1.2	28.7
Vinyl Chloride	7.4	0.0	0.0	0.0	7.4
Acrylonitrile	7.3	0.0	0.0	0.0	7.3
Arsenic	1.9	2.9	0.03	0.4	5.2
Cadmium	0.4	2.9	0.04	0.1	3.4

Table 4.3-7: San Joaquin Valley Toxic Emissions Inventory – 2010

Pollutant	Emissions by Source Category (tons per year)[a]				
	Stationary Source	Area Source	Mobile Source	Other Sources	All Total
Mercury	0.2	2.1	0.01	0.01	2.2
Ethylene Oxide	0.2	0.0	0.0	0.0	0.2
Chloroform	1.8	0.0	0.0	0.0	1.8
Ethylene Dichloride	0.1	0.0	0.0	0.0	0.1
Beryllium	0.03	0.0	0.0	0.0	0.03
Carbon Tetrachloride	0.02	0.0	0.0	0.0	0.02
Dioxins/Benzofurans	0.0	0.0	0.0	0.0	0.0
Chromium-VI	0.2	0.0	0.0	0.01	0.2

Source: CARB 2013a.
Note:
[a] Emissions have been rounded up to the nearest decimal value.
Key:
PAH = polycyclic aromatic hydrocarbon

4.3.3 Regulatory Setting

Air quality in the Project Area is addressed through the efforts of various federal, state, regional, and local government agencies. The agencies primarily responsible for improving the air quality within the County include the EPA, CARB, SJVAPCD, and the Kern Council of Governments (COG). These agencies work jointly, as well as individually, to improve air quality through legislation, regulations, planning, policy-making, education, and a variety of programs. The agencies primarily responsible for improving the air quality within Kern County are discussed below, along with their individual responsibilities.

Federal

The principal air quality regulatory mechanism on the federal level is the CAA as amended in 1990 and, in particular, the NAAQS established by the EPA pursuant to the CAA. These standards identify levels of air quality for “criteria” pollutants that are considered the maximum levels of ambient (background) air considered safe, with an adequate margin of safety, to protect public health and welfare. The criteria pollutants include ozone, CO, NO_2, PM_{10}, $PM_{2.5}$, SO_2, which is a form of SO_X, and Pb. The EPA also has regulatory and enforcement jurisdiction over emission sources beyond state waters (outer continental shelf), and those that are under the exclusive authority of the federal government, such as aircraft, locomotives, and interstate trucking. The EPA’s primary role at the State level is to oversee the State air quality programs. The EPA sets federal vehicle and stationary source emission standards and oversees approval of all State Implementation Plans (SIPs), as well as providing research and guidance in air pollution programs. The SIP is a state-level document that identifies all air pollution control programs within California that are designed to help the State meet the NAAQS.

Attainment defines the status of a given airshed with regard to NAAQS requirements. Airsheds not meeting these standards are classified as "nonattainment."

Title V and Extreme Designation

Title V of the federal CAA, as amended in 1990, creates an operating permits program for facilities classified as major emission sources. Major emission sources are those that emit pollutants above the major source threshold applicable to the location of the emission source. In general, major source thresholds are 100 tons per year for any criteria pollutant. However, this will vary depending on the attainment status of the source's location. In an ozone extreme nonattainment area, such as the Project Area, sources that emit more than 10 tons per year of NO_X and ROG are classified as major sources for Title V permitting. This results in more businesses having to comply with Title V permitting requirements under the Extreme nonattainment designation.

Title V does not impose any new air pollution standards, require installation of any new controls on the affected facilities, or require reductions in emissions. Title V enhances public and EPA participation in the permitting process and requires additional recordkeeping and reporting by businesses, which results in significant administrative requirements.

EPA Emission Standards

The EPA establishes and maintains emission standards of performance of new stationary sources under CAA Section 111(b), as the New Source Performance Standards (NSPS; 40 CFR 60). Categories of existing stationary sources can also be retroactively controlled under CAA Section 111(d).

Categories of sources that cause HAP emissions are controlled through separate standards under CAA Section 112: NESHAP. These standards are specifically designed to reduce the potency, persistence, or potential bioaccumulation of toxic air pollutants. The emission standards for HAPs under CAA Section 112 prevent adverse health risks and carcinogenic effects from targeted types of facilities.

New Source Performance Standards (NSPS) for the Oil and Gas Sector

On May 12, 2016, the EPA issued three final rules that together will curb emissions of methane, smog-forming VOCs and toxic air pollutants such as benzene from new, reconstructed, and modified oil and gas sources. In this action, the EPA finalized standards based on the agency's determination of the best system of emissions reduction for reducing emissions of VOC across a variety of additional emission sources in the oil and natural gas source category (i.e., production, processing, transmission, and storage). These emission sources included hydraulically fractured oil well completions, pneumatic pumps, and fugitive emissions from well sites and compressor stations; hydraulically fractured gas well completions and equipment leaks at natural gas processing plants; and equipment that is used across the source category, for which the current NSPS at subpart OOOO regulates emissions of VOCs from only a subset (pneumatic controllers, centrifugal compressors, and reciprocating compressors), with the exception of compressors located at well sites (EPA 2016b, 2017).

The following Subparts of NSPS (40 CFR 60, Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources) are applicable to the Project:

- **NSPS Subpart OOOO:** Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015.
- **NSPS Subpart OOOOa**: Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015.
- **NSPS Subpart KKK:** Equipment Leaks of VOC from Onshore Natural Gas Processing Plants.
- **NSPS Subpart LLL:** SO_2 Emissions from Onshore Natural Gas Processing.
- **NSPS Subpart III:** Stationary Compression Ignition.
- **NSPS Subpart JJJ:** Spark Ignition Internal Combustion Engines.
- **NSPS Subpart KKKK:** Stationary Combustion Turbines.

National Emission Standards for Hazardous Air Pollutants (NESHAPs)

Emissions from various processes and operations at oil and natural gas facilities and natural gas transmission and storage facilities typically contain five different HAPs: benzene, toluene, ethyl benzene, mixed xylenes, and n-hexane. HAPs, also known as air toxics, are pollutants that are known or suspected to cause cancer or other serious health effects such as birth defects or reproductive effects (EPA 2016c).

The following subparts of NESHAP (40 CFR 61 and 63) are applicable to the Project:

- **NESHAP Subpart V (40 CFR 61):** Equipment Leaks and Fugitive Emissions.
- **NESHAP Subpart H (40 CFR 63):** Hazardous Organic Pollutant Equipment Leaks.
- **NESHAP Subpart HH (40 CFR 63):** Oil and Gas Natural Production.
- **NESHAP Subpart HHH (40 CFR 63):** Natural Gas Transmission and Storage.
- **NESHAP Subpart YYYY (40 CFR 63):** Stationary Combustion Turbines.
- **NESHAP Subpart ZZZZ (40 CFR 63):** Reciprocating Internal Combustion Engines**.**

EPA Natural Gas STAR Program

Established in 1993, this voluntary program encourages oil and natural gas companies to adopt cost-effective technologies and practices to improve operational efficiency and prevent methane emissions. The Natural Gas STAR program defines protocols for methane control at natural gas production facilities, resulting in concomitant reductions of other organic compounds (EPA 2015a).

Cumulatively, Gas STAR Partners have reduced nearly 1.39 trillion cubic feet of methane emissions since the program began (EPA 2018).

As of January 14, 2015, the EPA announced an additional strategy for a series of steps it plans to take to address methane and smog-forming VOC emissions from the oil and gas industry (EPA 2015b). The steps include building on commonsense standards for VOC emissions to help avoid anticipated increase in methane emissions from new sources; reducing additional pollution in areas with ozone problems by issuing control techniques guidelines that provide an analysis of the available, cost-effective technologies for controlling VOC emissions from covered oil and gas sources; and providing additional support for industry actions to reduce methane emissions.

State

California Air Resources Board

The CARB, a department of the California Environmental Protection Agency, oversees air quality planning and control throughout California by administering the SIP. Its primary responsibility lies in ensuring implementation of the 1989 California Clean Air Act (CCAA), responding to the federal CAA requirements, and regulating emissions from motor vehicles sold in California. It also sets fuel specifications to further reduce vehicular emissions.

The CCAA establishes a legal mandate to achieve many of the CAAQS by the earliest practical date. These standards apply to the same criteria pollutants as the federal CAA, and also include sulfate, visibility reducing particulates, H_2S, and vinyl chloride. They are also more stringent than the federal standards.

CARB is also responsible for regulations pertaining to TACs. The “Tanner Act,” enacted in 1983, directed CARB to identify TACs and to adopt ATCMs to “reduce, avoid, or eliminate the emissions of a toxic air contaminant.” To date, CARB has formally identified 21 TACs and has adopted 26 ATCMs (CARB 2015). The Air Toxics “Hot Spots” Information and Assessment Act (Assembly Bill [AB] 2588; Health & Safety Code §§ 44300 et seq.) was enacted in 1987 as a means to establish a formal air toxics emission inventory risk quantification program. AB 2588, as amended, establishes a process that requires stationary sources to report the type and quantities of certain substances their facilities routinely release into their air basin. Each air pollution control district ranks the data into high, intermediate, and low priority categories. When considering the ranking, the potency, toxicity, quantity, volume, and proximity of the facility to receptors are given consideration by an air district. AB 2588 was amended in 1992 by Senate Bill (SB) 1731, and further modified by AB 564 in 1996. The goal of the Air Toxics “Hot Spots” Act, as amended, is to collect emission data indicative of routine predictable releases of toxic substances to the air, to identify facilities having localized impacts, to evaluate health risks from exposure to the emissions, to notify nearby residents of significant risks, and, reduce risk below the determined level of significance (CARB 2014a).

CARB also has on-road and off-road engine emission reduction programs that indirectly affect the Project’s emissions through the phasing in of cleaner on-road and off-road equipment engines. Additionally, CARB has a Portable Equipment Registration Program that allows owners or operators of portable engines and associated equipment to register their units under a statewide portable program to operate their equipment that must meet specified program emission requirements throughout California without having to obtain individual permits from local air districts.

The State has also enacted an ATCM for the reduction of DPM and criteria pollutant emissions from in-use off-road diesel-fueled vehicles (CCR Title 13, Article 4.8, Chapter 9, Section 2449). This regulation provides target emission rates for PM and NO_X emissions from owners of fleets of diesel-fueled off-road vehicles and applies to equipment fleets of three specific sizes and the target emission rates are reduced over time (CARB 2007).

Regulation of Air Pollution Transport between Air Basins

The CCAA directs CARB to assess the contribution of ozone and ozone precursors in upwind basins or regions to ozone concentrations that violate the state ozone standard in downwind basins or regions. The movement of ozone and ozone precursors between basins or regions is referred to as “transport.” In addition, the CCAA directs CARB to establish mitigation requirements for upwind districts commensurate with their contributions to the air quality problems in downwind basins or regions.

Over the last decade, CARB has published several transport reports that include technical assessments of transport relationships between air basins and regions in California. Along with these technical assessments, the reports have included mitigation requirements to ensure that upwind areas do their part to limit the effects of transport on their downwind neighbors. CARB originally established mitigation requirements in 1990, which are contained in Title 17, CCR, Sections 70600 and 70601. These regulations were amended in 1993 and more recently in 2003. The 2003 amendments added two new requirements for upwind districts. These amendments require upwind districts to: (1) consult with their downwind neighbors and adopt “all feasible measures” for ozone precursors; and (2) amend their “no net increase” thresholds for permitting so that they are equivalent to those of their downwind neighbors. The amendments clarify that upwind districts are required to comply with the mitigation requirements, even if they attain the state ozone standard in their own district, unless the mitigation measures are not needed in the downwind district.

According to SJVAPCD, air pollution transported from the San Francisco Bay and Sacramento areas account for approximately 27% of the total emissions in the northern portion of the SJVAPCD (San Joaquin, Stanislaus, and Merced counties). In the Central region (Fresno, Madera, and Kings counties), the percentage drops to 11%, and in the south valley (the valley portion of Kern and Tulare counties), transported air pollution accounts for only 7% of the total problem.

The Mojave Desert Air Basin (MDAB) includes the desert portions of Los Angeles, Kern, San Bernardino, and Riverside counties. Most of this area is commonly referred to as the “high desert,” because elevations range from approximately 2,000 to 5,000 feet above sea level. The MDAB is characterized by extreme temperature fluctuations, strong seasonal winds, and clear skies. While the Project limits do not extend into the Kern County portion of the MDAB, studies in the southern

SJV, South Coast Air Basin (SCAB), and other airsheds have included intensive ozone and meteorological measurements, tracer studies, and development of transport models (CARB 2009). The issue of ozone transport in the Kern County area has been studied for over 30 years. A study by Sonoma Technology (2006) recognized the significant ozone transport from the SJV into the Mojave Desert area through the Tehachapi Pass.

The topography and climate of southern California combine to make the SCAB an area with a high potential for air pollution, which constrains efforts to achieve clean air. During the summer months, a warm air mass frequently descends over the cool, moist marine layer produced by the interaction between the ocean’s surface and the lowest layer of the atmosphere. The warm upper layer forms a cap over the cool marine layer and inhibits the pollutants in the marine layer from dispersing upward. In addition, light winds during the summer further limit ventilation. Furthermore, sunlight triggers the photochemical reactions which produce ozone, and this region experiences more days of sunlight than many other major urban areas in the nation (South Coast Air Quality Management District 2006). Transboundary ozone transport form Asia and its impact on air quality in the SJVAB is being further studied and increases in ozone levels due to transport have been confirmed (SJVAPCD 2013b).

Assembly Bill 617

AB 617 (August 2017) directs CARB and all local air districts to take measures to protect communities disproportionately impacts by air pollution. The primary components of AB 617 include (1) community-level air monitoring; (2) a state strategy and community-specific emission reduction plans; (3) accelerated review of retrofit pollution control technologies on industrial facilities subject to Cap-and-Trade; (4) enhanced emission report requirements; and (5) increased penalty for polluter violations. Additional, CARB may direct additional grant funding to communities determined to have the highest air pollution burdens.

In response to AB 617, CARB established the Community Air Protection Program. The Community Air Protection Program’s focus is to reduce exposure in communities most impacted by air pollution. CARB staff has already begun working closely with local air districts, community groups, community members, environmental organizations, and regulated industries to develop a new community-focused action framework for community protection.

Local

San Joaquin Valley Air Pollution Control District

State law assigns much of the authority to regulate stationary, indirect, and area sources to local air pollution control and air quality management districts. The SJVAPCD has primary responsibility for regulating stationary sources of air pollution situated within its jurisdictional boundaries. To this end, the SJVAPCD implements air quality programs required by State and federal mandates, enforces rules and regulations based on air pollution laws, and educates businesses and residents about their role in protecting air quality. The SJVAPCD is responsible for regulating stationary, indirect, and area sources of air pollution in the SJVAB. The eight counties that comprise the SJVAPCD are divided into three regions: the Northern Region (Merced, San Joaquin, and

Stanislaus counties), Central Region (Madera, Fresno, and Kings counties), and Southern Region (Tulare County and SJV portion of Kern County).

The SJV (or portions thereof) is designated as nonattainment with respect to federal air quality standards for ozone and $PM_{2.5}$. The SJV has a maintenance plan for PM_{10} and for CO for the urbanized/metropolitan areas of Kern, Fresno, Stanislaus, and San Joaquin counties.

The SJVAPCD is responsible for managing and permitting existing, new, and modified sources of air emissions within its boundaries and also established the following rules and regulations to ensure compliance with local, State, and federal air quality regulations:

Rules and Regulations

The following SJVAPCD Rules and Regulations apply to the oil and gas production industry and its ancillary facilities.

Regulation I (General Provisions)

Regulation I (General Provisions) is a series of rules that establish the basic framework for interacting with the SJVAPCD including enforcement procedures, inspections, and source sampling requirements, and regulatory accountability.

Regulation II (Permits)

Rule 2010 (Permits Required) requires any person constructing, altering, replacing, or operating any source operation which emits, may emit, or may reduce emissions to obtain an Authority to Construct (ATC) or a Permit to Operate (PTO).

Rule 2092 (Standards for Permits to Operate) defines the conditions that must be met for an APCO to issue a PTO.

Rule 2201 (New and Modified Stationary Source Review Rule) provides for the review of new and modified Stationary Sources of air pollution and to provide mechanisms including emission offsets by which Authorities to Construct such sources may be granted, without interfering with the attainment or maintenance of Ambient Air Quality Standards; and ensure that no net increase in emissions above specified thresholds from new and modified Stationary Sources of all nonattainment pollutants and their precursors occur.

Rule 2250 (Permit-Exempt Equipment Registration) is essentially an SJVAPCD rule designed to provide the SJVAPCD with oversight of equipment that would otherwise not require an air permit. According to the SJVAPCD's Permit-Exempt Equipment Registration (PEER) – Frequently Asked Questions document, "PEER is necessary to enforce the requirements of certain District prohibitory rules in which the emissions equipment is exempt from permitting requirements" (SJVAPCD 2008). Section 4.5 of Rule 2250 states that the District shall issue the PEER within 90 days of receipt of a completed application. Sections 4.7 and 4.8 of the rule specify that a PEER unit is neither transferable between locations or owners without an application for transfer. See Rule 3155 for information on fees relating to PEER units. Additionally, Rules 4702, 4307, and 4622 define different types of PEER units.

Rule 2260 (Registration Requirements for Equipment Subject to California's Oil and Gas Regulation) is applicable to owners or operators of equipment subject to California's Oil and Gas Regulation (Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, 17 CCR § 95665 et seq.) and provides a registration mechanism that satisfies compliance requirements. As defined in 17 CCR § 95667 (a)(19), this rule applies to any building, structure, or installation to which California's Oil and Gas Regulation applies and which has the potential to emit natural gas. By March 1, 2018, and to the extent required by CARB, the owner or operator of facilities or equipment regulated by California's Oil and Gas Regulation shall submit CARB data inventory information for each facility to the district.

Rule 2280 (Portable Equipment Registration) provides the administrative requirements for permitting portable emissions units for operation in participating districts throughout the state of California, starting in Sections 4.0 to 4.13 of the rule. To register portable equipment, an application must be submitted to the district in which operation will first occur. The Applicant shall provide the administering district with all necessary emissions and engineering data to demonstrate compliance with Section 5 of this rule. Section 4.4 states that prior to issuing a permit for portable registration, the SJVAPCD will conduct an onsite inspection of the unit. There are several notification and reporting rules associated with portable equipment. Namely, Section 6.1 states that if a portable emissions unit remains at a location for more than 24 hours, the SJVAPCD must be notified within two calendar days, and Section 6.2 states that within 30 days after the end of every calendar quarter, the SJVAPCD must be provided with the level of activity (hours of operation) for the previous quarter, unless the equipment is a rental. Finally, Section 8.0 provides emissions limitation (the total NO_X, or VOCs emissions from a project shall not exceed 100 pounds during any one day, for each pollutant, and the total PM_{10} emissions from a project shall not exceed 150 pounds during any one day) and minimum distance requirements of 1,000 feet from kindergarten to 12th grade schools. The actual emissions from the unit, when operated as a registered portable emissions unit, as verified by recordkeeping as prescribed by this rule, shall not exceed 10 tons per year of any affected pollutant when operated in any participating district.

Rule 2410 (Prevention of Signification Deterioration) - Rule 2410 is triggered when obtaining construction permits for a new major stationary source and/or major modification to existing major stationary sources located in areas classified as "in attainment" or in areas that are unclassifiable for any criteria pollutant. The most important of the "Requirements" in Section 4.0 of Rule 2410 is that of Subsection 4.1 requiring that a Prevention of Significant Deterioration (PSD) permit be obtained prior to beginning any construction of a new major stationary source or a major modification to an existing major stationary source. Lastly, the SJVAPCD must follow the public notice requirements of Rule 2201 prior to issuing a federal PSD permit.

Rule 2520 (Federally Mandated Operating Permits) provides an administrative mechanism for issuing operating permits for new and modified sources of air contaminants in accordance with requirements of 40 CFR Part 70 (State Operating Permit Programs). Amended on August 15, 2019, this rule applies to major sources of air toxics, stationary sources with the potential to emit

100 tons per year or more of any air contaminant, a source that EPA determines is required to obtain a Part 70 permit upon promulgation of a standard issued pursuant to Section 111 or 112 of the CAA, sources required by the PSD program to have a preconstruction review, solid waste incinerators subject to Sections 111 or 129 of the CAA, and any source in a source category designated by the EPA pursuant to 40 CFR Part 70.3.

Rule 2540 (Acid Rain Program) incorporates the Acid Rain Standards from Part 72, Title 40 CFR and is applicable to all stationary sources subject to Part 72, Title 40, CFR.

Rule 2550 (Federally Mandated Preconstruction Review for Major Sources of Air Toxics) applies to applications to construct or reconstruct a major air toxics source with an ATC issued on or after June 28, 1998. Section 5.0 of Rule 2550 requires the application of toxic best available control technology to new major air toxic sources and sources with the potential to emit in excess of a major air toxic source threshold. Section 6.1 requires an application for ATC for major air toxic sources subject to the requirements of SJVAPCD Rule 2201.

Regulation III (Fees)

Regulation III sets the fees associated with owning and operating facilities, activities, and equipment that have the potential to emit air pollutants in the SJV. This rule was last amended on July 1, 2019.

Regulation IV (Prohibitions)

Rule 4001 (New Source Performance Standards) applies to all new sources of air pollution and modifications of existing sources of air pollution within the source categories for which EPA has adopted standards. Section 4.0, Requirements, of Rule 4001 lists all of the provisions of 40 CFR Part 60 that are incorporated into the NSPS.

Rule 4002 (National Emission Standards for Hazardous Air Pollutants). In the event that any portion of an existing building will be renovated, partially demolished, or removed, the Project will be subject to SJVAPCD Rule 4002. Prior to any demolition activity, an asbestos survey of existing structures on the Project site may be required to identify the presence of any asbestos-containing building material (ACBM). Any identified ACBM having the potential for disturbance must be removed by a certified asbestos contractor in accordance with California Occupational Safety and Health Administration (Cal/OSHA) requirements.

Rule 4101 (Visible Emissions) prohibits the emission of visible air contaminants into the atmosphere and applies to any source operation with the potential to emit air contaminants. Sections 4.0 to 4.12 list the following exemptions: fires set by a permitted public officer (such as those for the instruction of fighting fire), orchard or citrus grove heater that produces less than one gram per minute unconsumed solid carbonaceous matter, hazard reduction burning, aircraft distribution of agricultural aids over lands devoted to agriculture, open outdoor fires used for cooking and/or recreation, emissions from equipment used for the instruction/certification of individuals in visible emissions, wet plumes where the presence of uncombined water is the only reason for the failure of an emission to meet rule limitations, emissions from maritime vessels using steam boilers during emergency boiler shutdowns for safety reasons, the use of an obscurant for the purpose of training military personnel and the testing of military equipment by the U.S. Department of Defense, and emissions specifically exempt from Regulation VIII. Sections 5.0 to 5.2 require that there be no discharge from a single source of emission for a period or periods aggregating more than 3 minutes in any one hour that is as dark or darker than a designated Ringelmann No. 1 rating by the U.S. Bureau of Mines, or of opacity that can obscure an observers view equal to or greater than the Ringelmann No. 1 rating.

Rule 4102 (Nuisance) applies to any source operation that emits or may emit air contaminants or other materials. In the event that the Project or construction of the Project creates a public nuisance, it could be in violation and be subject to SJVAPCD enforcement action.

Rule 4201 (Particulate Matter Concentration) sets a standard maximum of 0.1 grain per cubic foot of gas at dry standard conditions for PM emissions. This rule applies to any source operation that emits dust, fumes, or total suspended PM.

Rule 4202 (Particulate Matter – Emission Rate) establishes allowable emissions rates for PM. This rule requires any source operation that may emit PM emissions to meet the standards set forth in the table "Allowable Emission Rate Base on Process Weight Rate."

Rule 4301 (Fuel Burning Equipment) was created to limit the emission of air contaminants from fuel burning equipment. This rule applies to any fuel burning equipment except air pollution control equipment which is exempted in Section 4.0 of this rule. This rule requires in Section 5.0 that combustion contaminants discharged into the atmosphere do not exceed 0.1 grain per cubic foot of gas calculated to 12% CO_2 at dry standard conditions. The rule also requires building, installing, and expanding non-mobile fuel burning equipment not to exceed 200 pounds/hour of sulfur compounds, 140 pounds/hour of N_2O, or 10 pounds/hour of combustion contaminants as defined in rule 1020 (definitions) and derived from the fuel. Finally, Section 6.0 specifies the test methods that can be used to determine compliance.

Rule 4304 (Equipment Tuning Procedures for Boilers, Steam Generators, and Process Heaters) applies to any boiler, steam generator, or process heater that requires tuning pursuant to SJVAPCD regulations or permit conditions. Attachments to this rule detail tuning requirements for different types of boilers, steam generators, and process heaters: Mechanical Draft (4304-A) and Natural and Induced Draft (4304-B).

Rule 4305 (Boilers, Steam Generators, and Process Heaters – Phase 2) limits the emissions of NO_X and CO emissions from boilers, steam generators, and process heaters. This rule applies to any gaseous fuel or liquid fuel fired boiler, steam generator, or process heater with a heat input rating greater than 5 million metric British thermal units per hour (MMBtu/hr). Exemptions to the rule are solid fuel fired units, dryers, kilns and smelters, unfired or fired waste recovery boilers that are used to recover or augment heat from the exhaust of combustion turbines or internal combustion engines, and exemptions from the requirements when using fuel other than Public Utilities Commission quality natural gas during curtailments and for units that operate exclusively from November to February for less than 500 hours total. Amongst the requirements in Section 5.0 of this rule, the most commonly referenced is the NO_X emission limits table in Section 5.1.1, setting the following limitations: For all units, except box or cabin type units and vertical cylindrical process heaters operated on gaseous fuel 30 parts per million volume (ppmv) or 0.036 pounds per million metric British thermal unit (lb/MMBtu) or operated on liquid fuel 40 ppmv or 0.052 lb/MMBtu. For box or cabin type units, and vertical cylindrical process heaters operated on gaseous fuel, 147 ppmv or 0.18 lb/MMBtu or operated on liquid fuel, 155 ppmv or 0.2 lb/MMBtu. Units operated on a combination of gaseous and liquid fuel shall use a heat input weighted average of the previous limits. Additionally, all units subject to this rule shall not exceed 400 ppmv of CO emissions.

Rule 4306 (Boilers, Steam Generators, and Process Heaters – Phase 3) limits emissions of NO_X and CO from boilers, steam generators, and process heaters and "build on" the rules set forth in Rule 4305. As with Rule 4305, this rule applies to any gaseous fuel or liquid-fired boiler, steam generator, or process heater with a total rated heat input greater than 5 MMBtu. Section 5.0 of this rule sets forth extensive NO_X and CO limits, in addition to monitoring provisions in Sections 5.4 to 5.4.5. Additionally, there are compliance testing guidelines in Section 6, most often requiring a source test to demonstrate compliance annually.

Rule 4307 (Boilers, Steam Generators, and Process Heaters 2.0 MMBtu/hr to 5.0 MMBtu/hr) limits the emissions of NO_X, CO, SO_2, and PM_{10} from gaseous or liquid fuel fired boilers, steam generators or process heaters with a total rated heat input of 2.0 MMBtu /hr up to and including 5.0 MMBtu/hr. NO_X and CO limits are set forth in Sections 5.0 to 5.6.5 of this rule in which details on PM_{10} control requirements, start up and shut down requirements, monitoring provisions and more are provided.

Rule 4308 (Boilers, Steam Generators, and Process Heaters 0.075 MMBtu/hr to less than 2.0 MMBtu/hr) limits NO_X and CO from boilers, steam generators, process heaters, and water heaters with heat inputs greater than or equal to 0.075 MMBtu/hr to less than 2.0 MMBtu/hr. Exemptions from this rule are units installed in manufactured homes, recreational vehicles, and hot water pressure washers. Tables 1 and 2 in Section 5.0 of this rule provide emissions limits while administrative requirements, such as source testing and certification for retrofits, are provided in Section 6.0.

Rule 4311 (Flares) limits VOC, NO_X, and SO_X from the operation of flares. Exempted flares are those operated in municipal solid waste landfills subject to the requirements of Rule 4642, flares subject to the requirements of 40 CFR Subpart WWWW or Cc, and stationary sources with the potential to emit less than 10 tons per year of VOC and NO_X (recordkeeping requirements do apply for stationary sources however). Section 5.0 of this rule sets forth requirements such as automatic ignition systems and flow-sensing ignition systems in given circumstances, as well as provides emission standards for VOC and NO_X from ground-level enclosed flares. Note that Section 5.9 specifically addresses petroleum refinery SO_2 performance targets requiring the minimization of SO_2 flare emissions to less than 1.50 tons per million barrels of crude processing capacity and on and after January 1, 2017, this limit drops to 0.50 tons per million barrels of crude processing capacity, calculated as an average over one calendar year. Administrative requirements in Section 6.0 primarily require compliance demonstration, flare reporting, annual monitoring, flare minimization plans for petroleum refinery flares with a capacity greater than or equal to 5.0 MMBtu/hr, vent gas composition monitoring, pilot purge gas monitoring, water seal monitoring, video monitoring, and general monitoring.

Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr) limits NO_X, CO, SO_2, and PM_{10} emissions from boilers, steam generators, and process heaters with a total heat input greater than 5 MMBtu/hr. Section 4.0 of this rule provides several exemptions such as solid fuel fired units, dryers and glass melting furnaces, kilns and smelters where the products of combustion come into direct contact with the material to be heated, and unfired or fired heat recovery boilers that are used to recover or augment heat from the exhaust of combustion turbines or internal combustion engines. The requirements in Section 5.0 detail compliance deadlines, emissions limits, annual fees, PM requirements, startup and shutdown requirements, monitoring provisions, and compliance determination. Under Section 6.0 (Administrative Requirements) are details on compliance testing and emissions control plans.

Rule 4351 (Boilers, Steam Generators, and Process Heaters – Phase 1) limits NO_X emissions from boilers, steam generators, and process heaters to levels consistent with reasonably available control technology. This rule applies to a boiler, steam generator, or process heater with a rated heat input greater than 5 MMBtu/hr that is fired with gaseous and/or liquid fuels and is included in a major NO_X source. (Note: This rule does not apply to any unit located west of Interstate Highway 5 located in Fresno, Kern or Kings counties.) Section 5.1 of this rule details NO_X emission limits for any unit with a heat input equal to or greater than 9 billion British thermal units (Btu) per year, as well as NO_X compliance alternatives and compliance schedules.

Rule 4352 (Solid Fuel-Fired Boilers, Steam Generators, and Process Heaters) limits the emissions of NO_X and CO from any solid fuel fired boiler, steam generator, and/or process heater. Section 4.0, Exemptions, of this rule states that except for complying with recordkeeping requirements, this rule does not apply to any stationary source with a potential to emit less than 10 tons per year of NO_X or VOC. Emissions limits are provided in Table 1 of Section 5.0.

Rule 4401 (Steam Enhanced Crude Oil Production Wells) limits VOC emissions from steam-enhanced crude oil production wells and applies to any steam-enhanced cruel oil production well and any associated VOC collection and control system. Section 4.0 of this rule lists seven exemptions given certain circumstances. Section 5.0, Requirements, lists well venting requirements, determination of compliance with the Leak Standards, operating, inspection and re-inspection, and leak repair requirements. Additionally, the Administrative Requirements of Section 6.0 requires that all operators maintain records for five years with further detail on the record required. This section also required annual Compliance Source Testing, test methods, an inspection log, employee training, and operator management plan.

Rule 4402 (Crude Oil Production Sumps) limits VOC emissions from sumps and applies to all first, second, and third stage sumps at facilities producing, gathering, separating, processing, and/or storing crude oil in an oilfield. This rule prohibits first stage sumps as of January 1, 2013, and requires a flexible floating cover or rigid floating cover equipped with closure device between the sump wall and the cover edge for all second and third stage sumps. Section 6.0 of this rule also contains administrative requirements.

Rule 4404 (Heavy Oil Test Station – Kern County) limits VOC emissions from the operation of heavy oil test stations by imposing emissions control requirements.

Rule 4405 (Oxides of Nitrogen Emissions from Existing Steam Generators used in Thermally Enhanced Oil Recovery – Central and Western Kern County Fields) limits NO_X emissions from oil field steam generators by setting forth NO_X emissions limits and alternate emission limits in Section 4.0 and 5.0 of this rule. This rule applies to existing steam generators used in thermally enhanced oil recovery in the Central and Western Kern County Fields.

Rule 4406 (Sulfur Compounds from Oilfield Steam Generators – Kern County) limits the emissions of sulfur from oilfield operations in Kern County but does not apply to cogeneration facilities. After July 1, 1984, emissions are limited to 0.11 pounds of sulfur per MMBtu of heat input. In addition to exempting cogeneration, this rule has a small producer exemption in Section 8.0 of this rule.

Rule 4407 (In-Situ Combustion Well Vents) implements federally enforceable emission limits for in situ combustion well vents and applies to crude oil production where production has been enhanced by in situ combustion. The rule requires that no person operate an in situ combustion well unless the vent is connected to an emissions control device that abates 85% by weight of entering VOC gases and vapor or fuel burning equipment or a smokeless flare. All components of a collection and control system shall be maintained in good repair and the total number of leaks in a collection and control system shall not exceed 2% of the components in that system.

Rule 4408 (Glycol Dehydration Systems) limits VOC emissions from any glycol dehydration system with a glycol dehydration vent that is subject to permitting requirements pursuant to Regulation II (Permits). The requirements of this rule do not apply if a glycol dehydration system is permitted to operate less than 200 hours per year, or is permitted to dehydrate less than 5 million standard cubic feet of gas per year. This rule requires controlling vents using a system that directs all vapors to a vapor recovery system, a fuel gas system or a sales gas system, or a system in which VOC emissions are combusted by a flare, incinerator, reboiler, or thermal oxidizer or any other emissions control system that controls glycol dehydration emissions by at least 95%. There are several administrative requirements in Section 6.0 of this rule worth noting, loosely: glycol dehydration vent testing, vent emission testing, emission control system testing, and the utilization of the gas research institute's GLYCalc™ software.

Rule 4409 (Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities) limits VOC emissions from leaking components at light crude oil production facilities, natural gas production facilities, and natural gas processing facilities. This rule applies to components containing or contacting VOC streams at the above-mentioned facilities. Section 3.0 of this rule has a number of definitions, while Section 4.0 details exemptions. This rule provides operating requirements, details, SJVAPCD inspections, leak standards, repair periods, component control technology replacement/retrofit, and component identification requirements.

Rule 4601 (Architectural Coatings) limits VOCs from architectural coatings. This rule specifies architectural coatings storage, clean up, and labeling requirements and is applicable to any person who supplies, sells, offers for sale, applies, or solicits the application of any architectural coating or who manufactures, blends, or repackages any architectural coating for use within the SJVAPCD. Aerosol coating products, architectural coatings from outside of the SJVAPCD, and the majority of architectural coating containers with a volume of one liter or less are exempt. VOC contents, restrictions, directions for thinning, and a table of standards are all supplied in the requirements in Section 5.0.

Rule 4623 (Storage of Organic Liquids) limits VOC emissions from the storage of organic liquids. This rule applies to any tank with a capacity of 1,100 gallons or greater in which any organic liquid is placed, held, or stored. Table 1 provides General VOC Control System Requirements and Table 2 provides Small Producer VOC Control System Requirements for Crude Oil Storage Tanks. This rule provides specification for pressure-vacuum relief valves and external floating roof tanks in Section 5.2 and 5.3, as well as guidance for welded tanks with primary metallic-shoe type seals, tanks with primary resilient toroid seals and much more guidance based on seal type in the latter portion of Section 5.0. Additionally, Section 5.6 provides specification for vapor recovery systems and Section 5.7.5.4 provides tank degassing requirements. There are many administrative requirements ranging from inspections to gravity testing to recordkeeping in Section 6.0.

Rule 4624 (Transfer of Organic Liquid) limits VOC emissions from the transfer of organic liquids and applies to organic liquid transfer facilities as defined within the rule. This rule requires that VOC emissions from Class 1 organic liquid transfer facilities not exceed 0.08 pounds per 1,000 gallons of liquid transferred. Additionally, Class 2 organic liquid transfer facilities shall prevent the release to the atmosphere of at least 95% by weight of the VOC displaced during organic liquid transfers. Section 5.0 of this rule also sets forth delivery, transfer, construction and leak inspection requirements. Several recordkeeping requirements are detailed in Section 6.0 in addition to compliance testing.

Rule 4625 (Wastewater Separators) limits the emission of VOCs from wastewater separators, including air floatation units as defined in this rule, during the separation of crude oil and water after custody transfer by requiring vapor loss control devices, recordkeeping, inspection, and test methods.

Rule 4641 (Cutback, Slow Cure, and Emulsified Asphalt, Paving, and Maintenance Operations) limits VOC emissions by restricting the application and manufacturing of certain types of asphalt for paving and maintenance operations. This rule applies to the manufacture and use of cutback asphalt, slow cure asphalt and emulsified asphalt for paving and maintenance operations. Section 5.0 of this rule requires that a person shall not manufacture for sale nor use any of the following for penetrating prime coat, tack coat, dust palliative, or other paving and maintenance operations: rapid cure cutback asphalt, medium cure cutback asphalt, slow cure asphalt which contains more than 0.5% of organic compounds, which evaporate at 500 degrees

Fahrenheit or lower, or emulsified asphalt containing organic compounds in excess of 3% by volume which evaporate at 500°F or lower.

Rule 4642 (Solid Waste Disposal Sites). The purpose of this rule is to reduce VOC emissions from any solid waste disposal site that has a gas collection system and/or control device in operation, or that is undergoing maintenance or repair. In addition to several exemptions, this rule provides regulatory guidance on gas collection systems at solid waste disposal sites, control devices, emission controls during excavation of solid waste, and emission control during maintenance.

Rule 4651 (Soil Decontamination Operations) limits the emissions of VOCs from soil that has been contaminated with a VOC-containing liquid and applies to operations involving the excavation, transportation, handling, decontamination, and disposal of contaminated soil. Exempt from this rule is the excavation, handling, transportation, and decontamination of less than 1 cubic yard of contaminated soil per occurrence, operations related to the accidental spillage of 5 gallons or less of VOC-containing liquid per occurrence, contaminated soil exposed for the sole purpose of sampling, and soil contaminated solely by a known VOC-containing liquid or petroleum liquid that has an initial boiling point of 320°F. Rule requirements in Section 5.0 of this rule span written notices, monitoring, handling, storage, transportation, and decontamination.

Rule 4661 (Organic Solvents) limits the emission of VOCs from the use of organic solvents while specifying reduction, monitoring, reporting, and disposal requirements. This rule applies to any source operation that uses organic solvents unless the source operation is exempted under Section 4.0.

Rule 4662 (Organic Solvent Degreasing Operations). The purpose of this rule is to limit VOCs and hazardous air pollutant emissions from organic solvent degreasing operations and to provide the administrative requirements for recording and measuring emissions. This rule applies to all organic solvent degreasing operations. Section 4.0 sets forth exemptions to the rule. Section 5.0 details the rule's requirements such as cold cleaner requirements, cold cleaner VOC emission control system requirements, general operating requirements for degreasers that are not cold cleaners, open-top vapor degreaser requirements, and conveyorized degreasers that are not cold cleaner. Also important are the recordkeeping requirements of Section 6.1 such as waste disposal records and VOC emission control system records.

Rule 4663 (Organic Solvent Cleaning, Storage and Disposal) limits the emission of VOCs from organic solvent cleaning and from the storage and disposal of solvents and waste solvent materials. This rule is applicable to any organic solvent cleaning performed outside a degreaser during the production, repair, maintenance, or services of parts, products, tools, machinery, equipment, or in general work areas at stationary sources. This rule also applies to the storage and disposal of all solvents and waste solvent materials at stationary sources.

Rule 4701 (Internal Combustion Engines – Phase 1) limits the emission of NO_X, CO, and VOCs from internal combustion engines. The rule applies to any internal combustion engine rated greater than 50 brake horsepower that requires a PTO except for those exempted in Section 4.0.

Rule 4702 (Internal Combustion Engines) limits the emissions of NO_X CO, VOC and SO_X from internal combustion engines. The rule applies to any internal combustion engine rate at 25 brake horsepower or greater.

Rule 4703 (Stationary Gas Turbines) limits NO_X emissions from stationary gas turbine systems and applies to all stationary gas turbine systems that are subject to district permitting requirements and with ratings equal to or greater than 0.3 megawatt or a maximum heat input rating of more than 3,000,000 Btu per hour, except as provided in Section 4.0 of this rule.

Rule 4801 (Sulfur Compounds) limits the emissions of sulfur compounds. This rule applies to any discharge to the atmosphere of sulfur compounds that exist as a liquid or a gas at standard conditions. This rule has no exemptions and requires that a person shall not discharge sulfur compounds in concentrations exceeding 0.2% by volume calculated as SO_2 on a dry basis averaged over 15 consecutive minutes. Additionally, EPA Method 8 and CARB method 1-100 must be used to determine such emissions.

Regulation V (Procedure Before the Hearing Board)

Regulation V (Procedure Before the Hearing Board) establishes the procedures in which an owner/operator can approach the Hearing Board to file petitions for variances from regulations.

Regulation VI (Air Pollution Emergency Contingency Plan)

Regulation VI (Air Pollution Emergency Contingency Plan) establishes a plan of action to be taken to prevent air pollutant concentration from reaching levels that could endanger the public health or to abate such concentrations should they occur.

Regulation VII (Toxic Air Pollutants)

Rule 7050 (Asbestos - Containing Material for Surfacing Applications). The purpose of this rule is to control airborne emissions of asbestos-containing rock. Compliance schedule, recordkeeping, and test methods are specified. This rule incorporates provisions of the CCR Section 93106.

Regulation VIII (Fugitive PM_{10} Prohibitions)

Regulation VIII (Fugitive PM_{10} Prohibitions) is a series of rules to reduce ambient concentrations of PM_{10} by requiring actions to prevent, reduce, or mitigate anthropogenic fugitive dust emissions.

Rule 8021 (Construction, Demolition Excavation, Extraction, and Other Earthmoving Activities) limits fugitive dust emissions from construction, demolition, excavation, extraction, and other earthmoving activities and applies to any construction, demolition, excavation, extraction, and other earthmoving activities, including, but not limited to, land clearing, grubbing, scraping, travel onsite, and travel on access roads to and from the site.

Rule 8031 (Bulk Materials) limits fugitive dust emissions from the outdoor handling, storage, and transport of bulk materials and applies to the outdoor handling, storage, and transport of any bulk material.

Rule 8041 (Carryout and Trackout) prevents or limits fugitive dust emissions from carryout and trackout and applies to all sites that are subject to any of the following rules where carryout or trackout has occurred or may occur on paved public roads or the paved shoulders of a paved public road.

Rule 8051 (Open Areas) limits fugitive dust emissions from open areas and applies to any open area having 0.5 acre or more within urban areas, or 3.0 acres or more within rural areas; and contains at least 1,000 square feet of disturbed surface area.

Rule 8061 (Paved and Unpaved Roads) limits fugitive dust emissions from paved and unpaved roads by implementing control measures and design criteria.

Rule 8071 (Unpaved Vehicle/Equipment Traffic Areas) limits fugitive dust emissions from unpaved vehicle and equipment traffic areas.

Regulation IX (Mobile and Indirect Sources)

Rule 9410 (Employer Based Trip Reduction) reduces vehicle miles traveled from private vehicles used by employees to commute to and from their worksites to reduce emissions of NO_X, VOC, and PM.

Rule 9510 (Indirect Source Review). Indirect sources are land uses that attract or generate motor vehicles trips. Indirect source emissions contain many pollutants, principally PM_{10}, ROG, and NO_X. The San Joaquin Valley Air Pollution Control District (SJVAPCD) first implemented this requirement in the adopted 2003 PM_{10} Plan to develop and implement an Indirect Source Rule (ISR) by July 2004, with implementation to begin in 2005. Senate Bill 709 (SB 709) (Florez 2003) as required the SJVUAPCD to adopt by regulation a schedule of fees to be assessed on areawide and indirect sources of emissions. After public hearings, the Air District adopted Rule 9510 on December 15, 2005, and it became effective in 2006. This rule was amended on December 21, 2017, and the amendments came into effect on March 21, 2018.

The purpose of Rule 9510 is to reduce emissions of NO_X and PM_{10} from new development projects. The District determined that reducing one precursor NO_X, would reduce the cumulative impact on ozone form new development to less than significant levels. Sufficient ROG was obtained from other control measures to enable the District to predict attainment without additional ROG controls. The rule applies to development projects that seek to gain a discretionary approval for projects that, upon full buildout, will include any one of the following: 50 residential units; 2,000 square feet of commercial space; 25,000 square feet of light industrial space; 20,000 square feet of medical or recreational space; 39,000 square feet of general office space; 100,000 square feet of heavy industrial space; 9,000 square feet of educational space; 10,000 square feet of government space; or 9,000 square feet of any land use not identified above. Several sources are exempt from the rule, including transportation projects, transit projects, reconstruction projects that result from a natural disaster, and development projects whose primary source of emissions are subject to district Rules 2201 and 2010, which address stationary sources. Any development project that has a mitigated baseline of less than 2 tons per year for each NO_X and PM_{10} is exempted from the mitigation requirements of the rule as well as Oil and Gas activities (which involve development projects on facilities whose primary functions are subject to Rule 2201 [New and Modified Stationary Source Review Rule] or Rule 2010 [Permits Required]). Developers are encouraged to reduce as much air pollution as possible through onsite mitigation, or incorporating air-friendly designs and practices into the Project. Some examples include; bike paths and sidewalks, traditional street design; medium- to high-density residential developments; locating near bus stops and bike paths; locating near different land use zones, such as commercial; and increasing energy efficiency. If these practices do not completely meet the required reductions then, under the rule, new development projects are required to mitigate the remainder of their emissions by contributing to a mitigation fund that would be used to pay for the most cost-effective projects to reduce emissions. Examples of such projects include retirement and crushing of gross polluting cars, replacement of older diesel engines, and diesel-powered vehicles and programs that would encourage the replacement of gas-powered lawn mowers with electric lawn mowers.

The ISR requires developers to reduce 20% of construction-exhaust NO_X, 45% of construction-exhaust PM_{10}, 33% of operational NO_X over 10 years, and 50% of operational PM_{10} over 10 years. The District estimates that the potential reductions from this program in 2010 at 11.5 tons per day, or 4,197.5 tons per year, of PM_{10} and 4.1 tons per day, or 1,496.5 tons per year, of NO_X.

Emission Reduction Agreements

The implementation, as mitigation, of a Development Mitigation Contract or Voluntary Emission Reduction Agreement (VERA) to reduce criteria pollutants of NO_X, ROGs, and PM net incremental emissions generated by a project has been incorporated into development projects in Kern County since 2008. They are not a "voluntary" agreement with the SJVAPCD but are mandated by enforceable mitigation measures and are, therefore, called Development Mitigation Contracts (DMC). The emission reductions required by a DMC are implemented within the SJVAB in quantities sufficient to fully mitigate the Project's air quality impacts such that development of the Project could be considered to result in no net increase in the designated criteria pollutant emissions over the criteria pollutant emissions that would otherwise exist without the development of the Project, all to be verified by the SJVAPCD. Thus, the DMC results in greater reductions than would otherwise occur under the District's ISR, since the ISR does not require ROG reductions and the ISR only requires a percentage of reductions rather than full reductions of NO_X and PM resulting from Project construction and operations. When adopting the ISR and the subsequent VERA/DMC programs, the District acknowledges that as ROG is a precursor to ozone, the reductions are not required in the ISR. In the VERA/DMC, the reductions are achieved by increasing the NO_X and PM tonnage for Project levels (SJVAPCD 2005a). As the actual amount of ROG reductions achieved from NO_X and PM reductions is not absolutely certain, Project emissions are still considered significant and unavoidable; however, all feasible and reasonable mitigation has been required to reduce criteria pollutants as close to "no net increase" as scientifically possible. This approach has been found legally sufficient by court rulings in the following cases; California Building Industry Assn. v. San Joaquin Valley APCD, Fresno County

Case No. 06 CECG 02100 DS13. National Association of Home Builders v. San Joaquin Valley Unified Air Pollution Control District; Federal District Court, Eastern District of California, Case No. 1:07-CV-00820-LJO-DLB; and Center for Biological Diversity et al. v Kern County, Fifth Appellate District, Case No. F061908.

Local Control Measures

The SJVAPCD requires all local governments within its eight-county jurisdiction to adopt resolutions as part of the Ozone Attainment Demonstration Plan that must be approved by EPA. The resolutions describe the reasonably available control measures that each jurisdiction will implement to reduce ozone-causing emissions into the air from transportation sources. Local jurisdictions are also required to adopt best available control technology measures to reduce particle emissions as part of the PM_{10} Area Attainment Demonstration Plan. This process is coordinated and assisted by regional transportation planning agencies, such as the Kern COG.

The Kern County Board of Supervisors adopted a resolution on March 12, 2002, that committed the County to implementing several measures to reduce ozone-causing emissions. Among the measures are cost incentives for road contractors to minimize land closures, transit-oriented land use planning, and measures to encourage County employees and other motorists to restrict driving on days with high ozone levels as well as continuing efforts to convert County vehicles to low-emission compressed natural gas and gasoline/electric hybrid engines. Many of these measures have been incorporated as general plan policies.

The Kern County Board of Supervisors adopted a resolution on January 7, 2003, that committed the committed the County to implement several measures aimed at reducing PM_{10} emissions from County roadways. Among the measures are plans to determine the feasibility of paving the County's unpaved roads, which are lightly traveled; paving the shoulders of the most heavily traveled paved County roads as funding allows; and purchasing two PM_{10}-compliant street sweepers as funding allows. The resolution also committed the County to imposing tougher rules for cancelling road improvements on large rural parcels; requiring public and private access roads for new commercial and industrial development to be paved; evaluating the adverse air quality impacts of new development and, where appropriate, requiring mitigation measures; implementing policies that require developers to control and abate dust during grading and construction operations; and to receive a permit for expansion or a significantly altered use, requiring unpaved parking and storage areas of commercial and agricultural operations in County areas to be paved. These measures are being implemented through the Kern County Land Division Ordinance, Kern County Zoning Ordinance (Zoning Ordinance), and in the approved General Plan.

Air Quality Plans

The SJVAPCD has developed plans to attain State and federal standards for ozone and PM. The District's air quality plans include emissions inventories to identify the sources and quantities of air pollutants, to evaluate how well different control methods have worked, and to demonstrate how air pollution will be reduced. The plans also use computer modeling to estimate future levels of pollution and make sure that the Valley will meet air quality goals. The SJVAPCD's attainment plans are subject to approval by the SJVAPCD's Governing Board. At the time of this writing, the following attainment plans were in effect.

The adopted plans include emissions inventories, projected changes in population, vehicles, fuels and equipment, and associated emissions. The plans then identify existing rules and additional proposed measures required to reduce emissions to the ambient air quality standards. These rules and proposed measures include requirements to obtain permits to construct and operate, and rules regulating the allowable emissions from various activities or classes of equipment.

One-Hour Ozone Plan

CARB submitted the 2004 Extreme Ozone Attainment Demonstration Plan to the EPA on November 15, 2004. The plan was amended by the District in 2008. Effective June 15, 2005, the EPA revoked the federal 1-hour ozone ambient air quality standard, finding that the 8-hour ozone standard was more health protective and adopted anti-backsliding provisions to preserve existing 1-hour ozone control measure and emissions reductions obligations; this delayed EPA action on the District's 2004 Plan until 2010. The SJVAPCD implemented the 2004 plan's control measures and emissions reductions strategies, and the Valley must still attain the revoked standard before it can rescind the CAA Section 185 fees collected under Rule 3170.

In 2012, the EPA withdrew its 2010 approval of the SJVAPCD's 2004 Plan and required submittal of a new plan for the revoked 1-hour standard that includes the following:

- A Rate of Progress (ROP) demonstration;
- Contingency measures for ROP and for attainment;
- An attainment demonstration;
- A demonstration for Reasonably Available Control Measures (RACM);
- A demonstration for clean fuels/clean technologies are in place for boilers; and
- A vehicle miles traveled offset demonstration.

The SJVAPCD's Governing Board adopted the 2013 Plan for the Revoked 1-Hour Ozone Standard in September 2013, thereby fulfilling air quality planning requirements under the federal CAA for the Revoked 1-Hour Ozone Standard. The District Governing Board also requested the EPA to set 2017 as the attainment date for the revoked 1-hour ozone NAAQS, adopted in 1979.

On July 13, 2015, the SJVAPCD submitted a second formal request that the EPA determine that the Valley has attained the federal 1-hour ozone standard, allowing nonattainment penalties to be lifted under federal CAA Section 179B.

On July 18, 2016, the EPA published in the Federal Register a final action determining that the SJV has attained the 1-hour ozone NAAQS. This determination was based on the most recent three-year period (2012 to 2014) of sufficient, quality-assured, and certified data (SJVAPCD n.d.[a]).

Eight-Hour Ozone Plan

In June 2016, the District adopted the 2016 Plan, addressing the federal mandates related to the 2008 8-hour ozone NAAQS. The 2016 Ozone Plan sets out the strategy to attain the 75 ppb standard by 2031, ensuring expeditious attainment of the CAA. This requires another 207.7 tons per day in NO_X reductions from stationary and mobile sources throughout the SJV. The measures identified in this plan were designed to achieve the necessary reductions (SJVAPCD 2016*a*).

CARB approved the plan on July 21, 2016. In response to court decisions, some elements included in the 2016 Ozone Plan required updates. CARB staff prepared the 2018 Updates to the California SIP (2018 SIP Update) to update SIP elements for nonattainment areas throughout the State as needed. CARB adopted the 2018 SIP Update on October 25, 2018 (CARB 2019).

PM_{10} Maintenance Plan

Based on PM_{10} measurements from 2003 to 2006, the EPA found that the SJVAB has reached federal PM_{10} standards. On September 21, 2007, the SJVAPCD adopted the 2007 PM_{10} Maintenance Plan and Request for Redesignation. This plan demonstrates that the Valley will continue to meet the PM_{10} standard. The EPA approved the document and on September 25, 2008, the SJVAB was re-designated to attainment for PM_{10} NAAQS.

2008 $PM_{2.5}$ Plan

The SJVAB is designated nonattainment for federal $PM_{2.5}$ standards. The EPA set their first $PM_{2.5}$ standards in 1997, and they strengthened the 24-hour standard in 2006. The SJVAPCD's Governing Board adopted the 2008 $PM_{2.5}$ Plan on April 30, 2008. The plan estimated that the SJVAB would reach the $PM_{2.5}$ standard by 2014. The CARB approved the Plan on May 22, 2008. The EPA approved most provisions of the 2008 $PM_{2.5}$ Plan effective January 9, 2012.

2012 $PM_{2.5}$ Plan

The SJVAPCD adopted the 2012 $PM_{2.5}$ Plan on December 20, 2012. The plan demonstrated that the SJVAB would achieve the 2006 24-hour $PM_{2.5}$ NAAQS of 35 micrograms per cubic meter ($\mu g/m^3$) by 2019. The CARB approved the SJVAPCD's 2012 $PM_{2.5}$ Plan in January 2013. The EPA approved most provisions of the 2012 $PM_{2.5}$ Plan effective August 31, 2016.

2015 $PM_{2.5}$ Plan

The SJVAPCD adopted the 2015 $PM_{2.5}$ Plan for the 1997 $PM_{2.5}$ standard in April 2015. While nearly achieving the 1997 standards by 2014, as predicted in the 2008 $PM_{2.5}$ Plan, the SJVAB experienced higher $PM_{2.5}$ levels in winter 2013 to 2014 due to the extreme drought, stagnation, strong inversions, and historically dry conditions; thus, the SJVAB was unable to meet the attainment date of December 31, 2015. Accordingly, the plan asked for a one-time extension of the attainment deadline for the 24-hour standard to 2018 and the annual standard to 2020.

The 2015 $PM_{2.5}$ Plan builds on past development and implementation of effective control strategies and, consistent with EPA regulations for $PM_{2.5}$, planned to achieve the 1997 standard as expeditiously as possible. The plan contains Most Stringent Measures, Best Available Control Measures, and additional enforceable commitments to further reduce emissions to ensure expeditious attainment of the 1997 standard.

The EPA formally proposed to approve portions of the 2015 $PM_{2.5}$ Plan and the attainment date extension on February 9, 2016. The EPA needed to finalize its approval of the SJVAPCD's attainment date extension by July 2016, but the EPA failed to finalize this action. The EPA subsequently denied the SJVAPCD's attainment extension request on the basis that they did not have enough information to act, and found that the SJVAPCD failed to attain the 1997 standard by its December 2015 attainment deadline. The EPA's action was effective December 23, 2016.

2016 Moderate Area Plan for the 2012 $PM_{2.5}$ Standard

The SJVAPCD adopted the 2016 Moderate Area Plan for the 2012 $PM_{2.5}$ Standard on September 15, 2016. This plan addresses the EPA federal annual $PM_{2.5}$ standard of 12 $\mu g/m^3$, established in 2012. This plan includes an attainment impracticability demonstration and request for reclassification of the SJVAB from Moderate nonattainment to Serious nonattainment.

2018 Plan for the 1997, 2006, and 2012 $PM_{2.5}$ Standards

The SJVAPCD adopted the 2018 Plan for the 1997, 2006, and 2012 $PM_{2.5}$ Standards on November 15, 2018. This plan addresses the EPA federal 1997 annual $PM_{2.5}$ standard of 15 $\mu g/m^3$ and 24-hour $PM_{2.5}$ standard of 65 $\mu g/m^3$; the 2006 24-hour $PM_{2.5}$ standard of 35 $\mu g/m^3$; and the 2012 annual $PM_{2.5}$ standard of 12 $\mu g/m^3$. The plan demonstrates attainment of the $PM_{2.5}$ standards, as expeditiously as possible, with estimates that the EPA federal 1997 annual $PM_{2.5}$ standard of 15 $\mu g/m^3$ and 24-hour $PM_{2.5}$ standard of 65 $\mu g/m^3$ will be attained by 2020, the 2006 24-hour $PM_{2.5}$ standard of 35 $\mu g/m^3$ will be attained by 2024, and the 2012 annual $PM_{2.5}$ standard of 12 $\mu g/m^3$ will be attained by 2025. CARB approved the SJVAPCD's 2018 $PM_{2.5}$ Plan in January 2019. The Plan is currently being considered for approval by the EPA.

The SJVAPCD attainment strategy builds on comprehensive strategies already in place from previously adopted attainment plans and measures. The SJVAPCD's multi-faceted approach to reducing emissions in the SJVAB for this Plan consists of a combination of innovative regulatory and non-regulatory measures (SJVAPCD 2018*a*).

As of 2016, the SJVAPCD's Bakersfield, Visalia, Fresno, and Stockton $PM_{2.5}$ monitoring sites have all achieved the EPA 24-hour $PM_{2.5}$ standard of 65 $\mu g/m^3$ (CARB 2019). However, as explained in Table 4.3-2, the SJVAPCD remains nonattainment for $PM_{2.5}$ and further reductions are needed to meet the federal 1997 annual $PM_{2.5}$ standard of 15 $\mu g/m^3$, the 2006 24-hour $PM_{2.5}$ standard of 35 $\mu g/m^3$ and the 2012 annual $PM_{2.5}$ standard of 12 $\mu g/m^3$.

Air Quality Conformity Determination for Transportation Plans and Programs

The CAA amendments of 1990 require a finding to be made stating that any project, program, or plan subject to approval by a metropolitan planning organization conforms to air plans for attainment of air quality standards. Kern COG is designated the Regional Transportation Planning

Agency and Metropolitan Planning Organization for Kern County. In that capacity, Kern COG models air quality projections on population projections in conjunction with current general plan designations and estimated vehicle miles as well as the current Regional Transportation Plan (RTP) and the federal transportation plan for Kern County finalized in August 16, 2018. Kern County is contained within two air basins: the SJVAB and the MDAB. Each air basin has its own plans and pollutant budgets. Kern COG makes conformity findings for each air basin (FHWA 2018). The Federal Transportation Improvement Program (FTIP) for the Kern County region is a six-year schedule of multimodal transportation improvements, and the RTP is a long-range, 26-year transportation and sustainability plan.

The Conformity Analysis for the 2019 FTIP and 2018 RTP was adopted by Kern COG August 16, 2018, and approved by the Federal Highway Administration and the Federal Transit Administration on December 3, 2018. The regional emissions analysis was conducted for the years 2017, 2018, 2019, 2020, 2021, 2024, 2027, 2030, 2031, 2035, and 2040 for each applicable pollutant. The conformity findings conclude that the FTIP and RTP result in emissions that are less than the emission budgets of baseline emissions or approved trading mechanisms for transportation conformity purposes for CO, VOC, NO_X, PM_{10}, and $PM_{2.5}$ (FHWA 2017).

Guide for Assessing and Mitigating Air Quality Impacts/Air Quality Thresholds of Significance

In August 1998, the SJVAPCD adopted its Guide for Assessing and Mitigating Air Quality Impacts (GAMAQI) to provide lead agencies, consultants, and project applicants with uniform procedures for addressing air quality in environmental documents. The District subsequently revised its GAMAQI document in January 2002 (SJVAPCD 2002). In 2012, the SJVAPCD began the process to update its GAMAQI document. The update was intended to codify long-standing district practices, provide updated data, revise recommended significance thresholds, and provide additional technical guidance. The May 2012 Draft GAMAQI is more environmentally protective than the January 2002 GAMAQI. In March 2015, the SJVAPCD again updated the GAMAQI. This document utilizes the significance thresholds recommended in its March 2015 Final GAMAQI (SJVAPCD 2015).

In December 2006, the Kern County Planning and Natural Resources (KCPNR) issued its own Guidelines for Preparing an Air Quality Assessment for Use in Environmental Impact Reports (Kern County Air Quality Assessment Guidelines). The document provided specific guidance for County-prepared environmental impact reports, including air quality issues to be considered, analytical approaches and resources, a significance threshold for PM_{10} (which was not reflected in the January 2002 GAMAQI, but is included in the March 2015 Final GAMAQI), and a cumulative impact analysis methodology (KCPD 2006). This analysis also utilizes the analytical approach and issues recommended in the KCPNR's Guidelines.

Criteria Pollutant Emissions

Table 4.3-8 presents the SJVAPCD's criteria pollutant emissions significance thresholds for construction and Project operation, based on the District's Final March 2015 GAMAQI. As shown in Table 4.3-8, the SJVAPCD recommends that emissions from permitted sources and activities be evaluated separately from non-permitted sources and activities.

Table 4.3-8: Criteria Pollutant Emissions Significance Thresholds (tons per year)

Pollutant/ Precursor	Construction Emissions	Operational Emissions	
		Permitted Sources and Activities	Non-Permitted Sources and Activities
ROG	10	10	10
NO_X	10	10	10
PM_{10}	15	15	15
$PM_{2.5}$	15	15	15
CO	100	100	100
SO_X	27	27	27

Source: SJVAPCD 2015, Section 8.3.
Key:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SO_X = sulfur oxides

As indicated in the 2015 GAMAQI, permitted sources and activities are subject to SJVAPCD Regulation II (Permits), notably Rule 2201 (New and Modified Stationary Source Review) and Rule 2301 (Emission Reduction Credit Banking). Rule 2201 requires that any emission increases from new permitted stationary sources are mitigated by emission *trade-offs, which can include Emission Reduction Credits (ERCs), emission reductions due to control measures, or other decreases in emissions at a facility site (such as shutting down other equipment).* ~~offsets.~~ In most cases, permitted stationary source emissions, therefore, will be reduced or mitigated to below the SJVAPCD's recommended significance thresholds (SJVAPCD 2015, Section 8.2.1).

While CARB recently performed an audit of the SJVAPCD ERC Banking Program, CARB did not overturn the program (CARB 2020b, 2020c). Subsequently, the SJVAPCD Board approved staff recommendations to remove Ag-ICE projects from the NO_X ERC equivalency system and to remove orphan shutdown projects from the VOC ERC equivalency system, effective September 17, 2020 (SJVAPCD 2020). This action means that the SJVAPCD cannot demonstrate federal equivalency with the surplus value test for NO_X and VOC and thus any new major source or federal major modification triggering NO_X or VOC offsets under Rule 2201 will require "surplus at time of use" ERCs, which means ERCs must be demonstrated to be surplus at the time an ATC is issued, rather than at the time that the emission reductions began. This process will remain in place until such time that equivalency with the federal program is again demonstrated by the SJVAPCD. This step by the SJVAPCD thus restricts the allowable number of ERCs that are valid for use as offsets in *the Valley, but does not change the way that ERCs are used nor does it change permitting requirements under Rule 2201. Thus, permitted stationary sources will only be allowed to move forward and be permitted by the SJVPACD if emissions are properly offset and if the SJVPACD approves an ATC, as required by Rule 2201. Therefore, it is reasonable to assume that permitted stationary source emissions will continue to be offset under SJVAPCD rules and reduced or mitigated to below SJVAPCD's recommended significance thresholds.*

Criteria Pollutant Modeling

The SJVAPCD's 2015 GAMAQI states that a project should be considered to have a significant impact if its emissions would cause or contribute to a violation of any CAAQS or NAAQS (SJVAPCD 2015, Section 8.4.). Accordingly, this analysis utilizes applicable CAAQS or NAAQS to establish thresholds of significance for pollutants subject to a standard for which the SJVAB is designated attainment or unclassified. For pollutants subject to a standard for which the SJVAB is designated non-attainment, this analysis utilizes the EPA's Significant Impact Levels, as shown in Table 4.3-9.

Table 4.3-9: Criteria Pollutant Ambient Concentration Significance Thresholds

Pollutant	Averaging Period	EPA Significant Impact Levels[a] ($\mu g/m^3$)	Applicable Ambient Air Quality Standards[b] ($\mu g/m^3$)	Significance Threshold ($\mu g/m^3$)
NO_2	1 hour	7.5	339 (California) 188.7 (Federal)	339 (California)[c] 188.7 (Federal)[c]
	Annual	1	57 (California) 100 (Federal)	57[c]
PM_{10}	24 hours	5	50 (California) 150 (Federal)	increase > 5[d]
	Annual	1	20 (California)	increase > 1[d]
$PM_{2.5}$	24 hours	1.2	35 (Federal)	increase > 1.2[d]
	Annual	0.3	12 (California, Federal)	increase > 0.3[d]
CO	1 hour	2,000	23,000 (California) 40,000 (Federal)	23,000[c]
	8 hours	500	10,000 (California, Federal)	10,000[c]

Table 4.3-9: Criteria Pollutant Ambient Concentration Significance Thresholds

Pollutant	Averaging Period	EPA Significant Impact Levels[a] (µg/m^3)	Applicable Ambient Air Quality Standards[b] (µg/m^3)	Significance Threshold (µg/m^3)
SO_2	1 hour	7.8	655 (California) 196 (Federal)	655 (California)[c] 196 (Federal)[c]
	3 hours	25	1,300 (Federal)	1,300[c]
	24 hours	5	105 (California)	105[c]

Notes:
(a) Source: SJVAPCD 2013b.
(b) Source: CARB 2016, Table 3-1.
(c) Since the San Joaquin Valley Air Basin (SJVAB) is designated unclassifiable or attainment for California and federal NO_2, CO, and SO_2 standards, the significance thresholds are based on the most restrictive applicable ambient air quality standards. Because the federal one-hour NO_2 and SO_2 standards have different forms than California one-hour NO_2 and SO_2 standards, significance thresholds are based on both California and federal one-hour NO_2 and SO_2 ambient standards.
(d) Since the SJVAB is designated nonattainment for California PM_{10} standards, and nonattainment for California and federal $PM_{2.5}$ standards, significance thresholds are based on U.S. Environmental Protection Agency Significant Impact Levels.

Key:
µg/m^3 = micrograms per cubic meter
CO = carbon monoxide
NO_2 = nitrogen dioxide
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SO_2 = sulfur dioxide

Odors

The SJVAPCD recommends that lead agencies assess odor significance based on a review of District complaint records. For a project locating near an existing source of odors, the impact is potentially significant when the project site is at least as close as any other site that has already experienced significant odor problems related to the odor source. Significant odor problems are defined as:

- More than one confirmed complaint per year averaged over a three-year period; or
- Three unconfirmed complaints per year averaged over a three-year period.

A complaint is deemed unconfirmed if the odor/air contaminant release could not be detected, or the source/facility cannot be determined.

The Kern County Air Quality Assessment Guidelines recommend dispersion modeling of maximum 24–hour average concentrations of odorous compounds at the Project boundary and within a 6-mile limit to determine ambient concentrations at nearby sensitive receptors (e.g., residences and schools), including approved, but not constructed sensitive receptors. Ambient concentrations at such receptors should be compared to odor thresholds and California Environmental Quality Act (CEQA) impact thresholds to determine potential odor impacts.

Air Toxic Program

In the context of toxic air contaminants, to meet the requirements of federal and State law, the SJVAPCD has created an Integrated Air Toxic Program. This program serves as a tool for implementation of the requirements outlined in Title III of the 1990 CAA Amendments and the TAC-related requirements of State law and District regulations. The goals of SJVAPCD risk management efforts are to: (1) minimize increases in toxic emissions associated with new and modified sources of air pollution; and (2) ensure that new and modified sources of air pollution do not pose unacceptable health risks at nearby residences and businesses.

To achieve these goals, the SJVAPCD reviews the risk associated with each permitting action where there is an increase in emissions of TACs. SJVAPCD staff, as part of the engineering evaluation for these projects, performs this risk management review. The risk management review is performed concurrently with other project review functions necessary to process permit applications with the SJVAPCD.

Under the Agency's risk management policy, toxic best available control technology must be applied to all units that, based on their potential emissions may pose greater than de minimis risks. Facilities that pose health risks above SJVAPCD action levels are required to submit plans to reduce their risk. Action levels for risk were established in the SJVAPCD's Board-Approved HRRS. The action level for cancer risk was 10 cases per 1 million exposed persons, based on the maximum exposure beyond facility boundaries at a residence or business. Following changes to the State HRA Guidelines (discussed in Impact 4.3-4), the SJVAPCD changed its cancer risk action level to 20 per 1 million in a policy dated May 28, 2015 (APR-1906 "Framework for Performing Health Risk Assessments"). The action level for non-cancer risk is a hazard index of 1.0 at any point beyond the facility boundary where a person could reasonably experience exposure to such risk.

SJVAPCD Health-Risk Reduction Strategy (HRRS)

In 2010, the SJVAPCD Governing Board adopted the Risk-Based Strategy, which focuses on measures that address the pollutants for which the Valley is working toward attainment: ozone and fine-PM. This strategy is also gaining widespread support by the EPA and the scientific community. In May 2013, the SJVAPCD renamed its Risk-Based Strategy as the Health-Risk Reduction Strategy (HRRS).

Driven by a rapidly expanding body of scientific research, there is now a growing recognition within the scientific community that from an exposure perspective, the NAAQS metrics for progress are a necessary, but increasingly insufficient, measure of total public health risk associated with air pollutants. In particular, control strategies for sources of $PM_{2.5}$ and ozone do not necessarily account for qualitative differences in the nature of their emissions. For $PM_{2.5}$, toxicity has been shown to vary depending on particle size, chemical species, and surface area. In the case of ozone, differences in the relative potency of ozone precursors, VOCs in particular, is not captured by a strict, mass-based approach to precursor controls. Thus, while the NAAQS and SIP process is motivated by public health, the process set forward under the CAA does not guarantee that the public health benefits of control strategies will be maximized.

The HRRS applies to regulatory, incentive, and outreach strategies and recognizes that risk to the public is not always proportional to the mass rate of emissions based on factors such as:

- Ultrafine particles versus coarse particles;
- Toxicity/carcinogens;
- Intake fraction/deposition fraction;
- NO_X versus VOCs;
- NO_X versus ammonia reductions; and
- Photochemical reactivity of VOCs.

The HRRS does not establish a new acceptable risk level, delay attainment of mass-based air quality standards, or ask for a change in the form of the mass-based air quality standards. Instead, it describes how to determine the potential risk to public health from a particular project.

SJVAPCD Policy APR 1905

In Policy APR 1905, the SJVAPCD establishes three stages for risk evaluation for all projects resulting in increases in hourly, daily, or annual potential to emit hazardous air pollutants from new and modified sources, except projects specifically exempted in approved SJVAPCD permitting policies. The stages are the following:

A. Prioritization

Projects shall be prioritized using the California Air Pollution Control Officers Association (CAPCOA) Facility Prioritization Guidelines. A prioritization score is used for determining the applicability of toxic best available control technology to each new and modified emissions units and the need for a detailed HRA.

B. Health Risk Assessment

Projects with cumulative increases in prioritization score of greater than one require an HRA using the OEHHA Guidelines.

C. Calculation of Increase in Permitted Emissions

Increase is determined as the difference between the baseline and proposed Potential to Emit for the pollutant. APR 1905 specifies that the SJVAPCD policy defining certain small increases of criteria pollutant emissions as zero does not apply to hazardous air pollutants.

Kern County General Plan

The Project Area is located within the Kern County General Plan (KCGP) area and, therefore, would be subject to applicable policies and measures of the KCGP. The Land Use, Conservation, and Open Space Element; Safety Element; and the Energy Element of the KCGP include goals, policies, and implementation measures related to air quality that apply to the Project, as described below.

Chapter 1. Land Use, Conservation, and Open Space Element

1.10.2. Air Quality

Policies

Policy 19. In considering discretionary projects for which an environmental impact report must be prepared pursuant to the California Environmental Quality Act, the appropriate decision making body, as part of its deliberations, will ensure that:

a) All feasible mitigation to reduce significant adverse air quality impacts have been adopted; and

b) The benefits of the proposed Project outweigh any unavoidable significant adverse effects on air quality found to exist after inclusion of all feasible mitigation. This finding shall be made in a statement of overriding considerations and shall be supported by factual evidence to the extent that such a statement is required pursuant to the CEQA.

Policy 20. The County shall include fugitive dust control measures as a requirement for discretionary projects and as required by the adopted rules and regulations of the San Joaquin Valley Unified Air Pollution Control District and the Kern County Air Pollution Control District on ministerial permits.

Policy 21. The County shall support air districts' efforts to reduce PM_{10} and $PM_{2.5}$ emissions.

Policy 22. Kern County shall continue to work with the San Joaquin Valley Unified Air Pollution Control District and the Kern County Air Pollution Control District toward air quality attainment with federal, State, and local standards.

Policy 23. The County shall continue to implement the local government control measures in coordination with the Kern Council of Governments and the San Joaquin Valley Unified Air Pollution Control District.

Implementation Measures

Implementation Measure F. All discretionary permits shall be referred to the appropriate air district for review and comment.

Implementation Measure G. Discretionary development projects involving the use of tractor trailer rigs shall incorporate diesel exhaust reduction strategies including, but not limited to:

- Minimizing idling time.
- Electrical overnight plug-ins.

Implementation Measure H. Discretionary projects may use one or more of the following to reduce air quality effects:

- Pave dirt roads within the development.
- Pave outside storage areas.
- Provide additional low VOC producing trees on landscape plans.
- Use of alternative fuel fleet vehicles or hybrid vehicles.
- Use of emission control devices on diesel equipment.
- Develop residential neighborhoods without fireplaces or with the use of EPA-certified, low emission natural gas fireplaces.
- Provide bicycle lockers and shower facilities onsite.
- Increasing the amount of landscaping beyond what is required in the Zoning Ordinance (Chapter 19.86).
- The use and development of park and ride facilities in outlying areas.
- Other strategies that may be recommended by the local Air Pollution Control Districts.

Chapter 4. Safety Element

4.2. General Policies and Implementation Measure, which Apply to more than One Safety Constraint

Policies

Policy 1. That the County's program of identification, mapping, and evaluating the geologic, fire, flood safety hazard areas, and significant concentrations of hydrogen sulfide in oilfield areas, presently under way by various County departments, be continued.

Chapter 5. Energy Element

5.3.1. Urban/Residential Development in Petroleum Resource Areas

Policies

Policy 8. Reduce the public's exposure to fires, explosions, blowouts, and other hazards associated with the accidental release of crude oil, natural gas, or hydrogen sulfide gas by ensuring that discretionary development projects have adequate separation from oil and natural gas production land uses.

5.3.6. Environmental Impacts of Petroleum Development

Policies

Policy 4. The County should encourage the use of clean-burning technologies in petroleum production.

Policy 5. The County should encourage air pollution control policies which apply the burden equally to local and upwind sources and to all classes of air polluters.

Metropolitan Bakersfield General Plan

The Metropolitan Bakersfield General Plan (MBGP), a joint effort between the Kern County Planning and Natural Resources Department and the City of Bakersfield Planning Division, was last adopted on December 11, 2007. The MBGP includes both city and unincorporated County lands. The MBGP describes the community's physical development as well as its economic, social and environmental goals and is currently undergoing an update. The Project Area includes a total of 152,040 acres of unincorporated County lands that are covered under the MBGP (7.41%). Project-related development on unincorporated lands within the MBGP Planning Area would be subject to the following applicable policies and implementation measures of the MBGP, with respect to air quality.

Chapter V. Conservation Element

B. Mineral Resources

Goals

Goal 4. Protect land, water, air quality and visual resources from environmental damage resulting from mineral and energy resource development.

Policies

Policy 15. Require petroleum production sites in urban areas which are subject to discretionary permits, to install peripheral landscaping to help reduce the noise, dust and visual impacts to adjacent sensitive receptors and public ways (I-4).

E. Air Quality

Goals

Goal 1. Promote air quality that is compatible with health, well-being, and enjoyment of life by controlling point sources and minimizing vehicular trips to reduce air pollutants.

Goal 2. Continue working toward attainment of Federal, State and Local standards as enforced by the San Joaquin Valley Unified Air Pollution Control District.

Goal 3. Reduce the amount of vehicular emissions in the Planning Area.

Policies

Policy 1. Comply with and promote San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) control measures regarding Reactive Organic Gases (ROG). Such measures are focused on: (a) steam driven well vents, (b) Pseudo-cyclic wells, (c) natural gas processing plant fugitives, (d) heavy oil test stations, (e) light oil production fugitives, (f) refinery pumps and compressors, and (g) vehicle inspection and maintenance (I-1).

Policy 2. Encourage land uses and land use practices which do not contribute significantly to air quality degradation (I-1).

Policy 3. Require dust abatement measures during significant grading and construction operations (I-1).

Policy 5. Consider the location of sensitive receptors such as schools, hospitals, and housing developments when locating industrial uses to minimize the impact of industrial sources of air pollution (I-1).

Kern County Specific Plans

Kern County has adopted 24 Specific Plans for properties within the Project Area. These Specific Plans are intended to be an amplification of the goals and policies of the KCGP and are, therefore, consistent therewith. As discussed in Section 4.10, Land Use and Planning in the 2015 FEIR (SREIR Volume 3), less than 8% of the Project Area is located wholly or partially within adopted Specific Plan areas. Future oil and gas exploration and production activities that would be authorized under the proposed Amendment to Chapter 19.98 (Oil & Gas Production) of the Zoning Ordinance that would be located within the boundary of an adopted Specific Plan would be regulated according to County zoning, with the exception of the Specific Plans identified as Tier 5.

4.3.4 Impacts and Mitigation Measures

Methodology

This section discusses the methodologies used to conduct the evaluation of air quality impacts for the Project, including guidelines for preparing environmental documents under CEQA and technical methods employed in the evaluation. The air quality significance criteria were developed considering the CEQA significance criteria developed by the local air quality districts in the Project Area, which is the SJVAPCD, approved CEQA air quality checklists, and considering other federal criteria.

The baseline for purposes of this analysis is considered to be the physical environmental conditions existing as of the beginning of environmental analysis (2012) according to KCPNR, which have determined that the level of activity occurring during 2012 is representative of the Project's baseline conditions. The change in the environment caused by the Project results from oil and gas production and processing activities conducted between 2015 and 2035. No change in the baseline is required in this SREIR.

Thresholds of Significance

The CEQA Appendix G Checklist and the Kern County adopted CEQA thresholds state that a project would have a significant air quality impact if it would:

- Conflict with or obstruct implementation of the applicable air quality plan;
- Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is non-attainment under an applicable federal or state ambient air quality standard. Specifically, implementation of the project would have a significant impact on air quality if it would exceed any of the following adopted threshold:
  - i. San Joaquin Valley Unified Air Pollution Control District:

Operational and Area/Construction Sources	Reactive organic gases (ROG)	10 tons per year
	Oxides of nitrogen (NO_X)	10 tons per year
	Particulate matter (PM_{10})	15 tons per year
Stationary Sources (as Determined by District Rules)	Severe nonattainment	25 tons per year
	Extreme nonattainment	10 tons per year

- Expose sensitive receptors to substantial pollutant concentrations; and
- Result in other emissions (such as those leading to odors) adversely affecting a substantial number of people.

Project Impacts

Impact 4.3-1: Conflict with or Obstruct Implementation of the Applicable Air Quality Plan

The air pollution control districts and air quality management districts have the primary responsibility for controlling emissions from sources other than locomotives, motor vehicles and other specified statewide sources (such as consumer products), which are the responsibility of CARB or the EPA. Air districts adopt and enforce rules and regulations to ensure that emissions comply with national, state, and local emission standards, and will not interfere with the attainment and maintenance of the state and federal ambient air quality standards. The Project is located within the administrative boundaries of the SJVAPCD, which has jurisdiction over air quality in the SJVAB.

Future oil and gas exploration and production activities that would be authorized under the Project would result in emissions from stationary sources such as boilers, cogeneration plants, process heaters, reciprocating internal combustion engines, steam generators, production tanks, thermally enhanced oil recovery wells, and volatile organic compound destruction devices (VOCDD) (flares), and non-permitted sources (small equipment, well-related maintenance and treating operations, routine business travels). Air pollutants would also be emitted during Project construction (off-road construction equipment, on-road vehicles, fugitive PM from material movement, asphalt paving, and use of architectural coatings).

Consistency with Applicable Air Quality Plans

The SJVAPCD has developed plans to attain state and federal standards for ozone and PM. The District's air quality plans include emissions inventories to identify the sources and quantities of air pollutant emissions, evaluate how well different control methods have worked, and demonstrate how air pollution will be reduced. The plans also use computer modeling to estimate future levels of pollution to ensure that the Valley will meet air quality goals. As of June 2020, the following attainment/maintenance plans are in effect, as detailed in Section 4.3.3, Regulatory Setting, above.

One-Hour Ozone Plan

CARB submitted the SJVAPCD's 2004 Extreme Ozone Attainment Demonstration Plan to the EPA on November 15, 2004. The plan was amended by the District in 2008. Effective June 15, 2005, the EPA revoked the federal 1-hour ozone ambient air quality standard, finding that the 8-hour ozone standard was more health protective. Under federal anti-backsliding provisions, the District has continued to implement the 2004 plan's control measures and emissions reductions strategies. The District developed a new plan for EPA's revoked 1-hour ozone standard, which was adopted by the District's Governing Board on September 19, 2013. On July 13, 2015, the SJVAPCD submitted a second formal request that the EPA determine that the SJVAPCD has attained the federal 1-hour ozone standard. On July 18, 2016, the EPA took final action determining that the SJVAPCD has attained the 1-hour ozone NAAQS. This determination was based on the most recent three-year period (2012 to 2014) of sufficient, quality-assured, and certified data (SJVAPCD n.d.[a]).

Eight-Hour Ozone Plan

In June 2016, the District adopted the 2016 Plan, addressing the federal mandates related to the 2008 8-hour ozone NAAQS. The 2016 Ozone Plan sets out the strategy to attain the 75 ppb standard by 2031 (SJVACPD 2016*a*). CARB approved the plan on July 21, 2016. In response to court decisions, some elements included in the 2016 Ozone Plan required updates. CARB staff prepared the 2018 Updates to the California SIP (2018 SIP Update) to update SIP elements for nonattainment areas throughout the State as needed. CARB adopted the 2018 SIP Update on October 25, 2018 (CARB 2019).

PM_{10} Maintenance Plan

Based on PM_{10} measurements from 2003 to 2006, the EPA found that the SJVAB has achieved the federal PM_{10} NAAQS. On September 21, 2007, the District's Governing Board adopted the 2007 PM_{10} Maintenance Plan and Request for Redesignation. This plan demonstrates that the Valley will continue to meet the PM_{10} standard. The EPA approved the document and, effective December 12, 2008, the SJVAB was redesignated to attainment for the PM_{10} NAAQS.

2008 $PM_{2.5}$ Plan

The Valley is designated nonattainment for federal $PM_{2.5}$ standards. The EPA established its first $PM_{2.5}$ standards in 1997. The EPA strengthened the 24-hour standard in 2006 and the annual standard in 2013. Building on the strategy used in the 2007 Ozone Plan (SJVAPCD 2007), the District agreed to additional control measures to reduce directly produced $PM_{2.5}$. The District's Governing Board adopted the 2008 $PM_{2.5}$ Plan on April 30, 2008. The plan demonstrated that the SJVAB would achieve the 1997 annual $PM_{2.5}$ NAAQS of 15 μg/m^3 by 2014. CARB approved the Plan on May 22, 2008. The EPA approved most provisions of the 2008 $PM_{2.5}$ Plan effective January 9, 2012.

2012 $PM_{2.5}$ Plan

The SJVAPCD adopted the 2012 $PM_{2.5}$ Plan on December 20, 2012. The plan demonstrated that the SJVAB would achieve the 2006 24-hour $PM_{2.5}$ NAAQS of 35 μg/m^3 by 2019. CARB approved the Plan on January 24, 2013. The EPA approved most provisions of the 2012 $PM_{2.5}$ Plan effective August 31, 2016.

2015 $PM_{2.5}$ Plan

The SJVAPCD adopted the 2015 $PM_{2.5}$ Plan in April 2015. The plan asked for a one-time extension of the attainment deadline for the 1997 $PM_{2.5}$ 24-hour standard to 2018 and the annual standard to 2020. The 2015 $PM_{2.5}$ Plan contains most stringent measures, best available control measures, and additional enforceable commitments to ensure expeditious attainment of the 1997 standard. The EPA formally proposed to approve portions of the 2015 $PM_{2.5}$ Plan and the attainment date extension on February 9, 2016. The EPA needed to finalize its approval of the SJVAPCD's attainment date extension by July 2016, but the EPA failed to finalize this action. The EPA subsequently denied the SJVAPCD's attainment extension request and found that the SJVAPCD failed to attain the 1997 standard by its December 2015 deadline. The EPA's action was effective December 23, 2016.

2016 Moderate Area Plan for the 2012 $PM_{2.5}$ Standard

The SJVAPCD adopted the 2016 Moderate Area Plan for the 2012 $PM_{2.5}$ Standard on September 15, 2016. This plan addresses the EPA federal annual $PM_{2.5}$ standard of 12 μg/m^3, established in 2012. This plan includes an attainment impracticability demonstration and request for reclassification of the Valley from moderate nonattainment to serious nonattainment.

2018 Plan for the 1997, 2006, and 2012 $PM_{2.5}$ Standards

The SJVAPCD adopted the 2018 Plan for the 1997, 2006, and 2012 $PM_{2.5}$ Standards on November 15, 2018. This plan addresses the EPA federal 1997 annual $PM_{2.5}$ standard of 15 μg/m^3 and 24-hour $PM_{2.5}$ standard of 65 μg/m^3; the 2006 24-hour $PM_{2.5}$ standard of 35 μg/m^3; and the 2012 annual $PM_{2.5}$ standard of 12 μg/m^3. The plan demonstrates attainment of the $PM_{2.5}$ standards as expeditiously as possible, with estimates that the EPA federal 1997 annual $PM_{2.5}$ standard of 15 μg/m^3 and 24-hour $PM_{2.5}$ standard of 65 μg/m^3 will be attained by 2020, the 2006 24-hour $PM_{2.5}$ standard of 35 μg/m^3 will be attained by 2024, and the 2012 annual $PM_{2.5}$ standard of 12 μg/m^3 will be attained by 2025. CARB approved the SJVAPCD's 2018 $PM_{2.5}$ Plan in January 2019. The Plan is currently being considered for approval by the EPA (SJVACPD 2018).

Though the SJVAPCD did not attain the EPA federal 1997 annual $PM_{2.5}$ standard of 15 μg/m³ by 2014, as predicted by the 2008 $PM_{2.5}$ Plan, the Valley nearly reached this milestone and only missed its planned attainment date of December 31, 2015, due to higher $PM_{2.5}$ levels in winter 2013-2014 caused by the extreme drought, stagnation, strong inversions, and historically dry conditions. The subsequent $PM_{2.5}$ Plans (2015 and 2018) adopt most stringent measures, best available control measures, and additional enforceable commitments to further reduce emissions to ensure expeditious attainment of the 1997 standard. The 2018 plan demonstrates attainment as expeditiously as possible, with attainment of the federal 1997 annual $PM_{2.5}$ standard of 15 μg/m³ expected by 2020. As of 2016, the SJVAPCD's Bakersfield, Visalia, Fresno, and Stockton $PM_{2.5}$ monitoring sites have all achieved the EPA 24-hour $PM_{2.5}$ standard of 65 μg/m³ (CARB 2019). However, as explained in Table 4.3-2, the SJVAPCD remains nonattainment for $PM_{2.5}$ and further reductions are needed to meet the federal 1997 annual $PM_{2.5}$ standard of 15 μg/m³, the 2006 24-hour $PM_{2.5}$ standard of 35 μg/m³ and the 2012 annual $PM_{2.5}$ standard of 12 μg/m³. In addition, the 2018 Plan shows that $PM_{2.5}$ emissions from oil and gas production activities decreased from 2013 to 2017 and are projected to continue to decrease through 2028. (SJVAPCD 2018*a*)

The applicable air quality plans include emissions inventories, projected changes in population, vehicles, fuels and equipment, and the consequent changes in the associated emission levels over time to plan for attainment. The plans then identify existing rules and additional proposed measures that must be required to reduce emissions and ensure compliance with the ambient air quality standards. These rules and proposed measures include requirements to obtain permits to construct and operate, and rules regulating the allowable emissions from various activities or classes of equipment. The plans include various control measures and enforceable commitments to reduce emissions from various sources, including Project sources. Thus, the Project does not conflict with or obstruct applicable air quality plans if it will comply or be consistent with the rules and other measures in the plans.

Consistency with SJVAPCD Applicable Permits Required

SJVAPCD Rule 2010 (Permits Required) requires that an ATC Permit and a PTO be obtained prior to constructing, altering, replacing, or operating any device that emits or may emit air contaminants. Since the Project would require construction of various stationary source devices in Kern County, ATC Permits and Permits to Operate would be required.

SJVAPCD Rule 2410 (Prevention of Significant Deterioration) requires that pre-construction permits be obtained for new major stationary sources and major modifications to existing major stationary sources in areas classified as attainment or unclassifiable for any criteria pollutant. A stationary source or a modification is considered major if the net emissions increase equals or exceeds 40 tons per year VOC, 40 tons per year NO_X, 15 tons per year PM_{10}, 10 tons per year $PM_{2.5}$, 100 tons per year CO, or 40 tons per year SO_2. Stationary source emissions increases associated with the Project may exceed these thresholds, depending on the type of facility and new equipment to be built. Therefore, a PSD pre-construction permit may be required for the new oil and gas facilities of the Project.

Consistency with SJVAPCD Applicable Rules

Oil and gas activities that would be authorized under this Project would result in emissions from stationary sources (boilers, cogeneration plants, process heaters, reciprocating internal combustion engines, steam generators, production tanks, thermally enhanced oil recovery wells, and VOCDD [flares], storage tanks, loading and unloading racks, and fugitive emissions), and non-permitted sources (trucks, automobile work trips, and onsite vehicles). Air pollutants would be emitted during construction activities (off-road construction equipment, on-road vehicles, fugitive PM from material movement) and operational activities (employee and contractor commute and the transport of material, onsite travel to conduct day-to-day field operations, vehicle trips to perform maintenance). Following is a list of the SJVAPCD rules that could potentially apply to construction and operation activities that would be authorized under this Project.

Future oil and gas exploration and production activities that would be authorized under this Project would be required to comply with the relevant provisions of the following rules:

- Rule 2010 (Permits Required)
- Rule 2020 (Exemptions)
- Rule 2070 (Standards for Granting Applications)
- Rule 2201 (New and Modified New Source Review)
- Rule 2250 (Permit-Exempt Equipment Registration)
- Rule 2260 (Registration Requirements for Equipment Subject to California's Oil and Gas Regulation)
- Rule 2280 (Portable Equipment Registration)
- Rule 2410 (Prevention of Signification Deterioration)
- Rule 2520 (Federally Mandated Operating Permits)
- Rule 2540 (Acid Rain Program)
- Rule 2550 (Federally Mandated Preconstruction Review for Major Sources of Air Toxics)
- Rule 3135 (Dust Control Plan Fee)
- Rule 4001 (New Source Performance Standards)
- Rule 4002 (National Emission Standards for Hazardous Air Pollutants)
- Rule 4101 (Visible Emissions)
- Rule 4102 (Nuisance)
- Rule 4201 (Particulate Matter Concentration)

- Rule 4202 (Particulate Matter Emission Rate)
- Rule 4301 (Fuel Burning Equipment)
- Rule 4304 (Equipment Tuning Procedures for Boilers, Steam Generators, and Process Heaters)
- Rule 4305 (Boilers, Steam Generators and Process Heaters, Phase 2)
- Rule 4306 (Boilers, Steam Generators and Process Heaters, Phase 3)
- Rule 4307 (Boilers, Steam Generators, and Process Heaters 2.0 MMBtu/hr to 5.0 MMBtu/hr)
- Rule 4308 (Boilers, Steam Generators, and Process Heaters 0.075 MMBtu/hr to less than 2.0 MMBtu/hr)
- Rule 4311 (Flares)
- Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process
- Heaters Greater than 5.0 MMBtu/hr)
- Rule 4351 (Boilers, Steam Generators and Process Heaters, Phase 1)
- Rule 4352 (Solid Fuel Fired Boilers, Steam Generators, and Process Heaters)
- Rule 4401 (Steam Enhanced Crude Oil Production Wells)
- Rule 4402 (Crude Oil Production Sumps)
- Rule 4404 (Heavy Oil Test Station – Kern County)
- Rule 4405 (Oxides of Nitrogen Emissions from Existing Steam Generators used in Thermally Enhanced Oil Recovery – Central and Western Kern County Fields)
- Rule 4406 (Sulfur Compounds from Oil-Field Steam Generators – Kern County)
- Rule 4407 (In-Situ Combustion Well Vents)
- Rule 4408 (Glycol Dehydration Systems)
- Rule 4409 (Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities)
- Rule 4455 (Components at Petroleum Refineries, Gas Liquids Processing Facilities and Chemical Plants)
- Rule 4601 (Architectural Coatings)
- Rule 4612 (Motor Vehicle and Mobile Equipment Coating Operations)
- Rule 4621 (Gasoline Transfer into Stationary Storage Containers, Delivery Vessels, and Bulk Plants)
- Rule 4623 (Storage of Organic Liquids)

- Rule 4624 (Transfer of Organic Liquid)
- Rule 4625 (Wastewater Separators)
- Rule 4641 (Cutback, Slow Cure, and Emulsified Asphalt, Paving and Maintenance Operations)
- Rule 4642 (Solid Waste Disposal Sites)
- Rule 4651 (Soil Decontamination Operations)
- Rule 4661 (Organic Solvents)
- Rule 4662 (Organic Solvent Degreasing Operations)
- Rule 4663 (Organic Solvent Cleaning, Storage and Disposal)
- Rule 4701 (Internal Combustion Engines – Phase 1)
- Rule 4702 (Internal Combustion Engines)
- Rule 4703 (Stationary Gas Turbines)
- Rule 7050 (Asbestos - Containing Material for Surfacing Applications).
- Rule 4801 (Sulfur Compounds)
- Rule 8011 (General Requirements)
- Rule 8021 (Construction, Demolition, Excavation, Extraction, and Other Earthmoving Activities)
- Rule 8031 (Bulk Materials)
- Rule 8041 (Carryout and Trackout)
- Rule 8051 (Open Areas)
- Rule 8061 (Paved and Unpaved Roads)
- Rule 8071 (Unpaved Vehicle/Equipment Traffic Areas)
- Rule 9510 (Indirect Source Review)

Consistency with Applicable Indirect Source Review

On December 15, 2005, the SJVAPCD Governing Board adopted Rule 9510 (Indirect Source Review, or ISR). The District's ISR rule is intended to reduce NO_X and PM_{10} emissions from new development projects. Rule 9510 requires developers of specified development projects to submit applications and reduce emissions through onsite mitigation, offsite SJVAPCD-administered projects, or a combination of the two.

Rule 9510 exempts development projects for facilities with primary functions that are subject to District Rule 2201 (New and Modified Stationary Source Review Rule) or 2010 (Permits Required). The list of specific projects exempted under Rule 9510 includes "Gas Processing and Production" (Section 4.4.3.9). The oil and gas activities authorized under this Project involve construction of gas wells and gas processing facilities, and would be subject to Rules 2010 and 2201. Therefore, the Project is exempt from Rule 9510 under Section 4.4.3, more specifically under Section 4.4.3.9 (SJVAPCD 2005b).

Permitted Source Emissions

Emission increases associated with activities under the Project's permitted sources would come from boilers, cogeneration plants, process heaters, reciprocating internal combustion engines, steam generators, production tanks, thermally enhanced oil recovery wells, and VOCDD (flares). These sources would be subject to SJVAPCD prohibitory rules, notably Rule 4455 (Components at Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants) and Rule 4623 (Storage of Organic Liquids). Emissions from new permitted sources would also be required to be mitigated by emission offsets under Rule 2201 (New and Modified Stationary Source Review). *While CARB recently performed an audit of the SJVAPCD ERC Banking Program, which highlighted some potential issues with the program, CARB did not overturn the program (CARB 2020b, 2020c). Subsequently, the SJVAPCD Board approved staff recommendations to remove Ag-ICE projects from the NO_X ERC equivalency system and to remove orphan shutdown projects from the VOC ERC equivalency system, effective September 17, 2020 (SJVAPCD 2020b). This action means that the SJVAPCD cannot demonstrate federal equivalency with the surplus value test for NO_X and VOC and thus any new major source or federal major modification triggering NO_X or VOC offsets under Rule 2201 will require "surplus at time of use" ERCs, which means ERCs are demonstrated to be surplus at the time an Authority to Construct is issued rather than at the time that the emission reductions began. This process will remain in place until such time that equivalency with the federal program is again demonstrated by SJVAPCD. This step by the SJVAPCD thus restricts the allowable number of ERCs that are valid for use as offsets in the Valley, but does not change the way that ERCs are used nor does it change permitting requirements under Rule 2201. Thus, permitted stationary sources will only be allowed to move forward and be permitted by the SJVPACD if emissions are properly offset and if the SJVPACD approves an ATC, as required by Rule 2201.* Therefore, permitted source emissions would be consistent with the SJVAPCD's adopted regulatory program to attain state and federal ozone and PM standards.

Non-Permitted Source/Activity Emissions

Non-permitted sources and activities would be subject to the following federal and state regulatory programs that are incorporated within the attainment plans for state and federal ozone and PM standards:

- Heavy-duty engine and on-road vehicle standards enacted by CARB and the EPA (California Standards Codified at 13 CCR Section 1956.8).
- Light and medium on-road vehicle standards enacted by CARB (starting at 13 CCR Section 1900).

Non-permitted source/activity emissions were calculated using CARB's EMFAC2011 (January 2013) emissions model, which reflects adopted California on-road vehicle emission standards, and CARB's OFFROAD2011 model to generate fleet average emission factors for off-road mobile sources and portable equipment operated within the SJVAB. Fugitive dust emissions were calculated using predictive emission factors recommended by the EPA in AP42, Fifth Edition. Therefore, non-permitted source/activities would be consistent with adopted regulatory programs incorporated within the SJVAPCD's ozone and PM attainment plans.

Consistency with Kern County General Plan

Future oil and gas exploration and production activities that would be authorized under the Project would be required to comply with the policies and measures of the KCGP as discussed in greater detail in Section 4.10, Land Use and Planning, of the 2015 FEIR (SREIR Volume 3).

Consistency with the Metropolitan Bakersfield General Plan

Future oil and gas exploration and production activities that would be authorized under the Project would have to comply with the Metropolitan Bakersfield General Plan policies, which are applicable to County land, as discussed in greater detail in Section 4.10, Land Use and Planning, of the 2015 FEIR (SREIR Volume 3).

Oil and gas activities that would be authorized under the Project could conflict with or obstruct implementation of the applicable air quality plan or potentially be inconsistent with the General Plan measures and, therefore, could be significant.

Mitigation measures have been included to provide consistency with adopted General and Specific plans and applicable plans by the San Joaquin Air Pollution Control District.

The following mitigation measures have been clarified:

Clarified MM 4.3-2 The Applicant shall develop and implement a Fugitive Dust Control Plan in compliance with San Joaquin Valley Air Pollution Control District fugitive dust suppression regulations~~ to further reduce emissions, during construction, of particulate matter that is 10 microns or less and 2.5 microns or less in diameter~~. The Fugitive Dust Control Plan shall include:

a. Name(s), address(es), and phone number(s) of person(s) responsible for the preparation, submission, and implementation of the plan.

b. Description and location of operation(s).

c. Listing of all fugitive dust emissions sources included in the operation.

d. The following dust control measures shall be implemented:

1. All onsite unpaved roads shall be effectively stabilized using water or chemical soil stabilizers that can be determined to be as efficient as or more efficient for fugitive dust control than California Air Resources Board approved soil stabilizers, and that shall not increase any other environmental impacts including loss of vegetation.

2. All material excavated or graded will be ~~sufficiently~~ watered to prevent excessive dust. Watering will occur as needed with complete coverage of disturbed areas. The excavated soil piles will be watered as needed to limit

dust emissions to less than 20% opacity or covered with temporary coverings.

3. Construction activities that occur on unpaved surfaces will be discontinued during windy conditions when winds exceed 25 miles per hour and those activities cause visible dust plumes that exceed the SJVAPCD 20% opacity standard. ~~Construction activities may continue if dust suppression measures are used to minimize visible dust plumes.~~
4. Track-out debris onto public paved roads shall not extend 50 feet or more from an active operation and track-out shall be removed or isolated such as behind a locked gate at the conclusion of each workday, except on agricultural fields where speeds are limited to 15 mph.
5. All hauling materials should be moist while being loaded into dump trucks.
6. All haul trucks hauling soil, sand, and other loose materials on public roads shall be covered (e.g., with tarps or other enclosures that would reduce fugitive dust emissions).
7. Soil loads should be kept below 6 inches or the freeboard of the truck.
8. Drop heights ~~should be minimized~~ when loaders dump soil into trucks shall not exceed 5 feet above the truck.
9. Gate seals should be tight on dump trucks.
10. Traffic speeds on unpaved roads shall be limited to 25 miles per hour.
11. All grading activities shall be suspended when visible dust emissions exceed 20%.
12. Other fugitive dust control measures as necessary to comply with San Joaquin Valley Air Pollution Control District Rules and Regulations.
13. Disturbed areas ~~should be minimized~~ shall not exceed those shown on the Site Plan.
14. Disturbed areas should be re-vegetated as soon as possible after disturbance if area is no longer needed for oil and gas activities.

Mitigation Measures

MM 4.3-1 Consistent with the requirements of the San Joaquin Valley Air Pollution Control District Regulation II-Permits, the Applicant shall obtain an Authority to Construct permit and a Permit to Operate for any facility or equipment requiring a permit from the San Joaquin Valley Air Pollution Control District, such as stationary sources required to obtain permits pursuant to District Rule 2010. All emissions increases from permitted equipment shall comply with District Rule 2201.

MM 4.3-2 The Applicant shall develop and implement a Fugitive Dust Control Plan in compliance with San Joaquin Valley Air Pollution Control District fugitive dust suppression regulations. The Fugitive Dust Control Plan shall include:

a. Name(s), address(es), and phone number(s) of person(s) responsible for the preparation, submission, and implementation of the plan.

b. Description and location of operation(s).

c. Listing of all fugitive dust emissions sources included in the operation.

d. The following dust control measures shall be implemented:

1. All onsite unpaved roads shall be effectively stabilized using water or chemical soil stabilizers that can be determined to be as efficient as or more efficient for fugitive dust control than California Air Resources Board approved soil stabilizers, and that shall not increase any other environmental impacts including loss of vegetation.
2. All material excavated or graded will be watered to prevent excessive dust. Watering will occur as needed with complete coverage of disturbed areas. The excavated soil piles will be watered as needed to limit dust emissions to less than 20% opacity or covered with temporary coverings.
3. Construction activities that occur on unpaved surfaces will be discontinued during windy conditions when winds exceed 25 miles per hour and those activities cause visible dust plumes that exceed the SJVAPCD 20% opacity standard.
4. Track-out debris onto public paved roads shall not extend 50 feet or more from an active operation and track-out shall be removed or isolated such as behind a locked gate at the conclusion of each workday, except on agricultural fields where speeds are limited to 15 mph.
5. All hauling materials should be moist while being loaded into dump trucks.
6. All haul trucks hauling soil, sand, and other loose materials on public roads shall be covered (e.g., with tarps or other enclosures that would reduce fugitive dust emissions).
7. Soil loads should be kept below 6 inches or the freeboard of the truck.
8. Drop heights when loaders dump soil into trucks shall not exceed 5 feet above the truck.
9. Gate seals should be tight on dump trucks.
10. Traffic speeds on unpaved roads shall be limited to 25 miles per hour.
11. All grading activities shall be suspended when visible dust emissions exceed 20%.

12. Other fugitive dust control measures as necessary to comply with San Joaquin Valley Air Pollution Control District Rules and Regulations.
13. Disturbed areas shall not exceed those shown on the Site Plan.
14. Disturbed areas should be re-vegetated as soon as possible after disturbance if area is no longer needed for oil and gas activities.

MM 4.3-3 All off-road construction diesel engines not registered under California Air Resources Board's Statewide Portable Equipment Registration Program, which have a rating of 50 horsepower or more, shall meet, at a minimum, the Tier 3 California Emission Standards for Off-road Compression-Ignition Engines as specified in California Code of Regulations, Title 13, section 2423(b)(1) unless that such engine is not available for a particular item of equipment. In the event a Tier 3 engine is not available for any off-road engine larger than 100 horsepower, that engine shall be equipped with retrofit controls that would provide nitrogen oxides and particulate matter emissions that are equivalent to Tier 3 engine.

a. All equipment shall be turned off when not in use. Engine idling of all equipment shall be limited to five minutes, except under exemptions specified in California Code of Regulations Title 13 Section 2449(d)(2)(A).
b. All equipment engines shall be maintained in good operating condition and in proper tune per manufacturers' specifications.

MM 4.3-4 To further reduce emissions of oxides of nitrogen from on-road heavy-duty diesel haul vehicles:

a. 2007 engines or pre-2007 engines shall comply with California Air Resources Board retrofit requirements set forth in California Code of Regulations Title 13 Section 2025.
b. All on-road construction vehicles, except those meeting the 2007/California Air Resources Board-certified Level 3 diesel emissions controls, shall meet all applicable California on-road emission standards and shall be licensed in the State of California. This does not apply to worker personal vehicles.
c. All on-road construction vehicles shall be properly tuned and maintained in accordance with the manufacturers' specifications.

Level of Significance After Mitigation

Impacts would be less than significant with mitigation.

Impact 4.3-2: Result in a Cumulatively Considerable Net Increase of Any Criteria Pollutant for Which the Project Region is Non-Attainment Under an Applicable Federal or State Ambient Air Quality Standard

The current nonattainment status of regional pollutants is determined by past development and present activities. The District's attainment plans are designed to ensure the future attainment of State and federal ambient air quality standards. Consequently, the District's application of thresholds of significance for emission of criteria pollutants determines whether a project's emissions would have a cumulatively considerable contribution of emissions of a criteria pollutant for which the District is non-attainment. If project emissions exceed the thresholds of significance for criteria pollutants the project would be expected to result in a considerable net increase of any criteria pollutant for which the District is in non-attainment under applicable federal or State ambient air quality standards. The SJV is in nonattainment for $PM_{2.5}$, PM_{10}, and ozone. Ozone is addressed by examining its precursors which are NO_X, VOC, and CO.

Per the SJVAPCD's March 2015 GAMAQI:

> "By its very nature, air pollution is largely a cumulative impact. The nonattainment status of regional pollutants is a result of past and present development. Future attainment of State and Federal ambient air quality standards is a function of successful implementation of the District's attainment plans. Consequently, the District's application of thresholds of significance for criteria pollutants is relevant to the determination of whether a project's individual emissions would have a cumulatively significant impact on air quality.
>
> A lead agency may determine that a project's incremental contribution to a cumulative effect is not cumulatively considerable if the project will comply with the requirements in a previously approved plan or mitigation program, including, but not limited to an air quality attainment or maintenance plan that provides specific requirements that will avoid or substantially lessen the cumulative problem within the geographic area in which the project is located [CCR §15064(h)(1)].
>
> Thus, if project specific emissions would be less than the thresholds of significance for criteria pollutants, as a general matter the project would not be expected to result in a cumulatively considerable net increase of any criteria pollutant for which the District is in non-attainment under applicable federal or State ambient air quality standards." (SJVAPCD 2015, Section 7.14.)

The SJVAPCD March 2015 Draft GAMAQI also states,

> As discussed in Section 8.3.1 (Basis for Air Quality Thresholds of Significance), the District's thresholds of significance for criteria pollutants are based on District rule 2201 (New Source Review) offset requirements. Furthermore, New Source Review (NSR) is a major component of the District's attainment strategy. NSR

> provides mechanisms, including emission trade-offs, by which Authorities to Construct such sources may be granted, without interfering with the attainment or maintenance of Ambient Air Quality Standards. District implementation of NSR ensures that there is no net increase in emissions above specified thresholds from new and modified Stationary Sources for all nonattainment pollutants and their precursors. In fact, permitted emissions above offset thresholds equivalent to the District's thresholds of significance for criteria pollutants are mitigated to below the thresholds, and the District's attainment plans show that this level of emissions increase will not interfere with attainment or maintenance of ambient air quality standards.
>
> The District's attainment plans demonstrate that project-specific net emissions increase below New Source Review (NSR) offset requirements will not prevent the District from achieving attainment. Consequently, emission impacts from sources permitted consistent with NSR requirements are not individually significant and are not cumulatively significant. (SJVAPCD 2015, Section 8.8.4.)

As stated above, to evaluate whether the oil and gas activities that would be authorized under the Project would result in a cumulatively considerable net increase of any criteria pollutant for which the District is nonattainment, the Kern County CEQA checklist uses SJVAPCD thresholds of:

Operational and Area/Construction Sources	Reactive organic gases (ROG)	10 tons per year
	Oxides of nitrogen (NO_X)	10 tons per year
	Particulate matter (PM_{10})	15 tons per year
Stationary Sources (as Determined by District Rules)	Severe nonattainment	25 tons per year
	Extreme nonattainment	10 tons per year

If the levels of ROG, NO_X or PM_{10} are exceeded, then Project generated emissions would be considered to have a cumulatively considerable net increase. However, since the SJV is in nonattainment also for $PM_{2.5}$ and ozone, then levels of CO and $PM_{2.5}$ will be evaluated against the SJVAPCD Criteria Pollutant thresholds listed in Table 4.3-10.

Table 4.3-10: San Joaquin Valley Air Pollution Control District Criteria Pollutant Emissions Significance Thresholds (tons per year)

Pollutant/ Precursor	Construction Emissions	Operational Emissions	
		Permitted Sources and Activities	**Non-Permitted Sources and Activities**
ROG	10	10	10
NO_X	10	10	10
PM_{10}	15	15	15

Table 4.3-10: San Joaquin Valley Air Pollution Control District Criteria Pollutant Emissions Significance Thresholds (tons per year)

Pollutant/ Precursor	Construction Emissions	Operational Emissions	
		Permitted Sources and Activities	Non-Permitted Sources and Activities
$PM_{2.5}$	15	15	15
CO	100	100	100
SO_X	27	27	27

Source: SJVAPCD n.d.(b), Section 8.3.
Key:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SO_XS = sulfur oxides

The thresholds of significance for ROG, NO_X and PM_{10} presented in Table 4.3-10 are equivalent to the Kern County CEQA Implementation Document and Kern County Environmental Checklist standards listed above; the table also provides standards for criteria pollutants such as $PM_{2.5}$, CO, and SO_X, which were not listed among the Kern County CEQA Implementation Document and Kern County Environmental Checklist standards. Therefore, emissions generated by the Project were evaluated against the SJVAPCD Air Quality Thresholds of Significance for Criteria Pollutants. For this analysis, if these thresholds are exceeded then the Project would be considered to have significant impacts.

Source data and emissions associated with the Project were determined based on the Air Quality Technical Report prepared by Vector Environmental, Inc. (Vector). Air quality impacts associated with the Project are separated by construction and operational emissions. The emissions tables derived from the data provided by Vector are presented in Appendix I of the 2015 FEIR (SREIR Volume 4).

The air analysis conducted by Vector to support this evaluation uses a baseline level of 43,028 wells that were operating in 2012 and an assumed number of 82,136 wells operating in 2035. The assumed number of new wells constructed spans from 3,966 in 2015 to 4,083 in 2035. The number of wells projected to be built every year exceeds the number of wells that are projected to be authorized under this Project and therefore these estimates are considered conservative. Kern County does not anticipate authorizing more than 3,647 new well permits in a single year. Therefore, the final total emissions from the Project will be calculated by scaling down the emissions calculated using the assumed number of new wells to the emissions corresponding to the authorized number of new wells per year, that is 3,647 wells each year (Table 4.3-32, below).

Construction Emissions

To estimate emissions associated with construction activities associated with the proposed Project, each activity was estimated separately for:

- Construction of new facilities for crude oil and natural gas production and processing, such as crude oil dehydration facilities and new steam generator plants;
- Construction of permit exempt equipment and small production settings; and
- Construction activity related to wells.

Table 4.3-11 provides the data sources and assumptions used to estimated construction emissions. A list of equipment used during construction is presented as Appendix K of the 2015 FEIR (SREIR Volume 4).

Table 4.3-11: Data Sources and Assumptions for the Construction Air Impact Analysis

Activity	**Data Source/Assumption**
Construction of Permitted Equipment (New Facilities)	
Baseline	The number of emission units constructed during the baseline year (2012) was determined from the number of SJVAPCD Authority to Construct permits for new equipment converted to equipment Permits to Operate.
Future activities	To determine the number of new units expected to be required for the 2035 Project build-out, the change in needed capacity was determined by assuming that the capacity will grow at the same rate as the number of active wells. Project equipment needed for 2035 was forecast using the difference between the number of active wells in 2012 and the number of active wells forecast for 2035. The number of additional units for each equipment category was determined by dividing the change in capacity by the average capacity of the equipment.
Emission Factors	Emission factors for on-road mobile sources were derived using EMFAC2011. The model was used to generate Kern County fleet average emission factors by vehicle weight class and year. Emission factors for off-road mobile sources and portable equipment were derived using OFFROAD2011. The model was used to generate fleet average emission factors for the off-road mobile source and portable equipment fleet located in the San Joaquin Valley. Factors were generated by equipment type, horsepower category and fuel type for 2012 and annually for the period 2015 through 2035.
Required Equipment and Timing	For oilfield facilities, the time required to complete construction usually depends on the number of new emission units to be installed and the size of the emission units. When detailed construction information was lacking, the type of equipment to be built and the Project acreage was used to generate lists of equipment and activities likely required for the construction Project.
Vehicle Trips	Using the available data, the number of vehicle trips required for the construction of a given type of facility (emission unit) were determined for each source category (i.e., tanks, boilers, engines).

Table 4.3-11: Data Sources and Assumptions for the Construction Air Impact Analysis

Activity	**Data Source/Assumption**
Average Trip Length	The offsite travel distance per vehicle trip was calculated as the average travel distance to the oil and gas planning zone (Subarea). The onsite travel distance per vehicle trip was calculated as the average onsite distance between facilities.
Fugitive Dust	Fugitive dust emissions were calculated using EPA predictive emission factor equations (EPA AP42, Chapter-13).
Construction Related to Wells	
Baseline	The number of wells constructed, reworked, and abandoned in the baseline year 2012 were determined from preliminary well counts provided by the CalGEM Distict-4 Office. The number of wells that underwent hydraulic stimulation during 2012 was determined from records obtained from “Frac-Focus.”
New Well Activities	The information used for evaluating well construction activities was obtained from detailed records compiled during the construction of ten new oil and gas production wells in 2010 and 2011. Detailed activity lists of the on-road mobile sources, off-road mobile sources, and portable equipment used for each construction phase were maintained. The data were compiled during the construction of wells having an average depth of about 10,000 feet. Consequently, to use data for evaluating activities which depend on well depth (such as drilling) the data was adjusted to enable its use for evaluating activities required for construction of wells having other depths.
On-road and Off-road Sources	The list of the on-road mobile sources, off-road mobile sources, and portable equipment used for each construction phase was obtained from the records compiled during the construction of 10 new oil and gas production wells, having an average depth of about 10,000 feet, in 2010 and 2011. On-road activities for construction include worker commute and delivery of equipment and materials. Off-road activities for construction include site preparation, pre-drilling survey, drilling, completion, stimulation, installation of flow lines, installation of pumping unit, installation of electrical systems, well rework, and well abandonment.
Well Stimulation	Hydraulic stimulation information was derived from data obtained from CalGEM, EPA publications, and fundamental engineering principles. Four categories of well depths were evaluated, namely 5,000, 10,000, 15,000, and 20,000 feet and greater. Each well was evaluated according to its depth. The activity predicted for hydraulic stimulation includes the vehicles and equipment required. The number of vehicles primarily depends on the surface injection pressure, mass of proppant and injection volumes. The equipment likely to be used for the stimulation job was determined based on the wells that underwent hydraulic stimulation during the baseline year. Each well completed in future years was assumed to undergo initial hydraulic stimulation. Emissions from stimulation jobs conducted during rework should be added to the emissions predicted for rework. Emissions were calculated using the OFFROAD2011 fleet average emission factors.
Decommissioning Emissions	Well abandonment involves plugging by placing cement in the well-bore or casing at certain specified intervals. The capacity of a rig used for plugging and abandonment was assumed to be comparable to those used for drilling and completions. Since historic information on the equipment used for well abandonment was not available, the vehicle and equipment list used for routine well maintenance was used for calculating emissions from well abandonment. Emissions were calculated using the OFFROAD2011 fleet average emission factors.

Table 4.3-11: Data Sources and Assumptions for the Construction Air Impact Analysis

Activity	Data Source/Assumption
Engines	The horsepower required for both the hoist system and the mud circulation system depends on the depth of the rig. For the activities of well drilling, well completions, and well rework, the number and average horsepower rating of the engines used by the rig hoist and mud circulation systems were estimated from the data reported by the drilling industry for the 2012 U.S. fleet. Engine type and horsepower for well abandonment was determined from information provided by a manufacturer of these types of rigs and provide of well pulling services ("Stewart and Stevens").
Ancillary Equipment	Ancillary equipment may include diesel engines to power the mud filtration system, small generator sets to power utility systems and other miscellaneous equipment, and off-road mobile sources such as cranes for setting up the rig structure and mast. The list of ancillary equipment included in the drilling operation was obtained from the construction records of 10 wells in 2010 and 2011.
Duration	The number of days required to complete drilling, completion, rework, and abandonments depends on the well depth, and was estimated by interpolating data reported in CalGEM well records. Durations of other tasks required for completing a specific phase of a construction activity were obtained from the records of the construction of 10 wells in 2010 and 2011.

Key:
CalGEM = California Geologic Energy Management Division
EPA = U.S. Environmental Protection Agency
SJVAPCD = San Joaquin Valley Air Pollution Control District

Construction of New Facilities

As the number of active wells increases over time more substantial construction activities, such as those required for building new emission units, may be required. New facilities that could be constructed under this Project include crude oil and natural gas production and processing plants, such as crude oil dehydration facilities and new steam generator plants. Equipment that was assumed would be built included boilers, process heaters, internal combustion engines, steam generators, production tanks, and flaring facilities.

The number of emission units constructed during the baseline year (2012) was determined from the number of SJVAPCD ATC permits for new equipment converted to PTOs during the year. Facility construction activity occurring during 2012 was determined from a list of equipment provided by the SJVAPCD. The equipment is listed in Table-4.3-11a.

To determine the number of new units expected to be required for the 2035 Project build-out, the change in needed capacity was determined by assuming that capacity will grow at the same rate as the number of active wells. The number of new emission units required to provide additional processing capacity for the change in the number of active wells from 2012 to 2035 was calculated for each source category (e.g., tanks, boilers, and engines) as follows. First, the total processing capacity of the equipment included in each source category was determined from the 2012 annual emission inventory for Title V oil and gas production sources which was obtained from the SJVAPCD. The

Title V operators account for approximately 90% of the active crude oil wells in Kern County. To account for smaller non-Title V producers, the capacity was increased by 10%.

The increased processing capacity required for Project build-out was then determined by prorating the baseline processing capacity using the ratio of the change in active well counts between 2012 and 2035. The average capacity of the baseline equipment included in each source category was then determined. Finally, the number of new emission units within a given source category required for Project build-out was determined by dividing the change in processing capacity (2012 to 2035) for each source category by the average capacity of the baseline equipment.

Table 4.3-11a: Baseline Equipment Constructed in Kern County during 2012

Permitted Equipment	Total Acreage		Capacity		Count
			Rating	Units	
Boilers	<0.01	(0.01)	10	MMBtu/hr	0.1
Cogeneration	0.20	(0.50)	33	MW	0.4
Process Heaters	<0.01	(0.01)	8	MMBtu/hr	0.4
IC Engines	0.02	(0.01)	671	BHP*hr	1.5
Steam Generators	0.27	(0.08)	65	MMBtu/hr	2.4
Tanks Settings	0.15	(0.04)	3,400	bbl Capacity	3.7
TEOR Systems	0.25	(0.50)	74	System	0.5
VOCDD (Flare)	0.05	(0.01)	346	MMBtu/hr	0.5

Notes:
Acreage numbers in parenthesis are estimates of the footprint (acres) per emission unit. Estimates include the area required for access of equipment.
Key:
bbl = barrel
BHP*hr = Brake Horsepower Hour
IC = internal combustion
MMBtu/hr = million metric British thermal units per hour
MW = megawatt
TEOR = thermally enhanced oil recovery
VOCDD = volatile organic compound destruction devices

The results of the forecasts for new emissions units are summarized in Table-4.3-11b.

Table-4.3-11b: Forecast of Additional Equipment Needed for 2035 Project Build-Out

Permitted Equipment	Kern County Baseline		Required Acreage for New Systems	Count			
	Total Capacity	Units		Kern County	Western Subarea	Central Subarea	Eastern Subarea
Boilers	111	MMBtu/hr	0.05	5	3	0	2
Cogeneration	1,860	MW	19.96	49	18	0	31
Process Heaters	607	MMBtu/hr	0.22	39	23	15	1
IC Engines	217,314	BHP*hr	1.06	93	77	0	16
Steam Generators	34,655	MMBtu/hr	27.33	238	157	0	81
Production Tanks	2,720,948	Bbl Capacity	21.10	368	155	24	189
TEOR Systems	27,723	System	0.26	70	18	0	52
VOCDD (Flare)	41,414	MMBtu/hr	1.49	36	14	11	11

Key:
bbl = barrel
BHP*hr = Brake Horsepower Hour
IC = internal combustion
MMBtu/hr = million metric British thermal units per hour
MW = megawatt
TEOR = thermally enhanced oil recovery
VOCDD = volatile organic compound destruction devices

Equipment assumed to be used during construction of new facilities includes graders, tractors/loaders/backhoes, concrete/industrial saws, rubber-tired bulldozers, cranes, forklifts, cement and mortar mixers, pavers, rollers, and air compressors. Emissions estimates were calculated based on the usage hours, horse powers, and load factors of the equipment required to perform site preparation, grading, building construction, paving, and architectural coating.

Emissions from vehicle trips for construction activity were calculated by determining the number of vehicle trips required for construction of each source category (e.g., tanks, boilers, and engines) as determined by the tasks to be completed for installation of new emissions units and the time to complete those tasks, as described above. The average travel distance to each subarea was used to estimate the offsite travel distance per vehicle trip. The average onsite distance between facilities was used to calculate onsite travel distance per vehicle trip. The trip distances per subarea are listed in Table 4.3-11c.

Table 4.3-11c: Trip Distances for Assessing On-road Vehicle Miles Traveled for Construction

Activity	Western Subarea	Central Subarea	Eastern Subarea
Offsite Travel[a]	42.74	20.11	13.87
Onsite Travel[b]	0.21	1.15	0.40

Notes:
[a] Average distance from the intersection of Coffee Road and Rosedale Highway to the wells contained with the planning zone.
[b] The average distance is estimated by dividing the total onsite distance required to travel to the equipment (permit-units) locations divided by the total number of permit units. Travel on unpaved roads accounts for 90% of the total onsite travel.

The analysis of emissions generated in the construction of new facilities takes into account baseline and future activities. On-road and off-road emission factors associated with construction were estimated using two models: EMFAC2011 for on-road emission factors and OFFROAD2011 for off-road emission factors. Total emissions were calculated using the CalEEMod model.

Total emissions resulting from the construction of new facility equipment during a Project year (i.e., any year between 2015 and 2035), and the construction of facilities over the Project period (2015 to 2035) are summarized in Tables 4.3-12 and 4.3-13. These tables show the type of equipment that would be built, the annual average number of new equipment that would be built, the total (on-road, off-road, and all portable equipment) emissions generated by the construction of the equipment, and the SJVAPCD construction emissions thresholds. *Though Tables 4.3-11a and 4.3-11b include estimates of potential cogeneration capacity needed for Project buildout, emissions from constructing new or expanding existing cogeneration units are not included in Table 4.3-12, as new cogeneration facilities are not expected to be developed as part of the Project due to Kern County's already substantial cogeneration capacity and available megawatts of renewable wind and solar energy.*

Table 4.3-12: Kern County Facility Construction Emissions during a Single Year (tons/year)

Equipment to be Built	Average Number of Equipment to be Built Annually	ROG	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$
Boiler	0.3	0.5	4.4	2.6	0.0	0.3	0.3
Process Heater	2.0	4.0	31.7	18.8	0.0	2.3	2.1
Internal Combustion Engine	4.9	8.0	75.2	44.7	0.1	5.5	4.9
Steam Generators	12.5	22.5	193.3	116.2	0.2	14.3	12.6
Production Tanks	19.3	37.4	298.8	178.5	0.2	21.9	19.5
VOCDD (Flare)	1.9	3.7	29.5	17.6	0.0	2.2	1.9
	TOTAL	**76**	**633**	**378**	**0.5**	**46.5**	**41.2**

Table 4.3-12: Kern County Facility Construction Emissions during a Single Year (tons/year)

Equipment to be Built	Average Number of Equipment to be Built Annually	ROG	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$
SJVAPCD Construction Emissions Threshold		10	10	100	27	15	15

Key:
CO = carbon monoxide\
IC = internal combustion
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SJVAPCD = San Joaquin Valley Air Pollution Control District
SO_2 = sulfur dioxide
VOCDD = volatile organic compound destruction devices

Table 4.3-13: Total Kern County Facility Construction Emissions over the Project Period (2015 – 2035) (Tons/Year)

Equipment to be Built	Number of Equipment to be Built	ROG	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$
Boiler	6	9.7	92.00	54.1	0.1	6.6	6
Process Heater	43	83.1	665.70	394.40	0.5	48.2	43.2
Internal Combustion Engine	102	168.80	1,579.30	937.70	1.3	114.80	102.70
Steam Generators	262	471.60	4,060.30	2,439.30	3.4	300.40	265.10
Production Tanks	405	784.70	6,273.90	3,748.20	5.2	460.10	408.70
VOCDD (Flare)	40	77.5	619.60	370.30	0.5	45.5	40.4
TOTAL		**1,595.40**	**13,290.80**	**7,944.00**	**11.00**	**975.60**	**866.10**

Key:
CO = carbon monoxide
IC = internal combustion
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SO_2 = sulfur dioxide
VOCDD = volatile organic compound destruction devices

Total Project emissions resulting from the construction of new facilities on an annual basis would exceed the SJVAPCD Criteria Pollutant Emissions Significance Thresholds except for SO_2. However, constructing of new facilities would be subjected to the District's air permitting process

(Rule 2201), which would ensure that all emissions would have to be fully offset. Therefore, there would be no net increase in these emissions.

Construction of Permit Exempt Equipment and Small Production Settings

Permit-exempt equipment and small production settings consist mainly of pressure vessels and piping components, and typically occupy less than 0.50 acre. Future production activities would entail the construction of these types of small production settings. The new equipment would have a small footprint and would require simple construction activity. Small production settings would be constructed on an as-needed basis over time and would be distributed throughout the oilfield. No information is available on the number and location of permit-exempt equipment and small production settings that would be constructed or installed during the Project years 2015 to 2035. Due lack of data and because missions from construction of permit exempt equipment and small production settings are known to be small in quantity, they were assumed to be equivalent to be 5% of the construction emissions for permitted equipment.

Total estimated emissions resulting from the construction of new Permit Exempt Equipment and Small Production Settings during a Project year (i.e., any year between 2015 and 2035) are summarized in Table 4.3-14.

Table 4.3-14: Total Estimated Emissions from Construction of Permit Exempt Equipment and Small Production Settings

	Emissions (tons per year)					
	ROG	**NO_X**	**CO**	**SO_2**	**PM_{10}**	**$PM_{2.5}$**
TOTAL	**4**	**32**	**19**	**0.03**	**2**	**2**
SJVAPCD Construction Emissions Threshold	10	10	100	27	15	15

Key:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SJVAPCD = San Joaquin Valley Air Pollution Control District
SO_2 = sulfur dioxide

This emissions listed in Table 4.3-14 indicate that the emissions of all criteria pollutants except SO_2 associated with construction activities related to Permit Exempt Equipment and Small Production Settings would exceed the SJVAPCD Construction Emissions Threshold. These types of construction activities do not require air permits and, therefore, these emissions would not be offset.

Construction Related to Wells

The construction activities related to wells include well drilling, rework of wells, well stimulation and well abandonment. The emissions of criteria pollutants associated with each of these activities are presented in Tables 4.3-15 through 4.3-18. As discussed above, the air analysis used the baseline level of wells that were operating in 2012 and an assumed number of wells of 82,136 operating in 2035. The number of new wells projected to be built in 2035 (4,083) exceeds the number of wells that are projected to be authorized under this Project and, therefore, these estimates are considered conservative. This SREIR will not authorize Kern County permitting any more than 3,647 new well permits in a single year. The total emissions will be adjusted (Table 4.3-32, below) to account for the smaller number of wells authorized, compared to the number of wells used in the calculations.

The well count numbers for drilling, rework, well stimulation, and well abandonment for the baseline year 2012 were determined using preliminary information obtained from the California Geologic Energy Management Division (CalGEM) District-4 Field Office. The petroleum industry provided projected well counts during the Project period 2015 through 2035.

Table 4.3-15: Estimated Annual Emissions Associated with Drilling of Wells in 2012 and 2035

Year	Subarea	Well Count	Criteria Emissions (tons per year)						Emission Factors (lbs. per year per well)					
			NO_X	VOC	CO	SO_X	PM_{10}	$PM_{2.5}$	NO_X	VOC	CO	SO_X	PM_{10}	$PM_{2.5}$
2012	Western	2,549	6,345.35	1,067.97	4,369.40	6.25	381.34	248.92	4,978.70	837.95	3,428.32	4.90	299.21	195.31
	Central	47	468.30	155.63	357.55	0.43	24.54	16.01	19,927.84	6,622.71	15,215.01	18.43	1,044.06	681.29
	Eastern	796	1,563.05	103.48	1,133.80	1.45	99.63	63.65	3,927.25	260.00	2,848.73	3.63	250.33	159.93
	TOTALS	3,392	8,376.70	1,327.09	5,860.75	8.13	505.51	328.58	4,939.09	782.48	3,455.63	4.79	298.06	193.74
2035	Western	2,623	1,892.96	893.33	4,230.87	6.39	187.63	67.74	1,443.35	681.15	3,225.98	4.87	143.06	51.65
	Central	140	688.08	430.83	1,049.56	1.28	39.20	16.54	9,829.75	6,154.74	14,993.78	18.31	559.97	236.25
	Eastern	1,320	656.10	86.90	1,827.40	2.38	78.43	25.70	994.09	131.66	2,768.78	3.61	118.83	38.94
	TOTALS	4,083	3,237.14	1,411.06	7,107.84	10.05	305.25	109.98	1,585.67	691.19	3,481.67	4.92	149.52	53.87

Key:
CO = carbon monoxide
lbs = pounds
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SO_X = sulfur oxides

Table 4.3-16: Estimated Annual Emissions Associated with Rework of Wells in 2012 and 2035

Year	Subarea	Well Count	Criteria Emissions (tons per year)						Emission Factors (lbs. per year per well)					
			NO_X	VOC	CO	SO_X	PM_{10}	$PM_{2.5}$	NO_X	VOC	CO	SO_X	PM_{10}	$PM_{2.5}$
2012	Western	1,298	904.23	52.35	564.67	0.89	54.26	37.57	1,393.26	80.66	870.07	1.36	83.61	57.88
	Central	33	87.48	4.25	66.02	0.08	4.77	3.02	5,301.78	257.75	4,001.07	4.88	289.05	182.85
	Eastern	613	268.97	16.02	177.43	0.24	17.75	11.67	877.55	52.25	578.89	0.79	57.90	38.06
	TOTALS	1,944	1,260.67	72.62	808.12	1.21	76.78	52.25	1,296.99	74.71	831.40	1.24	78.99	53.76
2035	Western	1,880	377.17	31.03	760.01	1.29	33.96	13.35	401.24	33.01	808.53	1.37	36.13	14.20
	Central	107	140.44	7.54	212.89	0.26	8.56	3.43	2,624.97	141.03	3,979.25	4.91	159.94	64.07
	Eastern	1,890	223.52	20.34	530.46	0.75	24.69	8.35	236.53	21.53	561.34	0.80	26.12	8.83
	TOTALS	3,877	741.13	58.91	1,503.37	2.30	67.21	25.13	382.32	30.39	775.53	1.19	34.67	12.96

Key:
CO = carbon monoxide
lbs. = pounds
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SO_X = sulfur oxides

Table 4.3-17: Estimated Annual Emissions Associated with Well Stimulation in 2012 and 2035

Year	Subarea	Well Count	Criteria Emissions (tons per year)						Emission Factors (lbs. per year per well)					
			NO_X	VOC	CO	SO_X	PM_{10}	$PM_{2.5}$	NO_X	VOC	CO	SO_X	PM_{10}	$PM_{2.5}$
2012	Western	414	69.44	3.48	37.89	0.09	15.46	3.61	335.44	16.82	183.06	0.43	74.68	17.46
	Central	28	4.21	0.18	3.10	0.01	0.95	0.20	300.87	12.88	221.33	0.37	67.96	14.58
	Eastern	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	TOTALS	442	73.65	3.66	40.99	0.09	16.41	3.82	333.25	16.57	185.49	0.43	74.26	17.28
2035	Western	1,233	62.19	4.38	88.71	0.27	40.24	5.43	100.87	7.10	143.89	0.43	65.27	8.80
	Central	171	10.59	0.59	17.40	0.03	5.18	0.67	123.83	6.84	203.49	0.37	60.61	7.81
	Eastern	41	1.58	0.10	2.68	0.00	0.27	0.05	77.08	4.73	130.62	0.24	13.30	2.45
	TOTALS	1,445	74.35	5.06	108.79	0.30	45.70	6.14	102.91	7.00	150.57	0.42	63.25	8.50

Table 4.3-18: Estimated Annual Emissions Associated with Well Abandonment in 2012 and 2035

Year	Subarea	Well Count	Criteria Emissions (tons per year)						Emission Factors (lbs. per year per well)					
			NO_X	VOC	CO	SO_X	PM_{10}	$PM_{2.5}$	NO_X	VOC	CO	SO_X	PM_{10}	$PM_{2.5}$
2012	Western	1,880	279.79	25.90	194.51	0.24	22.07	17.54	297.65	27.55	206.92	0.25	23.48	18.66
	Central	9	1.81	0.17	1.29	0.00	0.20	0.12	402.39	37.16	285.81	0.35	44.91	26.07
	Eastern	215	30.62	2.83	21.25	0.03	2.40	1.92	284.80	26.31	197.68	0.24	22.31	17.84
	TOTALS	2,104	312.22	28.90	217.04	0.26	24.67	19.58	296.79	27.47	206.32	0.25	23.45	18.61
2035	Western	2,534	98.10	9.52	259.95	0.32	7.70	3.37	77.43	7.52	205.17	0.25	6.08	2.66
	Central	126	6.92	0.66	17.68	0.02	1.40	0.33	109.78	10.48	280.67	0.35	22.22	5.19
	Eastern	1,040	38.54	3.74	101.59	0.13	2.95	1.32	74.11	7.19	195.36	0.24	5.67	2.54
	TOTALS	3,700	143.56	13.92	379.22	0.47	12.05	5.01	77.60	7.52	204.98	0.25	6.51	2.71

Key:
CO = carbon monoxide
lbs = pounds
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SO_X = sulfur oxides

Table 4.3-19 presents the total of all annual construction-related emissions.

Table 4.3-19: Total Annual Estimated Emissions from Well Construction

Year	Subarea	Criteria Emissions (tons per year)					
		NO_X	VOC	CO	SO_X	PM_{10}	$PM_{2.5}$
2012	Western	7,598.80	1,149.70	5,166.48	7.46	473.13	307.64
	Central	561.81	160.23	427.96	0.52	30.46	19.35
	Eastern	1,862.63	122.33	1,332.48	1.71	119.78	77.24
	TOTALS	**10,023.24**	**1,432.26**	**6,926.91**	**9.70**	**623.37**	**404.22**
2035	Western	2,446.44	939.60	5,387.69	8.32	269.95	90.27
	Central	846.88	439.69	1,300.10	1.60	54.36	20.98
	Eastern	927.81	111.75	2,486.35	3.30	106.54	35.61
	TOTALS	**4,221.13**	**1,491.05**	**9,174.14**	**13.22**	**430.85**	**146.85**
SJVAPCD Construction Emissions Threshold		10	10	100	27	15	15

Key:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
SJVAPCD = San Joaquin Valley Air Pollution Control District
SO_X = sulfur oxides
VOC = volatile organic compound

Tables 4.3-15 through 4.3-19 indicate that the emissions associated with well construction activities would exceed the SJVAPCD Construction Emissions Threshold. Since the SJV Project region is nonattainment for PM_{10}, $PM_{2.5}$, and ozone, well construction-related criteria pollutant emissions would result in considerable net increase of the criteria pollutants NO_X, VOC, CO, PM_{10} and $PM_{2.5}$, and would have significant impact. Well construction activities do not require air permits and, therefore, these emissions would not be offset.

Summary of Construction Emissions

In summary, emissions from the new facility and well construction at a Project level would result in emissions levels that would exceed SJVAPCD Construction Emissions Threshold. Only the operational emissions from equipment subject to SJVAPCD Rule 2201 (New Source Review) that exceeds the SJVPACD's offset thresholds would be required to be offset because it would be a condition of the SJVAPCD air permit. Although permitted stationary source operational emissions that are above the SJVAPCD's thresholds of significance would be offset through SJVAPCD Rule 2201 (New Source Review), other equipment and activities are exempt. Specifically, SJVAPCD rules do not require offsets for construction and operational emissions from equipment subject to portable equipment registrations or permit-exempt equipment registrations. In addition, new facility construction and well construction emissions have no offset requirements. Since these emissions exceed the SJVAPCD Construction Emissions Threshold and would not be offset, they would result in a cumulatively considerable net increase of criteria pollutants for which the Project region is nonattainment and, therefore, the construction impacts would be significant.

Operational Emissions

Operational emissions sources include emissions from oil and gas production facilities that are stationary permitted sources, emissions from permit-exempt sources, such as small pumps and generators, and emissions from mobile sources, such as vehicles. The analysis that follows is consistent with the recommendations of the SJVAPCD's March 2015 Guidance for Assessing and Mitigating Air Quality Impacts that operational criteria pollutant emissions associated with permitted sources and activities be evaluated separately from non-permitted sources and activities (SJVAPCD 2015, Section 8.3.3).

Permitted Stationary Equipment

Oil and gas activities that would be authorized under the Project would result in the operations of several types of stationary permitted emission sources, such as boilers, cogeneration plants, process heaters, reciprocating internal combustion engines, steam generators, production tanks, thermally enhanced oil recovery wells, and VOCDD (flares). The SJVAPCD air permit program requires the application of District Rule 2201 (New Source Review)), which mandates that new permitted stationary equipment include best available control technology and that all criteria pollutant emissions be offset to below thresholds of significance established by the District. *As explained above, while CARB recently performed an audit of the SJVAPCD ERC Banking Program, which highlighted some potential issues with the program, CARB did not overturn the program (CARB 2020b, 2020c). Subsequently, the SJVAPCD Board approved staff recommendations to remove Ag-ICE projects from the NOx ERC equivalency system and to remove orphan shutdown projects from the VOC ERC equivalency system, effective September 17, 2020 (SJVAPCD 2020). This action means that the SJVAPCD cannot demonstrate federal equivalency with the surplus value test for NOx and VOC and thus any new major source or federal major modification triggering NOx or VOC offsets under Rule 2201 will require "surplus at time of use" ERCs, which means ERCs are demonstrated to be surplus at the time an ATC is issued rather than at the time that the emission reductions began. This process will remain in place until such time that equivalency with the federal program is again demonstrated by the SJVAPCD. This step by the SJVAPCD thus restricts the allowable number of ERCs that are valid for use as offsets in the Valley, but does not change the way that ERCs are used nor does it change permitting requirements under Rule 2201. Thus, permitted stationary sources will only be allowed to move forward and be permitted by the SJVPACD if emissions are properly offset and if the SJVPACD approves an ATC, as required by Rule 2201.* Best available control technology represents the most stringent control technique or limitation that has been achieved in current technology for the same class of source. In addition, more effective control technique must be used where possible. Emissions offsets may be provided by emissions reductions, or may be obtained by purchasing emissions reduction credits from another party. Therefore, the net impact of offsetting is a reduction of emission at the regional scale.

For the evaluation of emissions that would be generated from this Project, emissions from permitted stationary equipment used for crude oil and natural gas production in Kern County were determined from the 2012 emission inventories obtained from the Air District for oil and gas production companies subject to Title V permit requirements (see Table 4.3-20). The permitted emission sources evaluated in this analysis includes the following:

- Boiler;
- Process Heater;
- Internal Combustion Engine;
- Steam Generators;
- Production Tanks;
- Thermally Enhanced Oil Recovery (TEOR) Wells;
- VOCDD (Flare);
- Fugitive $PM_{10;}$ and
- Fugitive VOC.

Since the Title V oil and gas production sources account for approximately 90% of the active wells in the County and more than 95% of the total oil production in the County, it was assumed that they also account for 90% to 95% of the emissions from equipment used by the oil and gas sector. To account for the remaining emissions from small oil and gas operators, not subject to Title V permit requirements, emissions were increased by 10%.

The increase in capacity required for future production was assumed to be proportional to the increase in the number of active wells. The number of new emission units was estimated from the change in capacity and the average size of the emission unit.

Project emissions would exceed the SJVAPCD Operational Emissions and, therefore, would represent a potentially significant impact. The annual contribution of PM_{10} and $PM_{2.5}$ would be almost 30 times the threshold. The emissions of ozone precursors (NO_X, ROG, and CO) would exceed their respective thresholds: NO_X would be almost 50 times the threshold, VOC more than 170 times the threshold, and CO more than eight times the threshold. However, all emissions increases from permitted equipment plus the 10% allowance from non-permitted equipment would be required to be fully offset pursuant to District Rule 2201. Offsets for emissions of NO_X and VOC would be required at a ratio of 1 to 1.5. Other criteria pollutants are assumed to be offset at a ratio of 1 to 1. Therefore, there would be no net increase in these emissions.

Table 4.3-20: Estimated Change in Operational Emissions For Stationary Source Equipment

Chang in Equip. Emissions	Change in Capacity	Capacity Units	Kern County Change in Emissions from Stationary Source Equipment					
			NO_X TPY	VOC TPY	CO TPY	SO_X TPY	PM_{10} TPY	$PM_{2.5}$ TPY
Boiler	45	MMBtu/hr	0.73	0.08	0.13	0.00	0.16	0.16
Cogeneration	1,583	MW	535.37	130.84	747.84	50.38	148.10	148.10
Fugitive Emissions	26,101	Wells	0.00	128.61	0.00	0.00	2.76	2.76
Process Heater	211	MMBtu/hr	2.71	0.49	0.82	0.11	0.78	0.78
IC Engine ()	77,956	BHP*hr	114.10	32.91	480.16	0.08	1.13	1.13
Steam Generators	15,489	MMBtu/hr	234.79	108.68	97.72	94.51	271.87	271.87
Production Tanks	1,604,898	bbl Capacity	0.74	327.60	4.05	1.33	0.08	0.08
TEOR Wells	19,061	TEOR Wells	9.31	830.38	7.02	13.69	0.93	0.93
VOCDD (Flare)	14,273	MMBtu/hr	34.32	37.09	126.02	6.46	6.67	6.67
Total Emissions Title-v O&G Sources			932.08	1,596.68	1,463.76	166.57	432.48	432.48
Total Emissions Small O&G Sources (+10%)			93.21	159.67	146.38	16.66	43.25	43.25
Total Emissions All O&G Sources (TPY)			1,025.29	1,756.34	1,610.14	183.23	475.73	475.73

Table 4.3-20: Estimated Change in Operational Emissions For Stationary Source Equipment

Chang in Equip. Emissions	Change in Capacity	Capacity Units	Kern County Change in Emissions from Stationary Source Equipment					
			NO_X TPY	VOC TPY	CO TPY	SO_X TPY	PM_{10} TPY	$PM_{2.5}$ TPY
SJVAPCD Operational Emissions Threshold (TPY)			10	10	100	27	15	15
Total Emissions All O&G Sources (TPD)			2.80	4.80	4.40	0.50	1.30	1.30

Key:
bbl = barrel
BHP*Hr
CO = carbon monoxide
IC = internal combustion engine
MMBtu/hr = million metric British thermal units per hour
MW = megawatt
NO_X = oxides of nitrogen
O&G = oil and gas
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
SJVAPCD = San Joaquin Valley Air Pollution Control District
SO_X = sulfur oxides
TEOR = thermally enhanced oil recovery
TPD = tons per day
TPY = tons per year
VOCDD = volatile organic compound destruction devices

Permit Exempt Equipment

District Rule 2020 exempts equipment or activities that emit less than 2.0 pounds per day or 75 pounds per year of each air contaminant, and for some special categories of equipment. Most crude oil and natural gas production wells emit less than 2.0 pounds per day and as such are permit exempt pursuant to Rule 2020. However, at a Project level, the combined emissions from permit exempt equipment at wells could result in significant impacts because oil and gas wells operations generate fugitive VOC emissions from well-head piping components and from downstream equipment, the latter normally accounted for on District permits. Fugitive VOC emissions from wells are subject to leak detection and repair requirements pursuant to District Rule 4409 and Rule 4401.

Fugitive VOC emissions from the wells were estimated based on the total number of active and idle wells in Kern County (see Table 4.3-21), and were determined using weight fraction of VOCs for light oil and heavy oil obtained from the U.S. Department of Interior, Users Guide for 2014 Gulfwide Offshore Activities Dat4a System (Bureau of Ocean Energy Management 2014), and EPA-approved average leak rate equations for a 2,000 ppmv leak. The calculation procedures include the recommendations contained in District Policy APR2015. The uncontrolled and the controlled fugitive VOC emissions from the wells, on a County-wide basis are summarized below. The number of idle wells is the same for every Project year 2015 – 2035, and was calculated as the average of the number of idle wells reported to CalGEM from 1999 through 2014.

Table 4.3-21: Uncontrolled and Controlled Fugitive Volatile Organic Emissions

Year	Subarea	Active wells	Idle wells	Fugitive VOC (tons per year)
2012	Western	27,873	7,661	2,059
	Central	413	114	68
	Eastern	14,742	4,052	121
	Totals	43,028	11,827	2,247
2035	Western	37,205	6,254	2,511
	Central	1,321	222	199
	Eastern	31,511	5,297	236
	Totals	70,037	11,773	2,946
SJVAPCD Threshold[(a)]				10

Note:
(a) The SJVAPCD threshold is set for Reactive Organic Gases (ROG). The Kern County California Environmental Quality Act Implementation Document (June 2004) states the equivalence of ROG and VOC.
Key:
SJVAPCD = San Joaquin Valley Air Pollution Control District
VOC = volatile organic compound

The VOC fugitive emissions from permit exempt equipment would exceed the SJVAPCD threshold for ROG of 10 tons per year. ROG, which is an ozone precursor, is a criteria pollutant for which the Project region is nonattainment. Therefore, the VOC fugitive emissions would have a significant impact.

Mobile Sources

Mobile emissions sources include on-road sources of emission, such as gasoline-fueled light-duty autos and heavy-duty diesel trucks; off-road sources, such as trucks and tractors, and portable equipment, such as accumulators, generators, and pumps. Emissions are generated from three operational activities: routine business travel, routine well operations (and facility inspections), and routine well maintenance. Routine business travel includes employee and contractor commute and the transport of material needed for daily business; emissions are generated by on-road sources and fugitive dust. Routine well operations include onsite travel on paved and unpaved oilfield roads to conduct daily field operations; emissions are generated by on-road sources and fugitive dust. Routine well maintenance includes travel and use of equipment to conduct maintenance and treatment activities.

The analysis of emissions generated by mobile sources include emissions and fugitive dust generated by on-road sources during routine business travel and routine well operations; and by on-road, off-road, and portable equipment sources during routine well maintenance. Emission factors for the on-road mobile sources were calculated using the EMFAC2011 model; emission factors for off-road sources and portable equipment were calculated using the OFFROAD2011 model. Final emissions were calculated combining the emission factors with activity data obtained from industry or from well records obtained from CalGEM. The assumptions and factors associated with each of these types of mobile sources are discussed in detail below.

Routine Business Travel

This activity includes employee and contractor commute and the transport of material needed for conducting day-to-day business. Gasoline fueled light duty autos were assumed for daily commute and general business activities, and heavy-duty diesel trucks (T7-Single) were assumed for the transport of material and supplies. The number of vehicle trips per year depends on the number of petroleum industry employees and the average vehicle occupancy.

The number of people employed by the petroleum industry during the baseline year was obtained from the U.S. Bureau of Labor Statistics. The 2012 baseline employment was allocated to the individual planning zones based on the percentages of the active wells included in each Subarea during 2012. Employment in future Project years in was assumed proportional to the number of active wells.

SJVAPCD Rule 9410 (Ride Sharing) requires that companies with more than 100 employees reporting to the same location participate in a ride sharing program, and estimates the average vehicle occupancy expected to be achieved.

Emissions generated by routine business travel are estimated in Table 4.3-22. Truck trips required for the transportation of freight and miscellaneous supplies were calculated using “truck trip generation equations” derived from the report *Truck Trip Generation Study, City of Fontana,* *August 2003*. The vehicle miles traveled per trip was determined based on a weighted average travel distance to the wells in the Subareas. Fugitive dust emissions resulting from on-road travel were calculated using the EPA AP42 procedure.

Table 4.3-22: Estimated Annual Criteria Pollutant Emission Generated by Routine Business Travel (tons per year)

Year	NO_X	ROG	CO	SO_X	PM_{10}	$PM_{2.5}$
2012	93.1	26.2	258.7	0.5	14.8	5.8
2035	28.5	11.1	121.3	0.8	21.2	7.2

Key:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SO_X = sulfur oxides

Routine Well Operations

Emissions generated by routine well operations are estimated in Table 4.3-23. This activity includes onsite travel on paved and unpaved oilfield roads to conduct day-to-day field operations. Offsite travel on paved public roads to reach the oilfield destination is accounted for in “Routine Business Travel.”

Oilfield production facilities and wells are routinely inspected to ensure proper operation. Light duty, gasoline fueled trucks are assumed to provide transportation for these types of operational activities. Chemical treatment of wells to prevent corrosion and scale formation may also be conducted using light duty gasoline fueled trucks as well as heavy duty diesel fueled trucks required for delivery of chemicals.

The number of annual trips for the day-to-day management of wells was calculated assuming that the wells are inspected on a weekly basis, and that an oilfield operator manages 200 wells with one trip.

Actively producing crude oil and natural gas wells are normally treated to prevent corrosion and scale formation. Treatment is usually handled by an oilfield service companies. Onsite travel for well treatment to prevent corrosion and scale formation depends on the type of treatment provided to the well. For each well, 180 well site visits per year for treatment were assumed. Trips to the well site are about evenly distributed between light-duty truck trips and heavy-duty trucks trips. Onsite vehicle miles traveled per trip was estimated for two cases: travel to permitted equipment, and travel to well site locations.

Emissions generated by activities related to inspection of facility equipment are estimated in Table 4.3-24. Facilities were assumed to be inspected every other workday. The number of facilities was increased by 10% to account for non-permitted sources. The average trip length for inspection and operation of permitted equipment included within a Subarea was calculated based on the equipment locations within the Subarea. The average trip length for well surveillance and treatment was determined from the average travel distance between the wells. Onsite travel was assumed to occur for 90% on unpaved oilfield roads.

Routine Well Maintenance (Pulling)

Emissions generated by routine well maintenance are estimated in Table 4.3-25. Well maintenance (or well workover or pulling) includes routine activities conducted on downhole equipment to maintain the well in proper operating conditions. It entails on-road and off-road mobile sources and portable equipment.

Well pulling counts were estimated to be equal to 50% of the total active oil and gas production wells, based on data provided by one operating company and discussions with other company representatives.

The number of vehicle trips depends on the number of days required for maintenance, which, in turn, depends on the well depth. The well depth and the number of days required to complete the activity is also needed to calculate the total number of operating hours and the emissions resulting from the use of off-road mobile sources and portable equipment required. The number of days required for conducting well maintenance was determined from data provided by one operating company. The equipment required for conducting well maintenance activities was obtained from one oilfield production company (Vector 2015).

Fugitive dust emissions from onsite travel were estimated assuming that 90% of the onsite travel occurred on unpaved oilfield roads.

Total Mobile Sources Emissions

The total emissions generated by mobile sources including routine business travel, well operations, facility inspection, and well maintenance are calculated in Table 4.3-26.

Table 4.3-23: Estimated Annual Emission Generated by Routine Well Operations

Year	Subarea	Well Count	Criteria Emissions (tons per year)						Emission Factors (lbs. per year per well)					
			NO_X	VOC	CO	SO_X	PM_{10}	$PM_{2.5}$	NO_X	VOC	CO	SO_X	PM_{10}	$PM_{2.5}$
2012	Western	27,873	54.05	1,594.54	207.54	0.07	127.68	13.48	3.88	114.41	14.89	0.00	9.16	0.97
	Central	413	1.09	53.76	3.36	0.00	8.62	0.88	5.28	260.33	16.27	0.01	41.73	4.27
	Eastern	14,742	29.17	116.15	110.07	0.04	62.67	6.66	3.96	15.76	14.93	0.01	8.50	0.90
	TOTALS	**43,028**	**84.31**	**1,764.44**	**320.97**	**0.11**	**198.97**	**21.02**	**3.92**	**82.01**	**14.92**	**0.01**	**9.25**	**0.98**
2035	Western	37,205	53.47	2,094.43	90.99	0.13	169.72	17.36	2.87	112.59	4.89	0.01	9.12	0.93
	Central	1,321	2.01	170.67	3.39	0.01	27.52	2.78	3.04	258.39	5.13	0.01	41.66	4.21
	Eastern	43,609	62.88	303.68	106.84	0.16	184.53	18.91	2.88	13.93	4.90	0.01	8.46	0.87
	TOTALS	**82,135**	**118.35**	**2,568.77**	**201.22**	**0.30**	**381.77**	**39.05**	**2.88**	**62.55**	**4.90**	**0.01**	**9.30**	**0.95**

Key:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SO_X = sulfur oxides
VOC = volatile organic compound

Table 4.3-24: Estimated Annual Emission Generated by Facility Inspection

Year	Subarea	Criteria Emissions (tons per year)					
		NO_X	VOC	CO	SO_X	PM_{10}	$PM_{2.5}$
2012	Western	0.32	0.30	3.57	0.01	120.05	12.09
	Central	0.02	0.01	0.17	0.00	5.82	0.59
	Eastern	0.10	0.09	1.12	0.00	38.42	3.87
	TOTALS	**0.44**	**0.41**	**4.86**	**0.01**	**164.29**	**16.54**
2035	Western	0.14	0.10	1.39	0.01	169.88	17.10
	Central	0.01	0.01	0.14	0.00	17.45	1.76
	Eastern	0.07	0.04	0.64	0.00	79.80	8.03
	TOTALS	**0.22**	**0.15**	**2.17**	**0.01**	**267.14**	**26.89**

Key:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SO_X= sulfur oxides
VOC = volatile organic compound

Table 4.3-25: Estimated Annual Emission Generated by Routine Well Maintenance

Year	Subarea	Well Count	Criteria Emissions (tons per year)						Emission Factors (lbs. per year per well)					
			NO_X	VOC	CO	SO_X	PM_{10}	$PM_{2.5}$	NO_X	VOC	CO	SO_X	PM_{10}	$PM_{2.5}$
2012	Western	13,932	1,012.71	90.83	667.00	0.86	115.47	68.10	145.38	13.04	95.75	0.12	16.58	9.78
	Central	202	20.78	1.83	13.91	0.02	4.54	1.56	205.79	18.11	137.76	0.19	44.91	15.42
	Eastern	7,367	528.02	47.03	343.60	0.45	58.66	35.24	143.35	12.77	93.28	0.12	15.92	9.57
	TOTALS	**21,501**	**1,561.51**	**139.69**	**1,024.51**	**1.33**	**178.66**	**104.89**	**145.25**	**12.99**	**95.30**	**0.12**	**16.62**	**9.76**
2035	Western	18,603	364.33	35.86	882.58	1.16	73.87	17.04	39.17	3.85	94.89	0.12	7.94	1.83
	Central	660	19.40	1.84	44.14	0.06	11.09	1.65	58.79	5.58	133.75	0.19	33.59	5.00
	Eastern	21,803	417.80	41.18	1,002.99	1.36	81.23	19.30	38.33	3.78	92.01	0.12	7.45	1.77
	TOTALS	**41,066**	**801.54**	**78.88**	**1,929.71**	**2.58**	**166.19**	**37.99**	**39.04**	**3.84**	**93.98**	**0.13**	**8.09**	**1.85**

Key:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SO_X = sulfur oxides
VOC = volatile organic compound

Table 4.3-26: Estimated Annual Emission Generated by Mobile Sources

Year	Activity	Criteria Pollutant Emissions (tons per year)					
		NO_X	VOC	CO	SO_X	PM_{10}	$PM_{2.5}$
2012	Routine Business Travel	93.10	26.20	258.70	0.50	14.80	5.80
	Routine Well Operations	84.31	1,764.44	320.97	0.11	198.97	21.02
	Routine Well Maintenance	1,561.51	139.69	1,024.51	1.33	178.66	104.89
	Facility Inspection	0.44	0.41	4.86	0.01	164.29	16.54
	TOTALS	**1,739.36**	**1,930.74**	**1,609.05**	**1.94**	**556.72**	**148.25**
2035	Routine Business Travel	28.50	11.10	121.30	0.80	21.20	7.20
	Routine Well Operations	118.35	2,568.77	201.22	0.30	381.77	39.05
	Routine Well Maintenance	801.54	78.88	1,929.71	2.58	166.19	37.99
	Facility Inspection	0.22	0.15	2.17	0.01	267.14	26.89
	TOTALS	**948.61**	**2,658.90**	**2,254.40**	**3.69**	**836.30**	**111.13**
SJVAPCD Operational Emissions Threshold (tons per year)		10	10	100	27	15	15

Key:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SO_X = sulfur oxides
VOC = volatile organic compound

The total annual emissions of all criteria pollutants from mobile sources associated with business travel, well operations, facility inspection, and well maintenance do not require air permits and, therefore, would not be offset. Table 4.3-26 indicates that in 2035 these emissions would exceed SJVAPCD Operational Emissions Thresholds with the exception of SO_X. Since the SJV Project region is in nonattainment for PM_{10}, $PM_{2.5}$, and ozone, criteria pollutant emissions from mobile sources operational activities emissions would result in considerable net increase of the criteria pollutants NO_X, VOC, CO, PM_{10}, and $PM_{2.5}$ and would be a significant impact.

Summary of Operational Emissions

In summary, emissions from permitted stationary sources, permit-exempt equipment, and mobile sources at a Project level would result in emissions levels that would exceed the SJVAPCD Operational Emissions Threshold. Only the permitted stationary sources would be required to be offset because it is a condition of SJVAPCD air permit. Since the remaining emissions would exceed the SJVAPCD Construction Emissions Threshold and would not be offset, operational emission would result in considerable net increase of the criteria pollutants NO_X, VOC, CO, PM_{10}, and $PM_{2.5}$ and would be a significant impact.

Criteria Pollutant Modeling

Ambient air quality modeling results for NO_2, SO_2, and CO, PM_{10}, and $PM_{2.5}$ are sometimes warranted for large stationary sources near potentially sensitive receptors. Since the Project consists of Zoning Code Amendments that will regulate a broad range of oil and gas activities located throughout the Project Area, and excludes the types of large stationary sources (e.g., new and expanded cogeneration plants) that could warrant ambient air quality modelling, this modelling was not required to evaluate the potential significance of Project-related air emissions. TAC modelling to assess health risks was completed as described below, and the toxicity of criteria pollutants is discussed above.

Visibility

A visibility screening analysis for each Class I area located within 100 km of the Project was not conducted as the Project is not expected to generate large individual plumes that may be visible at a distance.

Carbon Monoxide “Hot Spots”

The Kern County Air Quality Assessment Guidelines require preparation of a CO “Hot Spots” analysis for projects meeting the following criteria:

- The proposed Project impacts an intersection or roadway identified at Level of Service (LOS) E or worse;
- The proposed Project will add signalization and/or channelization to an intersection; and
- Sensitive receptors, such as residences, schools, hospitals, etc., are located in the vicinity of the impacted intersection or proposed signalization.

A CO "Hot Spots" analysis is not appropriate as the Project does not meet the above criteria.

In summary, emissions from construction and operational activities would violate applicable air quality standards at a Project level, specifically the SJVAPCD Construction and Operational Emissions Thresholds, respectively. Only certain permitted portions of these emissions would be required to be offset under SJVAPCD regulations. The non-permitted portion of the emissions is not required to be offset and is in exceedance of SJVAPCD regulations. Therefore, Project-related impacts on air quality would be significant before mitigation.

Total Project Emissions

Table 4.3-27 presents the annual total estimated emissions from both construction and operational activities (permitted, non-permitted, and permit exempt equipment) for the Project, including:

- Construction of permitted equipment;
- Operation of permitted equipment;
- Construction of permitted-exempt equipment and small production settings;
- Well abandonment;
- Drilling;
- Stimulation;
- Rework;
- Maintenance;
- Operation;
- Fugitive VOC from well heads;
- Routine business travel; and
- Facility inspection.

The annual emissions from operation of permitted equipment have been calculated by dividing the projected change in the permitted equipment emissions at Project build-out in 2035 by the number of Project years from 2015 to 2035 (i.e., 21 years).

Table 4.3-27: Total Estimated Emissions from the Project in Tons per Year

Year	NO_X	ROG	CO	SO_2	PM_{10}	$PM_{2.5}$
2012	14,289	9,957	11,809	406	2,041	1,408
2015	13,677	8,588	11,820	416	1,791	1,328
2016	13,259	8,797	11,968	425	1,814	1,333
2017	12,926	8,991	12,135	434	1,842	1,343
2018	11,988	9,147	12,303	443	1,839	1,322

Table 4.3-27: Total Estimated Emissions from the Project in Tons per Year

Year	NO_X	ROG	CO	SO_2	PM_{10}	$PM_{2.5}$
2019	11,188	9,298	12,474	451	1,841	1,310
2020	10,317	9,473	12,653	460	1,853	1,306
2021	10,038	9,650	12,834	469	1,879	1,317
2022	9,048	9,796	13,022	478	1,879	1,305
2023	8,804	9,964	13,184	487	1,904	1,314
2024	8,601	10,143	13,349	496	1,931	1,328
2025	8,496	10,300	13,513	505	1,962	1,343
2026	7,812	10,442	13,689	514	1,968	1,338
2027	7,769	10,605	13,852	522	2,007	1,356
2028	7,691	10,772	14,014	531	2,041	1,374
2029	7,694	10,915	14,166	540	2,076	1,396
2030	7,783	11,071	14,329	549	2,118	1,422
2031	7,872	11,224	14,491	558	2,159	1,447
2032	7,957	11,384	14,647	567	2,197	1,472
2033	8,050	11,522	14,816	576	2,238	1,498
2034	8,131	11,667	14,964	584	2,276	1,523
2035	8,215	11,809	15,121	593	2,316	1,548

Key:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SJVAPCD = San Joaquin Valley Air Pollution Control District
SO_2 = sulfur dioxides

Table 4.3-28 presents the total estimated emissions from the Project from construction and operation, including equipment and mobile sources, and excluding the permitted emissions requiring offsets under District regulations. Tables 4.3-28 and 4.3-29 include emissions estimates from:

- Construction of permitted-exempt equipment and small production settings;
- Well abandonment;
- Drilling;
- Stimulation;
- Rework;

- Maintenance;
- Operation;
- Fugitive VOC from well heads;
- Routine business travel; and
- Facility inspection.

Table 4.3-28: Total Estimated Emissions from the Project Non-Permitted Equipment and Activities in Tons per Year

Year	NO_X	ROG	CO	SO_2	PM_{10}	$PM_{2.5}$
2012	11,794	5,614	8,555	12	1,182	555
2015	11,133	4,162	8,489	12	910	452
2016	10,666	4,287	8,561	13	910	434
2017	10,284	4,398	8,651	13	915	421
2018	9,297	4,470	8,742	13	889	378
2019	8,448	4,537	8,837	13	869	343
2020	7,529	4,628	8,939	13	858	316
2021	7,201	4,722	9,043	13	861	305
2022	6,162	4,784	9,155	14	839	270
2023	5,869	4,869	9,240	14	841	257
2024	5,618	4,964	9,328	14	846	248
2025	5,463	5,038	9,416	14	854	240
2026	4,731	5,096	9,515	14	837	212
2027	4,639	5,175	9,601	14	854	208
2028	4,512	5,259	9,687	14	866	204
2029	4,467	5,318	9,762	15	878	203
2030	4,507	5,390	9,848	15	897	206
2031	4,547	5,460	9,934	15	915	208
2032	4,583	5,536	10,013	15	931	211
2033	4,628	5,591	10,105	15	949	214
2034	4,659	5,651	10,177	15	964	216
2035	4,695	5,710	10,257	15	982	219

Key:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SO_2 = sulfur dioxides

Because the baseline year of 2012 also included construction of 3,392 new wells and other construction and operational Project activity, Table 4.3-29 shows the incremental new emissions from the Project compared to the baseline year 2012. Table 4.3-29 presents the total estimated incremental increase in emissions from the same Project non-permitted equipment and activities in tons per year as for Table 4.3-28 above.

For construction activities, all non-permitted emissions estimated for each Project year 2015 and 2035 are included in the table.

For operational activities, for each year only the non-permitted emission associated with activities started in 2015 have been included. In particular:

- The incremental emissions from the activities of routine business travels, routine well operations, and facility inspections have been calculated by determining for each year and for each activity the emissions per active well, and then multiplying the emissions per active well by the number of new active wells compared to the baseline active wells;
- The incremental emissions for fugitive VOC from well heads have been calculated by determining for each year the fugitive VOC per well (including active plus idle wells), and then multiplying the fugitive VOC per well by the new wells (active plus idle) compared to the baseline number of active plus idle wells; and
- The incremental emissions from routine well maintenance have been calculated by determining for each year the emissions per well undergoing maintenance, and then multiplying them by the incremental number of well undergoing maintenance compared to the baseline year.

Therefore, Table 4.3-29 presents the total non-permitted incremental emissions from the Project, excluding the non-permitted emissions from oil and gas production and processing activities initiated before the start of the Project in 2015.

Table 4.3-29: Total Estimated Incremental Emissions from the Project Non-Permitted Equipment and Activities in Tons per Year

Year	NO_X	ROG	CO	SO_2	PM_{10}	$PM_{2.5}$
2015	11,064	1,919	8,320	12	731	430
2016	10,607	2,055	8,415	12	735	413
2017	10,231	2,189	8,524	12	742	401
2018	9,251	2,277	8,630	12	716	358
2019	8,407	2,360	8,736	13	698	323
2020	7,495	2,460	8,844	13	689	296
2021	7,176	2,574	8,953	13	696	286
2022	6,143	2,650	9,069	13	676	251
2023	5,852	2,749	9,159	13	679	238
2024	5,601	2,852	9,250	13	687	229

Table 4.3-29: Total Estimated Incremental Emissions from the Project Non-Permitted Equipment and Activities in Tons per Year

Year	NO_X	ROG	CO	SO_2	PM_{10}	$PM_{2.5}$
2025	5,447	2,944	9,340	14	696	221
2026	4,714	3,014	9,441	14	682	194
2027	4,623	3,106	9,529	14	695	189
2028	4,496	3,196	9,616	14	708	185
2029	4,451	3,273	9,693	14	722	184
2030	4,491	3,356	9,780	14	741	187
2031	4,531	3,437	9,866	14	760	190
2032	4,568	3,519	9,946	15	777	193
2033	4,612	3,590	10,039	15	796	196
2034	4,644	3,660	10,112	15	813	198
2035	4,680	3,729	10,192	15	831	201

Key:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SO_2 = sulfur dioxides

Table 4.3-30 presents the total estimated incremental emissions from the Project non-permitted equipment and activities in tons per year, divided by the projected number of new wells for each year that was used in the calculation of the emissions.

Table 4.3-30: Total Estimated Incremental Emissions from the Project Non-Permitted Equipment and Activities per New Well in Tons per Year

Year	New Projected Wells	NO_X	ROG	CO	SO_2	PM_{10}	$PM_{2.5}$
2015	3,966	2.79	0.48	2.10	0.003	0.18	0.11
2016	3,970	2.67	0.52	2.12	0.003	0.19	0.10
2017	3,976	2.57	0.55	2.14	0.003	0.19	0.10
2018	3,982	2.32	0.57	2.17	0.003	0.18	0.09
2019	3,988	2.11	0.59	2.19	0.003	0.18	0.08
2020	3,994	1.88	0.62	2.21	0.003	0.17	0.07
2021	4,000	1.79	0.64	2.24	0.003	0.17	0.07
2022	4,006	1.53	0.66	2.26	0.003	0.17	0.06
2023	4,012	1.46	0.69	2.28	0.003	0.17	0.06
2024	4,018	1.39	0.71	2.30	0.003	0.17	0.06
2025	4,024	1.35	0.73	2.32	0.003	0.17	0.05
2026	4,030	1.17	0.75	2.34	0.003	0.17	0.05
2027	4,036	1.15	0.77	2.36	0.003	0.17	0.05
2028	4,042	1.11	0.79	2.38	0.003	0.18	0.05
2029	4,048	1.10	0.81	2.39	0.003	0.18	0.05
2030	4,054	1.11	0.83	2.41	0.004	0.18	0.05
2031	4,060	1.12	0.85	2.43	0.004	0.19	0.05
2032	4,066	1.12	0.87	2.45	0.004	0.19	0.05
2033	4,071	1.13	0.88	2.47	0.004	0.20	0.05
2034	4,077	1.14	0.90	2.48	0.004	0.20	0.05
2035	4,083	1.15	0.91	2.50	0.004	0.20	0.05
Average Annual Incremental Emissions per Well		**1.58**	**0.72**	**2.31**	**0.003**	**0.18**	**0.06**

Key:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SO_{2X} = sulfur dioxides

Table 4.3-31 presents the total estimated incremental increase in emissions from the Project non-permitted equipment and activities in tons per year, obtained by multiplying the emissions per well calculated in Table 4.3-30 by the maximum number of new wells that may be authorized, namely 3,647 new wells every year. The bottom line of the table shows the average annual incremental emissions of the Project, obtained by averaging the annual projected incremental emissions over the Project years 2015 to 2035.

Table 4.3-31: Total Estimated Incremental Emissions from the Project Non-Permitted Equipment and Activities per New Well in Tons per Year

Year	New authorized wells	NO_X	ROG	CO	SO_2	PM_{10}	$PM_{2.5}$
2015	3,647	10,174	1,765	7,650	11	672	396
2016	3,647	9,744	1,888	7,730	11	675	380
2017	3,647	9,385	2,007	7,818	11	681	368
2018	3,647	8,473	2,085	7,904	11	656	328
2019	3,647	7,688	2,158	7,989	12	638	295
2020	3,647	6,844	2,246	8,076	12	629	270
2021	3,647	6,543	2,347	8,163	12	634	260
2022	3,647	5,592	2,412	8,256	12	615	229
2023	3,647	5,320	2,499	8,325	12	618	216
2024	3,647	5,084	2,588	8,396	12	623	208
2025	3,647	4,936	2,668	8,465	12	631	201
2026	3,647	4,266	2,728	8,544	12	617	175
2027	3,647	4,178	2,807	8,610	13	628	171
2028	3,647	4,057	2,884	8,676	13	638	167
2029	3,647	4,010	2,949	8,732	13	650	166
2030	3,647	4,040	3,019	8,798	13	667	168
2031	3,647	4,070	3,087	8,862	13	683	171
2032	3,647	4,097	3,156	8,921	13	697	173
2033	3,647	4,132	3,216	8,993	13	713	175
2034	3,647	4,154	3,274	9,045	13	727	178
2035	3,647	4,180	3,331	9,104	13	742	180
Average Project Annual Incremental Emissions		**5,760**	**2,625**	**8,431**	**12**	**659**	**232**

Key:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
ROG = reactive organic gases
SO_2x = sulfur dioxides

Construction and operations associated with the Project would occur concurrently and have to be considered in total. Total Project emissions continue to be a major emission source as identified in Table 4.3-28, as well as incremental increases in Project emissions as shown in Table 4.3-29. Because the Project's incremental emissions would exceed the SJVAPCD thresholds for all criteria pollutants except SO_2 for which the Project region is nonattainment under an applicable federal or state ambient air quality standard, this impact is considered significant before mitigation.

The implementation, as mitigation, of a DMC or VERA to reduce criteria pollutants of NO_X, ROGs, and PM net incremental emissions generated by a project has been incorporated into development projects in Kern County since 2008. They are not a “voluntary” agreement with the SJVAPCD but are mandated by enforceable mitigation measures and are, therefore, called DMC. The emission reductions required by a DMC are implemented within the SJVAB in quantities sufficient to fully mitigate the Project’s air quality impacts such that development of the Project could be considered to result in no net increase in the designated criteria pollutant emissions over the criteria pollutant emissions that would otherwise exist without the development of the Project, all to be verified by the SJVAPCD. Thus, the DMC results in greater reductions than would otherwise occur under the District’s ISR, since the ISR does not require ROG reductions and the ISR only requires a percentage of reductions rather than full reductions of NO_X and PM resulting from Project construction and operations. When adopting the ISR and the subsequent VERA/DMC programs, the District acknowledges that as ROG is a precursor to ozone, the reductions are not required in the ISR. (Note: In the VERA/DMC, the reductions are achieved by increasing the NO_X and PM tonnage for Project levels; see SJVAPCD (2005a); this and other key SJVAPCD documents are included as Appendix L of the 2015 FEIR (SREIR Volume 4). As the actual amount of ROG reductions achieved from NO_X and PM_{10} reductions is not absolutely certain, Project emissions are still considered significant and unavoidable; however, all feasible and reasonable mitigation has been required to reduce criteria pollutants as close to “no net increase” as scientifically possible. This approach has been found legally sufficient by court rulings in the following cases; *California Building Industry Assn. v. San Joaquin Valley APCD*, Fresno County Case No. 06 CECG 02100 DS13; *National Association of Home Builders v. San Joaquin Valley Unified Air Pollution Control District*, Federal District Court, Eastern District of California, Case No. 1:07-CV-00820-LJO-DLB; and *Center for Biological Diversity et al. v. Kern County*, Fifth Appellate District, Case No. F061908.

The projects that have been required to implement DMCs are residential, commercial, and industrial projects. Those projects have one developer and a finite construction to completion schedule. The oil and gas activities in the proposed Project will be implemented by hundreds of individual operators, and impacts will occur every year on a varying basis dependent on how many new wells and new activities occur. The number of new wells and activities covered by this SREIR and the new Oil and Gas Conformity Review is a not to exceed of 3,647 permits a year. To implement the required mitigation reductions, the mitigation requires an agreement between the Kern County Board of Supervisors and the SJVAPCD Board for an Oil and Gas Emission Reduction Agreement (OG-ERA) (as described below in MM 4.3-8). The OG-ERA was entered into on August 18, 2016, and is available as Appendix C of this SREIR. The OG-ERA agreement focuses on the core requirement that the calculated emissions, which are not otherwise regulated and offset by District stationary source rules, from NO_X, ROG, and PM (which includes both PM_{10} and $PM_{2.5}$) from Project construction and operations activities shall be mitigated to a level of no net increase. The mitigation will be required, as discussed below, for new well permits under the Oil and Gas Conformity Review and Minor Activities Permit, when applicable.

The mandated emission reductions will be achieved by a menu of options that range from paying a calculated mitigation fee for use in doing emission reduction projects through a grant-type program, to applicants proposing and achieving their own emission reduction projects through an

SJVAPCD-approved process in lieu of paying the fee. The first pathway, the mitigation fee, will involve paying a calculated mitigation fee to the County for each permit to implement the OG-ERA. The mitigation fee shall be placed in a fund, established by the Board of Supervisors, with an additional administrative fee of 4% collected for the SJVAPCD. Expenditure of the mitigation funds shall be for certified air quality reduction projects managed by the SJVAPCD, in close consultation with Kern County. Final determination of air quality reductions achieved shall be under the determination of the SJVAPCD. Furthermore, selection of specific projects shall be determined by the SJVAPCD in consultation with Kern County. Projects of equal cost-effectiveness to offset criteria pollutants under the OG-ERA would be given priority for Kern County valley locations. The fee will be based and tiered to address different configurations of equipment that could be used, as well as other variables such as the depth of the well. Some examples of such changes to equipment are adding diesel particle filters or upgrading to cleaner engines that are not currently required. The fee shall be adjusted as of January 1 of each year, and shall be tied to the prior year's average cost effectiveness, as published in the SJVAPCD's "Annual Report on the District's Indirect Source Review Program" (SJVAPCD 2019*a*)

Another mitigation menu option would be for an applicant, instead of paying the fee, at the time of permit application, to present a proposed emission reduction project with supporting documentation that describes the proposed project and emission reductions. The presentation would include a description of the methodology and quantifications of emission reductions for NO_X, ROG, and/or PM (including both PM_{10} and $PM_{2.5}$). The proposed emission reduction project package would be reviewed by the SJVAPCD for methodology and verification of the emission reduction tonnage requested, and reviewed by both Kern County and the SJVAPCD for the Project location and structure and timeline for implementation. The reductions will then be used as credits for compliance with the mitigation measure requirements. Examples of emission reduction projects that could be submitted by the applicant in lieu of mitigation fee payments include changes to Applicant-owned fleets and trucks and implementation of van pools or other trip reduction programs that can be quantified and enforced.

As an agreement between the SJVAPCD and the County, the requirements of the OG-ERA are limited to those impacts resulting from the Project that occur within the SJVAB. However, as areas of the Project are near the border of the SJVAB and the South Coast Air Basin, some mobile source emissions associated with the Project could occur outside the SJVAB. Although the OG-ERA does not require full offsets of these out of basin emissions, projects under consideration for implementation would result in reduction of potential transport and cross-basin emissions. Other emission reduction projects that are implemented pursuant to the OG-ERA may also result in additional emission reductions within the South Coast Air Basin.

The number of well permits issued annually will vary based on a variety of factors, and can range from 1,800 to 3,647. Air emissions modelling used in this SREIR conservatively assumed a higher well count than 3,647 (with a maximum annual well count of 4,083), despite the fact that the Project Description includes a yearly total not to exceed 3,647. The estimated incremental emissions from Project implementation are provided in Table 4.3-32, below, which shows the next 21 years of permitting and the emissions each year for one well. The emission totals include all Project-related construction and operational activities that are not subject to the District's stationary source permitting and emission offset rules, such as mobile sources like construction equipment, maintenance trucks, employee automobile trips, construction of access roads and well pads, drilling, accessory activities, well operation, and eventual abandonment. Emissions from idled wells are also included. The annual totals also include mandatory emission reductions from existing legal requirements, such as federal and state mandated changes for certain types of engines that will cause NO_X emissions to increase slightly while PM_{10} declines. Project-related construction and operational emissions that are not required to be offset under District stationary source permitting rules are then averaged for all wells over a 20-year period to illustrate how the OG-ERA will generate emission reduction totals. Table 4.3-32 provides the basis for determining the in-lieu fees paid by applicants under the OG-ERA.

Table 4.3-32: Total Estimated per Well Emissions for Consideration in Calculating Oil and Gas Emission Reduction Agreement Fees in Tons per Year

Year	New Projected Wells	NO_X	ROG	PM_{10}	$PM_{2.5}$ [(a)]	Per Well Projected Emissions	Maximum Authorized Wells	Projected Emissions Scaled to 3,647 Wells
2015	3,966	2.79	0.48	0.18	0.11	3.46	3,647	12,611
2016	3,970	2.67	0.52	0.19	0.11	3.37	3,647	12,307
2017	3,976	2.57	0.55	0.19	0.10	3.31	3,647	12,073
2018	3,982	2.32	0.57	0.18	0.09	3.07	3,647	11,214
2019	3,988	2.11	0.59	0.18	0.08	2.87	3,647	10,485
2020	3,994	1.88	0.62	0.17	0.07	2.66	3,647	9,719
2021	4,000	1.79	0.64	0.17	0.07	2.61	3,647	9,524
2022	4,006	1.53	0.66	0.17	0.06	2.36	3,647	8,620
2023	4,012	1.46	0.69	0.17	0.06	2.31	3,647	8,436
2024	4,018	1.39	0.71	0.17	0.06	2.27	3,647	8,296
2025	4,024	1.35	0.73	0.17	0.05	2.26	3,647	8,235
2026	4,030	1.17	0.75	0.17	0.05	2.09	3,647	7,611
2027	4,036	1.15	0.77	0.17	0.05	2.09	3,647	7,613
2028	4,042	1.11	0.79	0.18	0.05	2.08	3,647	7,579
2029	4,048	1.10	0.81	0.18	0.05	2.09	3,647	7,609
2030	4,054	1.11	0.83	0.18	0.05	2.12	3,647	7,726
2031	4,060	1.12	0.85	0.19	0.05	2.15	3,647	7,841
2032	4,066	1.12	0.87	0.19	0.05	2.18	3,647	7,951
2033	4,071	1.13	0.88	0.20	0.05	2.21	3,647	8,061

Table 4.3-32: Total Estimated per Well Emissions for Consideration in Calculating Oil and Gas Emission Reduction Agreement Fees in Tons per Year

Year	New Projected Wells	NO_X	ROG	PM_{10}	$PM_{2.5}$ [(a)]	Per Well Projected Emissions	Maximum Authorized Wells	Projected Emissions Scaled to 3,647 Wells
2034	4,077	1.14	0.90	0.20	0.05	2.24	3,647	8,155
2035	4,083	1.15	0.91	0.20	0.05	2.26	3,647	8,253
Average		**1.58**	**0.72**	**0.18**	**0.06**	**2.48**		**9,044**

Note:
[(a)] $PM_{2.5}$ is a subset of PM_{10}, and these values were calculated based on the percentage of $PM_{2.5}$ as compared to PM_{10}, as shown in Table 4.3-31.

Key:
NO_X = oxides of nitrogen
PM = particulate matter
ROG = reactive organic gases

As shown in Table 4.3-32, based on emission estimates for the average emissions per new well over the next 21 years, the OG-ERA would reduce per well emissions from the proposed Project by an estimated total ranging from 3.46 tons per year to 2.26 tons per year. Based on that estimated average, the OG-ERA will generate between 8,253 tons to 12,611 tons per year of combined ROG, NO_X, PM_{10}, and $PM_{2.5}$ emission reductions if 3,647 wells are drilled each year.

To determine an emission value from which to base the OG-ERA fee that applicants would pay, the emission estimates in Table 4.3-32 for an individual well were separated by Subarea (or zone) and calculated based on well depth per 1,000 feet (e.g., 1,000-foot well, 2,000-foot well) from 1,000 feet to greater than 24,000 feet. Total ROG, NO_X, PM_{10}, and $PM_{2.5}$ emissions were calculated to achieve an emission value per well depth per subarea for OG-ERA fee calculation. This emission value is then multiplied by the prior year's average cost effectiveness for emission reduction projects in the SJVAB, as published in the SJVAPCD's "Annual Report on the District's Indirect Source Review Program" to obtain the fee payable by applicants under the OG-ERA. Exhibit C to the OG-ERA (see Appendix C of this SREIR) provides the per well emissions and related fees of the date of adoption of the OG-ERA and the December, 2019 current fees are listed here:
https://psbweb.co.kern.ca.us/planning/pdfs/oil_gas/oil_gas_air_quality_mit_fees_010120.pdf.
No changes to per-well emissions have been made since the adoption of the OG-ERA, and only the fee per ton changes each year based on the prior year's SJVAPCD Report.

Thus, the OG-ERA fees include the total tonnage of emissions that will occur from implementation of the particular well that is being permitted, including ROG, NO_X, PM_{10}, and $PM_{2.5}$ emissions. As explained above, as both PM_{10} and $PM_{2.5}$ emissions from all Project activities were included in the air quality analysis, as estimated in Tables 4.3-31 and 4.3-32, these emissions formed the basis of the calculation of emissions to determine the OG-ERA fee. Applicants paying the applicable OG-ERA fee are thus fully mitigating for all Project emissions, including mitigating for PM2.5 emissions.

Table 4.3-32 also combines PM_{10} and $PM_{2.5}$ emissions into a total PM value for use in the calculation of OG-ERA fees and for the tracking of emission reductions achieved by the OG-ERA. This approach was taken for multiple reasons. First, because $PM_{2.5}$ is a subset of PM_{10}, any PM_{10} emissions necessarily contain $PM_{2.5}$ emissions. For this reason, it is difficult to separate $PM_{2.5}$ and $PM_{2.5–10}$ emissions when creating, implementing, and tracking incentive measures that fund emission reduction projects. Second, addressing $PM_{2.5}$ and PM_{10} emissions jointly is the approach that the SJVAPCD had consistently taken in its attainment plans and SIP strategies for achieving both the PM_{10} and $PM_{2.5}$ ambient air quality standards and for achieving emission reductions of both pollutants, particularly through incentive measures like the OG-ERA. In its response to comments on its 2018 Plan for the 1997, 2006, and 2012 $PM_{2.5}$ standards, the SJVAPCD replied to a comment requesting specific $PM_{2.5}$ limits as part of its ISR program, which currently only addresses PM10. The SJVAPCD stated:

> "The ISR rule targets NOx and PM10 emissions from mobile source equipment related to the project construction and operational activities. Particulate matter emissions from mobile source equipment emissions are overwhelmingly PM2.5, a subset of PM10. Therefore, the PM10 emission reductions achieved by our emission reduction incentive grants through expenditure of offsite fees collected under ISR result directly in PM2.5 emission reductions. In other words, PM10 emissions increases are being offset by emissions reductions that are overwhelmingly PM2.5, a positive impact on PM2.5 concentrations. Adding a PM2.5 emission reduction requirement to the existing PM10 emission reduction target will not contribute to further reduce actual PM2.5 emissions." (SJVAPCD 2020*a*).

As explained above, CARB has accepted this approach to reducing $PM_{2.5}$ emissions to reach attainment of the $PM_{2.5}$ NAAQS and CAAQS, as it approved the SJVAPCD's 2018 $PM_{2.5}$ Plan in January 2019. In doing so, CARB made no comment as to the necessity to separately account for PM2.5 reductions in incentive measures in the Plan. The calculation of emission reductions necessary for the OG-ERA thus includes $PM_{2.5}$, but also relies on the judgment of the SJVAPCD, the expert agency with responsibility for air quality in the Project area, that differentiating between $PM_{2.5}$ and PM_{10} for purposes of incentive measures and tracking reductions from emission reduction projects, such as the OG-ERA, is not necessary and would not contribute to further reduction of actual $PM_{2.5}$ emissions.

The SJVAPCD 2015 Annual Report on the Indirect Source Review Program, the basis for Exhibit C to the OG-ERA, shows the cost as $7,231 per ton to implement emission reduction projects. Based on this cost, which is adjusted for depth of well and equipment configuration, the mitigation fee in 2016 ranged from approximately $66,000 to $6,900, per well (up to 10,000 feet, which includes the vast majority of wells drilled in Kern County) including a 4% administrative cost to the Air District. The estimated amount generated every year for mitigation fees to fund emission reduction projects based on the 2016 cost-effectiveness value thus ranges from $118 million to $12 million (based on an estimate of 1,800 permits per year). The total fees collected by the OG-ERA over 21 years (again using the estimate of 1,800 permits per year and the 2015 cost-effectiveness value) will thus range from $2.5 billion to $260 million. ~~*Future year*~~ SJVAPCD Annual Reports on the Indirect Source Review Program show the cost-effectiveness to implement emission reduction projects as $7,945 per ton in 2016, $8,123 per ton in 2017, $9,090 per ton in 2018, ~~and~~ $10,025 per ton in 2019*, and $10,927 per ton in 2020*.

Emission reductions funded by the OG-ERA mitigation fees will offset the impacts from the new oil and gas activities resulting in a "no net increase" to contributions of designated criteria air emissions in the entire air basin. While the size and scope of such projects has not been implemented in the SJVAPCD, projects have clearly been implemented in full compliance with the ISR, VERA, and DMCs. CARB also has an existing program called the Carl Moyer Memorial Air Quality Standards Attainment Program (Carl Moyer Program) (CARB 2014b, included as Appendix E of the 2015 FEIR [SREIR Volume 4]) that provides grant funding for cleaner than required engines and equipment. Eligible projects include cleaner on-road, off-road, marine, locomotive, lawn and garden, light duty passenger vehicles, and agricultural equipment. The Carl Moyer Program has quantified and validated that those reductions can be achieved. Based on these existing programs and the expansion of potential emission reduction projects based on the funding that would be available over a 21-year period, the following are examples of potential projects and costs that will achieve the required emission reductions:

Replace and upgrade vehicle fleets for County, cities, and other eligible entities	$50 million
Upgrade school buses for public, private, churches, charitable organizations, and other eligible entities	$150 million
Replace cars in disadvantaged communities	$120 million
Truck upgrades and replacement for eligible entities	$100 million
Fund new and upgraded transit programs	$120 million

It is not feasible at this time to identify and commit to specific projects to provide the reductions needed under the OG-ERA in each year through 2035. It is anticipated that new types of reduction projects will become available as technologies develop over time, and the flexibility of the OG-ERA allows for the mitigation fees to be spent on the most effective emission reduction projects available at the time the fees are received to ensure that emission reductions are achieved for all oil and gas activity over the next two decades.

The OG-ERA states that cost-effectiveness should be a key consideration in selecting among emissions reduction projects to be funded through mitigation fees but also states that emission reduction projects in Kern County should be prioritized ahead of emission reduction projects elsewhere in the SJVAPCD (see Appendix C of this SREIR). The OG-ERA attempts to balance these policy goals by stating that, in selecting emission reduction projects, if Kern County emission reduction projects are not the most cost-effective, then Kern County projects costing up to $250 per ton more than the most cost-effective emission reduction projects outside Kern County shall nevertheless be selected by the SJVAPCD to spend up to 20% of the mitigation fee funds available. If emission reduction projects in Kern County cost in excess of $250 per ton more than the most cost-effective emission reduction projects in other counties, then those projects outside Kern County may be selected by the SJVAPCD to achieve the required emission reductions. In *this way, the OG-ERA prioritizes emission reduction projects in Kern County, but also strives to achieve the most emission reductions possible with the least money, valuing cost-effectiveness in addition to location of project. Thus,* while emission reduction projects will be prioritized in Kern County, ~~future years~~ *implementation of the OG-ERA* will involve *some* emission reduction projects in other counties in the SJVAB or even outside the valley for mobile sources that bring emissions into the valley, such as transporting freight from the Port of Los Angeles and Ontario centers.

The following discussion describes what has occurred under the OG-ERA since 2015.

As detailed in Table 4.3-AA, between December 9, 2015 (the first day following Ordinance enactment) and November 30, 2019 (the last day of the most recent reporting period), 7,963 oil and gas permits were issued and mitigation fee payments totaling $88,937,939.07 were collected.

Table 4.3-AA: Oil and Gas Permit Issuance and Mitigation Fee Payment History

Permitting Year[a]	***Conformity Review Permits***	***Minor Rework Permits***	***Minor Activity Review Permits***	***Mitigation Fee Payments***
2016	*1,122*	*NA[b]*	*72*	*$3,329,332.87*
2017	*1,891*	*399*	*105*	*$14,443,711.93*
2018	*1,055*	*903*	*151*	*$32,268,388.27*
2019	*1,208*	*880*	*177*	*$38,896,506.00*
Total:	***5,276***	***2,182***	***505***	***$88,937,939.07***

Source: Kern County 2019; page 4–5.
Notes:
[a] Each "permitting year" runs from December 1 of the previous year to November 30 of the permitting year.
[b] Minor rework permitting under the Ordinance initiated in May 2015.
Key: NA = not applicable

OG-ERA mitigation fee payments began being transmitted to the SJVACPD starting in 2016. Although the OG-ERA is only one of 45 emission reduction agreements approved by the SJVACPD as of June 20, 2020, it accounts for about 91% of all mitigation fees received by the SJVACPD pursuant to emission reduction agreements (ERAs), as shown in Table 4.3-BB.

Table 4.3-BB: Total Mitigation Fee Payments Received by SJVACPD under the OG-ERA and All Other Emission Reduction Agreements

Reporting Year[a]	***Total Number of ERAs[b]***	***Total Fees Received under the OG-ERA***	***Total Fees Received under All ERAs***
2017	*32*	*$6,245,624*	*$8,998,493*
2018	*36*	*$18,440,142*	*$20,287,656*
2019	*41*	*$41,014,125*	*$42,915,629*

Table 4.3-BB: Total Mitigation Fee Payments Received by SJVACPD under the OG-ERA and All Other Emission Reduction Agreements

Reporting Year[(a)]	Total Number of ERAs[(b)]	Total Fees Received under the OG-ERA	Total Fees Received under All ERAs
2020	45	$19,019,208	$20,534,361
Total:		$84,719,099	$92,736,139

Sources: SJVAPCD 2017, 2018b, 2019b, 2020c
Notes:
(a) Each "Reporting Year" runs from July 1 of the previous year to June 20 of the Reporting Year.
(b) This figure represents a running cumulative total. In 2018, the SJVAPCD entered into four new ERAs, and in 2019 it entered into five new ERAs.
Key:
ERA = emission reduction agreement
OG-ERA = Oil and Gas Emission Reduction Agreement
SJVAPCD = San Joaquin Valley Air Pollution Control District

As shown in Table 4.3-CC, the SJVAPCD has made steady progress funding emission reduction projects using mitigation fees generated by ERAs, including the OG-ERA. In 2016, about 17.5% of available fee revenues were used or encumbered to fund emission reduction projects during that reporting year, but this figure jumped to about 63% in 2017 and generally held steady in 2018, even though total revenues more than doubled year over year. In 2019, fee revenues again more than doubled, year over year, but the percentage of fees used or encumbered to fund emission reduction projects declined from 60% to 28.2%. In 2020, the percentage of fees used or encumbered again rose to 35.5%. In 2020, the amount of fee revenues encumbered to fund projects rose significantly.

Table 4.3-CC: Emission Reduction Agreement Mitigation Fee Revenue Fiscal Summary

	2016	2017	2018	2019	2020
Beginning Fee Revenue Balance	$1,341,174	$8,557, 592	$13,789,083	$24,680,593	$55,134,891
Mitigation Fees Received	$8,612,006	$8,998,493	$20,287,656	$42,915,629	$20,534,361
Fee Revenues Spent on ERPs	($1,395,589)	($3,767,002)	($9,396,146)	($12,461,331)	($10,220,187)
Percentage of Fee Revenues Used to Fund ERPs	14%	21.4%	27.6%	18.4%	13.5%
Ending Balance	$8,557,592	$13,789,083	$24,680,593	$55,134,891	$65,449.064
Amount of Fee Revenues Encumbered to Fund ERPs	($346,083)	($7,346,773)	($11,055,731)	($6,630,551)	($16,640,881)
Percentage of Ending Balance Encumbered to Fund ERPs	0.4%	53%	44.9%	12%	25.4%
Ending Unencumbered Fund Balance	$8,211,509	$6,442,310	$13,624,863	$48,504,340	$48,808,183

Table 4.3-CC: Emission Reduction Agreement Mitigation Fee Revenue Fiscal Summary

	2016	2017	2018	2019	2020
Percentage of Available Fees Used, or Encumbered, to Fund ERPs	17.5%	63.3%	60%	28.2%	35.5%

Sources: SJVAPCD 2016b, 2017, 2018b, 2019b, 2020c
Key:
ERP = emission reduction project

As shown in Table 4.3-DD, NO_X reductions attributable to emission reduction projects funded by ERA mitigation fees have increased from 181 tons in 2016 to 1,068 tons in 2020. PM_{10} emission reductions attributable to emission reduction projects significantly increased from 5 tons in 2016 to 181 tons in 2018, declined to 63 tons in 2019, but increased to 109 tons in 2020.

Table 4.3DD: Emission Reductions Achieved from All Emission Reduction Projects Fully Funded by Mitigation Fees Generated by Emission Reduction Agreements

Year	Number of Funded Projects	Achieved Emission Reductions from All Emission Reduction Projects Funded by Mitigation Fees		
		NO_X	PM_{10}	Total
2016	86	181 tons	5 tons	186 tons
2017	256	381 tons	96 tons	477 tons
2018	272	853 tons	181 tons	1,034 tons
2019	253	1,220 tons	63 tons	1,283 tons
2020	2,727	959 tons	109 tons	1,068 tons
Total:	**3,594**	**3,775 tons**	**454 tons**	**4,048 tons**

Sources: SJCAPCD 2016b, 2017, 2018b, 2019b, 2020c
Key:
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns

Though not all mitigation fee monies are spent the same year they are received, and thus there may be a lag between the time when emitting activities begin and emission reduction projects are implemented, the fees received by the SJVAPCD have ramped up quickly from 2016 to 2019, resulting in over five times as much fee monies collected in 2018–2019 as in 2016–2017. Because of this recent large increase in mitigation fees obtained per year, some portion of the fees received by the SJVAPCD are being carried over to the next year while the SJVPACD identifies and funds emission reduction projects. To date, the SJVAPCD has received $101,348,145 in mitigation fees and has spent or encumbered $79,260,274. As the OG-ERA mitigation fees account for approximately 91% of the VERA fees received by the SJVAPCD, it is reasonable to conclude that 91% of the fees spent by the SJVAPCD are from OG-ERA mitigation fees. This would result in the SJVAPCD's having spent approximately 78% of the total OG-ERA mitigation fees that it had received as of June 30, 2020. Further, the SJVAPCD 2020 ISR Annual Report, dated September

17, 2020, states that, "[s]ince the [June 30, 2020] end of the reporting period for this report, the vast majority of the unencumbered balance has now been encumbered or is in the process of being encumbered for emission reduction projects during this fiscal year" (SJVAPCD 2020c). Thus, very few to no mitigation fees will be carried over into 2021 by the SJVAPCD. In addition, the SJVAPCD is continuing to ramp up its emission reduction project identification and implementation program, and in particular is attempting to identify large-scale emission reduction projects to fund with OG-ERA fees.

Implementation of the OG-ERA will effectively mitigate for Project emissions of NO_X, ROG, PM_{10}, and $PM_{2.5}$. Table 4.3-31 shows that PM_{10} and $PM_{2.5}$ would have estimated average annual incremental emissions of 659 tons per year of PM_{10} and 232 tons per year of $PM_{2.5}$. This means that of total average annual incremental emissions of PM due to Project implementation, 35% of the emissions are $PM_{2.5}$ emissions and 65% of the emissions are $PM_{2.5–10}$ emissions. Thus, a much smaller total of emission reductions from the OG-ERA are required for $PM_{2.5}$ as compared to $PM_{2.5–10}$.

Further, the example OG-ERA emission reduction projects likely to be implemented with OG-ERA mitigation fees will all reduce $PM_{2.5}$ at higher levels than they will reduce $PM_{2.5–10}$. Example projects mentioned in this SREIR and the 2015 FEIR include:

- Replacing or retrofitting diesel-powered stationary equipment with electric or other lower-emissions engines;
- Replacing or retrofitting diesel-powered school, transit, municipal, and other buses, car fleets, and maintenance equipment with electric or other lower-emission engines;
- Reducing emissions from public infrastructure sources;
- Funding lower-emission equipment for local businesses, schools, and institutions;
- Adding diesel particle filters;
- Upgrading to cleaner engines; and
- Making changes to fleets and trucks, implementing van pools or other trip-reduction programs.

As particulate matter is composed of both $PM_{2.5–10}$ and $PM_{2.5}$, it is necessary to speciate or provide estimates of the chemical composition of, PM emissions to determine what portion of the PM emissions are $PM_{2.5–10}$ or $PM_{2.5}$, respectively. Multiple PM speciation profiles exist and are used to determine what percentage or "weight fraction" of PM emissions are $PM_{2.5–10}$ and $PM_{2.5}$. These profiles are commonly used in air quality modeling, in preparing air quality plans for use in the State's Implementation Plan (SIP, and in adopting air quality reduction measures to determine what emission reductions certain measures would achieve. CARB has published speciation profiles for common sources of PM emissions that are used in all CARB modeling and are also relied on by local air districts to speciate PM emissions (CARB 2018b). CARB's speciation profiles for PM consist of a "PMSIZE" excel spreadsheet that lists various sources of PM emissions and then provides two values for each source of PM emissions, the weight fraction of the PM emissions coming from that source that meets the diameter for $PM_{2.5-10}$, and the weight fraction of the PM emissions coming from that source that meets the diameter for $PM_{2.5}$. Because a particulate that meets the diameter requirement for $PM_{2.5}$ necessarily meets the diameter requirement for PM_{10}, to determine the composition of PM from various sources using the "PMSIZE" spreadsheet, the weight fraction of $PM_{2.5}$ is divided by the weight fraction of PM_{10}. The resulting fraction is that fraction of the PM that is $PM_{2.5}$, while the remainder of the PM is $PM_{2.5-10}$.

Utilizing CARB's speciation profiles and "PMSIZE" spreadsheet, example emission reduction projects that would be funded by the OG-ERA fees would result in the reductions of $PM_{2.5-10}$ and $PM_{2.5}$ shown in Table 4.3-~~AA~~ EE.

Table 4.3-EE: Example Emission Reduction Projects that Could Be Funded by OG-ERA Fees

Example Emission Reduction Project	Source of Emissions	Weight Fraction of $PM_{2.5}$/Total PM	Weight Fraction of PM_{10}/Total PM	Percentage of $PM_{2.5}$ of Total PM_{10}	Percentage of $PM_{2.5-10}$ of Total PM_{10}
Replacing or retrofitting diesel-powered stationary equipment with electric or other lower-emissions engines	Diesel combustion from off-road equipment	0.937	0.96	97.6%	2.4%
Replacing or retrofitting diesel-powered school, transit, municipal, and other buses, car fleets, and maintenance equipment with electric or other lower-emission engines	Diesel combustion from on-road equipment	0.937	0.96	97.6%	2.4%
Reducing emissions from public infrastructure sources	Natural gas-fired stationary combustion engines	1	1	100%	0%
Changes to fleets and trucks, implementation of van pools or other trip-reduction programs	Gasoline combustion from on-road equipment	0.992	0.994	99.8%	1.2%

Key:
PM = particulate matter
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns

As shown above, most of the example emission reduction projects funded by the OG-ERA would reduce diesel emissions, which are almost entirely composed of very small particulates and thus would overwhelmingly reduce $PM_{2.5}$. Other proposed projects, such as reducing infrastructure emissions would also overwhelmingly reduce $PM_{2.5}$ emissions. In fact, all of the potential emission reduction projects listed in the 2015 FEIR and this SREIR would reduce more $PM_{2.5}$ than $PM_{2.5-10}$. In addition, most of the emission reduction projects funded by SJVAPCD's ISR program to date, such as electrifying stationary internal combustion engines, replacing old heavy-duty trucks, and replacing old farm tractors, reduce diesel emissions and, therefore, primarily reduce $PM_{2.5}$.

The EPA recently approved a revision to the SJVAPCD portion of the California SIP to include an incentive measure that would replace off-road mobile, diesel agricultural equipment with newer, lower emitting equipment (EPA 2020). This included a proposed approval of SJVAPCD's request for quantitative credits for $PM_{2.5}$ reductions associated with the program. Thus, EPA recognizes that a valid way to quantify $PM_{2.5}$ reductions expected to be achieved from an incentive measure exists and, thus, it is also feasible to expect that the OG-ERA will achieve $PM_{2.5}$ reductions from the emission reduction projects funded by the OG-ERA to mitigate for Project emissions, as demonstrated in the table of potential emission reduction projects above.

Emissions of ROG, NO_X, PM_{10}, and $PM_{2.5}$ from all Project activities, as described above, were included in the incremental annual emission estimates provided in Tables 4.3-31 and 4.3-32 and were used in the formulation of the OG-ERA mitigation fee. The OG-ERA and emission reduction projects undertaken by the in-lieu fee, as described above, will mitigate for both PM_{10} and $PM_{2.5}$ emissions from Project implementation and the OG-ERA requires that all criteria pollutants be addressed, and specifically NOx, PM_{10} and $PM_{2.5}$, when projects are chosen. All projects funded by the OG-ERA require a physical project that removes a source of these criteria pollutants from the basin to offset the emissions generated by the oil and gas production over the 20 years of the Project. Emission reduction projects that cannot be funded by the OG-ERA include planning projects to address environmental justice issues, land use planning projects, infrastructure planning, updating of general or specific plans or updating of any local air monitoring plans. While all these projects are important for outreach, education, and future decision making they will not remove a source that is actually generating criteria pollutant emissions and therefore would not qualify for use of the OG-ERA funds. No such projects have been funded with OG-ERA funding to date.

Mitigation fee programs are valid even with no specific schedule for implementation. See Friends of Lagoon Valley v. City of Vacaville (2007) 154 Cal.App.4th 807, 818 (absence of specific time schedule for completing road improvements with traffic mitigation fees was not fatal). Though contemporaneous mitigation with fee collection or with emitting activities may not occur, this is typical for fee-based mitigation programs and does not affect the adequacy of the mitigation under CEQA.

The OG-ERA is anticipated to fully offset Project emissions of NO_X, PM_{10}, $PM_{2.5}$, and ROG. As explained above, many Project emissions result from construction activities, including well drilling, and these emissions are temporary. However, the emission reduction projects funded by OG-ERA fees result in the permanent shutdown of emitting equipment and the permanent removal of those emissions from the air basin. Only the first year of those emission reductions is truly counted as mitigation obtained by the OG-ERA fees, despite the fact that those reductions continue in perpetuity. Thus, the OG-ERA may result in higher emission reductions than the emissions that occur in just one year from the Project and for which mitigation fees are paid. Additionally, the conservative approach in not subtracting baseline activity levels from the total number of projected *wells in order to determine the incremental increase in emissions from the Project further contributes to the OG-ERA's ability to fully offset Project emissions.*

MM 4.3-8 (below) requires the continued implementation of the executed OG-ERA (Appendix C). This measure has been clarified for clear readability and definition of all pollutants that must be mitigated by emission reduction projects selected by the SJVAPCD to receive OG-ERA funding.

MM 4.3-8 (Clarified) For criteria emissions, not required to be offset under a District rule as described in MM 4.3-1, and for Project vehicle and other mobile source emissions, the County will enter into an emission reduction agreement with the San Joaquin Valley Air Pollution Control District, pursuant to which the Applicant shall pay fees to fully offset Project emissions of NO_X (oxides of nitrogen), ROG (reactive organic gases), PM_{10} (particulate matter of 10 microns or less in diameter) and $PM_{2.5}$ (particulate matter of 2.5 microns or less in diameter) (including as applicable mitigating for reactive organic gases by additive reductions of particulate matter of 10 microns or less in diameter) (collectively, "designated criteria emissions") to avoid any net increase in these pollutants. The air quality mitigation fee shall be paid to the County as part of the Site Plan review and approval process, and shall be used to reduce designated criteria emissions to fully offset Project emissions that are not otherwise required to be fully offset by District permit rules and regulations.

As an alternative to paying the fee, an Applicant may reduce emissions for one or more designated criteria emissions through actual reductions in air emissions from other Applicant sources, as submitted to the County and validated by the District. This Project offset requirement alternative shall be enforced by the County and verified by San Joaquin Valley Air Pollution Control District, and must be approved in advance by the San Joaquin Valley Air Pollution Control District. If a voluntary emission reduction agreement is not executed by the County and San Joaquin Valley Air Pollution Control District, then each Applicant must mitigate for the full amount of designated criteria pollutants as verified by the San Joaquin Valley Air Pollution Control District, with evidence of such District-verified offsets presented as part of the Site Plan Conformity Review application documentation.

Examples of feasible air emission reduction activities that may be funded by air quality fees paid by Applicant or proposed and implemented by the Applicant under the emission reduction agreement include, but are not limited to, the following:

a. Replacing or retrofitting diesel-powered stationary equipment such as motors on generators, pumps and wells with electric or other lower-emission engines that are not subject to Title V reductions.

b. Replacing or retrofitting diesel-powered school, transit, municipal and other community mobile sources such as buses, car fleets, and maintenance equipment, with electric or other lower-emission engines.

c. Reducing emissions from public infrastructure sources such as water and wastewater treatment and conveyance facilities, and reducing water-related emissions through water conservation and reclamation.

d. Funding lower-emission equipment and processes for local businesses, schools, non-profit and religious institutions, hospitals, city and county facilities.

While the reductions from MM 4.3-8 and the OG-ERA will offset NO_X, $PM_{10,}$ and $PM_{2.5}$ emissions to net zero, actual reductions of ROG, NO_X, $PM_{10,}$ and $PM_{2.5}$ remain impossible to certify as 100% reduced to zero. Therefore, this uncertainty and small unknown quantities remaining under CEQA make air quality impacts significant and unavoidable. However, all reasonable and feasible mitigation has been required and will reduce the air emissions as close to a "no net increase" from the current emissions over the next 21 years as is scientifically possible to quantify and confirm.

Mitigation Measures

Implement MM 4.3-1 through MM 4.3-4, as described above, and fully offset Project criteria pollutant emissions as required by MM 4.3-8 below.

Level of Significance After Mitigation

Impacts would be significant and unavoidable.

Impact 4.3-3: Expose Sensitive Receptors to Substantial Pollutant Concentrations

Health Risk Assessment

Three HRAs were completed for the Project. The HRAs evaluated the potential cancer risk and acute and chronic non-cancer risk from toxic emissions associated with well construction, drilling, completion, and oil and gas processing equipment. The first single-well HRA was conducted by the County Application Technical Committee in June 2015 (CATC 2015) and is provided in Appendix B of this SREIR. In response to comments received from the SJVAPCD, a second single-well HRA was completed in September 2015 and is provided in Appendix B of this SREIR. Finally, a multi-well HRA was completed and is provided in Appendix B of this SREIR (Multi-Well HRA). A technical memo that reviews the adequacy of the Multi-Well HRA as compared to current guidelines is also provided in Appendix B. A summary of these HRAs is provided below.

The HRAs were performed following the OEHHA, Air Toxics Hot Spots Program Risk Assessment Guidelines (OEHHA 2015). As recommended by the guidelines, the CARB Hotspots Analysis and Reporting Program, Version 2 (HARP2) (CARB 2015) was used to perform a refined HRA for potential future construction and operational emissions. HARP2 includes the following three modules: a dispersion model, an exposure/dose module, and a risk module. The dispersion model incorporates the EPA's AERMOD model and the risk model includes the latest changes made by the State of California to the risk assessment inputs.

In general, risk assessments involve four steps:

- Emissions Estimations;
- Exposure Assessments;
- Dose-response Assessments; and
- Potential Health Risk Quantification.

Emission Estimations

Emission estimates involve identifying and quantifying emissions of potential regulated toxic substances from each source. The OEHHA determines the relative toxicity of chemicals regulated by the State of California and determines whether they are carcinogenic or possibly associated with short-term or long-term non-cancer health impacts. Toxic emissions from each source were quantified.

According to the CAA, "hazardous air pollutants" include a variety of pollutants generated or emitted by industrial production activities. HAPs are also referred to as TACs under California law (pursuant to the Tanner Act of 1983, codified at Health and Safety Code Section 39650 et. seq.). The State of California determines the toxicity of each pollutant and assigns each a potency factor. Those factors are built into the HARP2 risk assessment model.

For purposes of the June 2015 Single-Well HRA, all $PM_{2.5}$ from diesel equipment associated with well drilling (including potential dust and mobile equipment) is assumed to be toxic diesel PM. For purposes of the September 2015 Single-Well HRA and the Multi-Well HRA, all PM_{10} from diesel equipment associated with well drilling is assumed to be DPM. This significantly overstates true emissions as a portion of the PM_{10} calculated included road dust and other sources of fugitive dust associated with well pad construction, well drilling, and completion that are not actually DPM.

California listed diesel exhaust or DPM as a TAC in 1998. The DPM toxicity number incorporates the cumulative health effects of all of the constituents of diesel exhaust into one risk number. DPM is the only TAC expected to be emitted from well construction and completion.

The risk from the oil processing equipment is due approximately 94% to benzene, as well as formaldehyde and PAHs. All three are byproducts of natural gas combustion. Potential health effects from these compounds are summarized here.

June 2015 and September 2015 Single-Well HRAs

Construction Emissions

For well construction, well drilling and well completion, seven phases of construction were considered. Emissions from the following seven construction phases were assumed to occur simultaneously, although these activities are unlikely to all occur concurrently:

- Land Preparation;
- Drilling Survey;
- Well Drilling;
- Well Completion;
- Well Flowline;
- Pump Unit; and
- Electrical.

Emissions from the drilling of wells to depths of 2,000 feet, 5,000 feet, and 10,000 feet were evaluated as emissions sources. According to CalGEM, only 3% of the wells drilled in Kern County in 2014 were at depths of 10,000 feet or greater. An initial year of 2015 was modeled and the final year of 2035 was modeled. For the 10,000-foot well, the year 2018 was also modeled.

Table 4.3-33: Estimated per Well Emissions used in the July 2015 and September 2015 Single-Well Health Risk Assessment Analyses

Depth Feet	Year[(a)]	Total $PM_{2.5}$[(b)] pounds	Annual $PM_{2.5}$[(c)] pounds	Days[(d)]
10,000	2015	516.89	17.23	23
10,000	2018	444	14.8	23
10,000	2035	151.83	5.06	23
5,000	2015	171.18	5.71	8
5,000	2035	35.86	1.20	8
2,000	2015	97.12	3.24	4
2,000	2035	20.42	0.68	4

Notes:
(a) 2029-2035 emissions are the same.
(b) From Vector Environmental, Inc. (Vector) Spreadsheet titled “DRL_EMISSIONS.xlsx”, worksheet “EMF”.
(c) Total emissions divided by 30 years per OEHHA’s HARP2 exposure duration requirements.
(d) From Vector spreadsheet titled “DRL_EMISSIONS.xlsx”, worksheet “MUD”.
Key:
OEHHA = California Office of Environmental Health Hazard Assessment
$PM_{2.5}$ = particulate matter less than 2.5 microns

Operational Equipment Emissions

Emissions from operational activities were evaluated separately from construction activities. Two different scenarios were evaluated: oil processing and natural gas.

Emissions from the following operational equipment (as provided by Vector) were analyzed as the operational emissions in the oil processing scenario:

- Two – 1,000 barrel (bbl) aboveground tanks;
- One – 3,000 bbl aboveground tank;
- One 10 MMBtu/hour flare;
- Truck loading rack;
- Fugitive emissions from valves, flanges, and one underground sump; and
- TEOR equipment.

Emissions from the following natural gas combustion equipment were analyzed in the natural gas scenario:

- One new 100 MMBtu/hour flare;
- One – 8 MMBtu/hour process heater;
- One – 10 MMBtu/hour boiler;
- One – 85 MMBtu/hour steam generator; and
- One – 33 megawatt cogeneration plant.

Potential toxic emissions from each of these devices are summarized in Appendix A of the HRAs, provided as Appendix B of this SREIR.

Exposure Assessment

- The exposure assessment was used to evaluate a receptors potential exposure to emissions through inhalation, ingestion, and dermal exposure. A receptor can be hypothetically exposed to a substance through several different pathways. Typically, the primary environmental exposure pathway in an HRA is direct inhalation of gaseous and particulate air pollutants. However, there is the potential for exposure via non-inhalation pathways due to the deposition of particulate pollutants (DPM) in the environment.
- Air dispersion modeling was used to estimate ground-level concentrations. The concentrations are then multiplied by the worst-case potential emission rate for each substance to obtain the corresponding ground-level concentrations. A description of the models and the assumptions used are included in the HRAs (Appendix B of this SREIR).

- Three different locations within Kern County were assessed in the June 2015 Single-Well HRA to capture various terrains, wind speed, wind direction, and other dispersion characteristics within Kern County:
  - Western Subarea – Midway Sunset Oilfield,
  - Central Subarea – No. Shafter Oilfield, and
  - Eastern Subarea – Kern River Oilfield.

The September 2015 Single-Well HRA added a fourth location in the Western Subarea, known as Derby Acres, moved the Midway Sunset location about a mile away from the original location, and moved the Kern River location about 8 miles away from the original location.

Dose-Response

The dose-response assessment describes the quantitative relationship between a human's exposure to a substance (the dose) and the incidence or occurrence of an adverse health impact (the response). For carcinogens, OEHHA has developed cancer potency factors. A cancer potency factor represents the upper-bound probability of developing cancer based on a continuous lifetime exposure. The cancer potency factor does not represent a threshold under which a person would not develop cancer, but instead is used to estimate the probability of developing cancer.

For non-carcinogenic chemicals, OEHHA has developed Recommended Exposure Limits (RELs) for acute and chronic impacts. RELs represent concentration thresholds at which no adverse noncancer health effects are anticipated. For chemicals that are not deemed by the State of California as possible carcinogens, but which may pose either short-term (acute) or other non-cancer long-term (chronic) health effects, a Hazard Index (HI) calculation of potential risk is also required by the air district and the State as part of an HRA.

Significance Thresholds

The SJVAPCD publishes CEQA significance thresholds for potential health risk from proposed projects. Currently, risks from a project that are less than the following regulatory thresholds are considered not to be significant and are, therefore, acceptable:

- Cancer risk equal to or less than 10 in one million;
- Chronic hazard index equal to or less than 1; and
- Acute hazard index equal to or less than 1.

These metrics are generally applied to the maximally exposed individual (MEI). There are separate MEIs for residential exposure (i.e., residential areas) and for worker exposure (i.e., offsite work places).

As discussed above, the HRAs were performed using the HARP2 model. The following table provides the estimated cancer risk from construction activities for the three well depths in each

Subarea according to both the June 2015 Single-Well HRA and the September 2015 Single-Well HRA.

As shown, well construction activities in the Western and Central Subareas have the highest potential risk. Risks at locations between the construction activities and the distance indicated in the table would exceed the cancer risk threshold of 10 in one million for a 10,000-foot well, and a 5,000-foot well in 2015 under the June 2015 Single-Well HRA. Under the September 2015 Single-Well HRA, only the Derby Acres location would exceed the cancer risk threshold of 10 in one million for a 15,000-foot well in 2017. Other depths were not modeled for the Derby Acres location as the setback in MM 4.3-5 of 367 feet in the Western Subarea for a 10,000-foot well would already encompass this distance.

Table 4.3-34: Potential Health Risk from Well Construction, Drilling, and Completion Emissions

Well Depth (feet)	Year	Maximum Distance from Well Site and Project Boundary to 10 in One Million Calculated Risk from June 2015 Single-Well HRA	Maximum Distance from Well Site and Project Boundary to 10 in One Million Calculated Risk from September 2015 Single-Well HRA
Western Subarea – Midway Sunset			
10,000	2015	367 feet	NA
10,000	2020	232 feet	NA
10,000	2029	82 feet	NA
5,000	2015	116 feet	NA
5,000	2029	NA	NA
2,000	2015	NA	NA
2,000	2029/2035	NA	NA
Western Subarea – Derby Acres			
15,000	2017	—	182 feet
Central Subarea			
10,000	2015	367 feet	NA
10,000	2020	232 feet	NA
10,000	2029	82 feet	NA
5,000	2015	116 feet	NA
5,000	2029	NA	NA
2,000	2015	NA	NA
2,000	2029/2035	NA	NA

Table 4.3-34: Potential Health Risk from Well Construction, Drilling, and Completion Emissions

Well Depth (feet)	Year	Maximum Distance from Well Site and Project Boundary to 10 in One Million Calculated Risk from June 2015 Single-Well HRA	Maximum Distance from Well Site and Project Boundary to 10 in One Million Calculated Risk from September 2015 Single-Well HRA
Eastern Subarea			
10,000	2015	296 feet	NA
10,000	2019	183 feet	NA
10,000	2029	NA	NA
5,000	2015	NA	NA
5,000	2029	NA	NA
2,000	2015	NA	NA
2,000	2029/2035	NA	NA

Key:
HRA = Health Risk Assessment
NA = No offsite risk greater than 10 in one million

Table 4.3-35a and 4.3-35b provide the estimated cancer risks that would be associated with operational activities in each Subarea from natural gas and oil processing equipment, respectively. Table 4.3-35b shows that the cumulative risk from oil processing equipment exceeds the threshold in each Subarea at the distances listed in the table, at distances of 478 to 701 feet from the operational activity, depending on the Subarea of Kern County.

Table 4.3-35a: Estimated Cancer Risks from Operational Emissions from Natural Gas Processing Equipment

Equipment	Risk Greater Than 10 in One Million?
1,000 bhp natural gas internal combustion engine	No
100 MMBtu/hr flare	No
85 MMBtu/hour steam generator	No
8 MMBtu/hour boiler	No
33 MW cogeneration	No
TEOR Equipment	No

Key:
bhp = brake horsepower
bbl = barrel
MMBtu/hr = million metric British thermal units per hour
MW = megawatt
TEOR = thermally enhanced oil recovery

Table 4.3-35b: Estimated Cancer Risks from Operational Emissions from Oil Processing Equipment

	Cancer Risk Distance to 10 in One Million		
Equipment	**Western Subarea**	**Central Subarea**	**Eastern Subarea**
Cumulative Risk Distances – June 2015 Single-Well HRA	701 feet	625 feet	478 feet
Cumulative Risk Distances – September 2015 Single-Well HRA	296 feet	366 feet	295 feet

Note:
Oil processing equipment includes: ~~1,000 barrel (bbl) oil tank,~~1,000 bbl oil tank, 3,000 bbl oil tank, truck loading rack, 30-foot by 30-foot underground sump, 10,000 British thermal units per hour flare, and fugitive volatile organic compounds. Emissions for gas and oil processing equipment are assumed to be the same between 2015 and 2035. Emissions "credit" for potential future emission reductions was not assumed.
Key:
bbl = barrels
HRA = health risk assessment

Table 4.3-36 provides the estimated potential acute non-cancer risk impacts that would be associated with the emissions generated by the activities of drilling, oil processing, and gas processing in each Subarea. Acute impact refers to the risk associated with short-term effects of exposure to toxic emissions. The estimated acute risks associated with drilling, oil processing, and gas processing are below the hazard index standard in each Subarea.

Table 4.3-36: Potential Acute Impacts

Equipment	**Western Subarea Acute Risk**	**Central Subarea Acute Risk**	**Eastern Subarea Acute Risk**	**Hazard Index Standard**	**Significant Risk?**
June 2015 Single-Well HRA					
Drilling Emissions	0.0098	0.0098	0.0090	1.0	No
Oil Processing Emissions	0.43	0.41	0.40	1.0	No
Gas Processing Emissions	0.88	0.88	0.89	1.0	No
September 2015 Single-Well HRA					
Drilling Emissions	0.0039	0.0098	0.0090	1.0	No
Oil and Gas Processing Emissions	0.23	0.01	0.14	1.0	No

Table 4.3-37 provides the estimated potential chronic non-cancer risk that would be associated with the emissions generated by the activities of drilling, oil processing, and gas processing in each Subarea. Chronic impact refers to the risk associated with long-term effects of exposure to toxic

emissions. The estimated acute risks associated with drilling, oil processing, and gas processing do not exceed the HI standard in each Subarea.

Table 4.3-37: Potential Chronic (Non-Cancer Risk)

Equipment	Western Subarea Chronic Risk	Central Subarea Chronic Risk	Eastern Subarea Chronic Risk	Hazard Index Standard	Significant Risk?
June 2015 Single-Well HRA					
Drilling Emissions	0.0009	0.0009	0.0008	1.0	No
Oil Processing Emissions	0.063	0.63	0.60	1.0	No
Gas Processing Emissions	0.034	0.034	0.030	1.0	No
September 2015 Single-Well HRA					
Drilling Emissions	0.003	0.006	0.002	1.0	No
Oil and Gas Processing Emissions	0.30	0.46	0.18	1.0	No

Key:
HRA = Health Risk Assessment

Single-Well HRA Results

The Single-Well HRAs show that the potential cancer risk exceeds the current CEQA significance thresholds (as of May 2015), for drilling a 10,000-foot well in any Project year, for drilling a 5,000-foot well in year 2015, and for operations of the oil processing equipment.

By 2018, due to emission reductions resulting from compliance deadlines occurring from CARB current diesel regulations, the risks associated with drilling a 5,000-foot (or less deep) well would not exceed the 10 in one million (10×10^{-6}) threshold. Therefore, the Project would exceed the current 10 in one million CEQA significance threshold for cancer risk if a 10,000-foot well is drilled, and if a 5,000-foot well is drilled for the years 2015 to 2017, assuming that the risk level in years 2016 and 2017 would be the same as in 2015.

The cancer risk from all oil processing equipment would exceed 10 in one million from the fenceline to 295 to 701 feet, depending on the Subarea and HRA assumptions. The oil processing equipment would require operating permits from the SJVAPCD (except possibly the loading rack for which there may be a Rule 2020 Exemption) and, as such, total risk from the facility would be modeled at that time. Emissions and risk from any future proposed facilities would be required to meet the Air District's risk threshold which is currently 10 in one million. Therefore, impacts would be significant.

Multi-Well HRA

The Multi-Well HRA was completed to evaluate potential cumulative health impacts associated with multiple well drilling operations occurring simultaneously. The Multi-Well HRA is included in this SREIR as Appendix B. The Multi-Well HRA was conducted using the same analysis as described above, with the exception of the following:

The Multi-Well HRA assumed that up to 48 individual 13,000-foot wells would be drilled in concentric circles around a sensitive receptor *that was assumed to be surrounded by a 300- by 300-meter fence*. Twelve wells would be 1/8 of a mile or 660 feet away from the sensitive receptor, 12 more wells would be 1/4 of a mile or 1,320 feet away, 12 more wells would be 3/4 of a mile or 3,960 feet away, and 12 more wells would be 1 mile or 5,280 feet away. At 1/4 miles from the central receptor, the well density would be approximately 0.75 wells per acre (24 wells located in 31.4 acres). Closer to the central receptor, the well density would be even greater. Each well was assumed to have a drilling mud sump with emissions conservatively assumed to have a continuous VOC release rate of 0.01 lbs. per hour and those VOCs were further assumed to contain potentially toxic components typically found in crude oil*, such as benzene*.

The Multi-Well HRA included multiple conservative assumptions, including that all receptor locations were sensitive receptors, that emissions from all seven phases of well drilling would occur simultaneously, even though these activities almost always occur sequentially, that each well would have an associated mud sump with emissions, that well re-work would occur on every well every other year, that multiple wells of 13,000 foot depth would be drilled near one sensitive receptor, despite the fact that data shows that only 3% of wells drilled in Kern County in 2012 exceeded 10,000 feet, and that all PM_{10} was toxic DPM *(assumed to be inhalable)*. *The assumption that it would even be possible to drill 48 13,000foot wells around one sensitive receptor proximate in time, given that there have historically been 4 to 12 drill rigs in Kern County at any given time between 2015 and 2020, was also a conservative assumption (Baker Hughes 2020). It would take eight rigs drilling consecutively for almost a year all in one location to drill 48 13,000-foot wells. Given that, since April 2020, there have only been three to four drill rigs operating in Kern County (Baker Hughes 2020), that this number is unlikely to increase in the near future given oil and gas production activities, and that this scenario would require all eight of the theoretical rigs to be drilling in the same place for an entire year, jettisoning drilling throughout the rest of the County, this remains a conservative assumption.*

SJVAPCD emission factors were used to calculate future exhaust levels, which include future CARB regulatory compliance deadlines related to cleaner on-road and off-road heavy-duty equipment. These emission levels are built into CARB's OFFROAD model, which was used to calculate drilling exhaust. *Emission calculations were derived from SJVAPCD, CARB and EPA-approved emission factors, including, but not limited to: the EPA's TANKS program, the EPA's AP-42: Compilation of Air Emissions Factors, and SJVAPCD regulatory limits. Flare emission factors were provided by the SJVAPCD. Diesel exhaust emission factors were provided by CARB's OFF-ROAD model.* This provided a conservative analysis of potential hazardous air pollutant emissions from Project operations.

Individual items of permitted stationary equipment that is not sited at each well, such as processing equipment, was not included in the analysis because it is not sited at each well and must undergo equipment-specific risk analysis during the SJVAPCD permitting process in order to obtain an ATC from the SJVAPCD. Including this equipment would not constitute a reasonable assumption of Project impacts and would vastly overstate risks. Well bore leakage emissions and flowback were also not considered in the HRA as both are considered to be upset conditions and thus speculative. Hydraulic fracturing, or well stimulation treatments (WST), are also not included as WSTs primarily involve adding chemicals to water and injecting them into the subsurface area. Adding chemicals to water used as part of a down-well process generally does not cause air emissions. Instead, the chemicals are underground in the wells in which they are injected. To the extent that WST does cause emissions, the vast majority result from large diesel-fired drill rigs or workover rigs (the later are used for well re-work activities on existing wells) and these emissions were accounted for in the HRA. To the extent that WST would cause air emissions separately from diesel emissions, it would most likely occur from off-gassing of WST fluids after well stimulation occurred and these emissions were included in the HRA. Thus, assuming a hydraulic or acid fracked well or a combination of such rather than a TEOR well was not necessary for the HRA analysis. Produced water disposal ponds were not considered because they are not necessarily co-located with wellheads and drilling sites.

Various compounds sometimes associated with oil and gas production (such as crystalline silica, radionuclides, radon, and trimethylsilanol) were not included in the HRA assumptions due to either their lack of emissions or the fact that they are not regulated as carcinogens in California. Equipment that is electrically powered or derives power from equipment already included in the analysis was not separately included. Nor were activities that are prohibited or considered upset conditions included as those are not part of a reasonably foreseeable assumption. The emissions scenarios were instead based on gathered data representing the most likely scenarios to occur. Exhaust temperatures and stack exhaust velocity are in line with other studies of drilling rigs (AECOM 2014). The AERMET data set was used for AERMOD modeling, as required by the SJVAPCD. The drill rigs were modeled as point sources, while the mud sumps were modeled as area sources. Together, the assumptions and modeling in the multi-well HRA resulted in a conservative assessment of potential risk from Project activities Appendix B-1 of this SREIR).

Table 4.3-38 shows the annualized construction emissions for a 13,000-foot well, including rework. *Emissions were annualized to represent a conservative assessment of potential risk. Events like well rework are likely to occur during the day, and thus annualized emissions could overstate calculated risk as nighttime meteorology is typically characterized by low wind speeds and stable atmospheric conditions, which result in high modeled concentrations.*

Table 4.3-38: Annualized 13,000-Foot, 2017 Well Drilling Emissions Used in the Multi-Well Health Risk Assessment Analysis

Source	Compound	Annual Emissions (lbs./year)
Drilling	DPM[(a)]	784.32[(b)]
Rework	DPM[(a)]	18.24[(c)]
Drilling Mud Sump[(d)]	1, 2, 4 Trimethylbenzene[(e)]	0.10
	Benzene[(e)]	0.48
	Cyclohexane[(e)]	0.10
	Ethylbenzene[(e)]	0.10
	n-Hexane[(e)]	4.32
	Toluene[(e)]	0.48
	Xylenes[(e)]	0.48
	Hydrogen Sulfide[(f)]	0.10

Notes:
(a) PM_{10} emissions were from Vector Environmental, Inc. (February 2015). All particulate matter less than 10 microns was assumed to be DPM.
(b) Annualized emissions based on a 70-year exposure.
(c) 500 horsepower Tier 2 diesel engine operating every other year for nine days, 30 minutes per day, annualized.
(d) Drilling mud emissions were assumed to occur one day per year for 70 years. Actual drilling mud emissions from a 13,000-foot well would occur one time only for 43 days.
(e) From San Joaquin Valley Air Pollution Control District Website: Oilfield Equipment Light Crude Oil Fugitives.
(f) Based on 100 parts per million by volume H_2S.
Key:
DPM = diesel particulate matter
lbs. = pounds

The Multi-Well HRA found that the health risk with this conservative multi-well scenario would be 9.3 in one million, below the SJVAPCD threshold of 20 in 1 million. It should be noted that the primary driver for risk in the HRA is days of drilling, not well depth, and that these conditions are not related in a linear fashion.

Multi-pathway exposure was not utilized, nor were chronic and acute impacts considered as approximately 99.9 percent of the risk associated with the multi-well scenario comes from DPM and thus inhalation is the dominate pathway for exposure. As shown by the single-well HRAs above, even with the inclusion of extensive production equipment, including engines, a cogeneration facility, several tanks, a flare, and additional equipment, both the acute and chronic (non-cancer) impacts are well below the regulatory threshold.

The information in this chapter regarding the current SJVAPCD $PM_{2.5}$ plans and current attainment status does not change the analysis for any of the 2015 HRAs described above. In the June 2015

Single-Well HRA, all $PM_{2.5}$ was assumed to be DPM, while in the September 2015 Single-Well HRA and the Multi-Well HRA all PM_{10} was assumed to be DPM. Since these assumptions are conservative and DPM represents the overwhelming health risk from the Project, no updated analysis is required. In addition, the SJVAPCD's attainment status does not affect any assumptions related to the HRAs as the HRA modeling is based on Project emissions and Project emissions are unrelated to current SJVAB attainment status. The Multi-Well HRA specifically is very conservative, as it assumes 48 13,000-foot wells (a well depth deeper than the vast majority of wells in Kern County) within a mile of one sensitive receptor, in addition to the other conservative assumptions explained above.

Since 2015, minor updates and changes have been made to HRA methodology and modeling.~~, *but these also do not affect the analysis in the 2015 HRAs conducted for the Project (SREIR Appendix B)*~~. A memorandum from the HRA consultant explains that minor updates have been made to AERMOD and HARP2, but~~,~~ that none of these minor updates would affect the assumptions or conclusions in the *2015* HRAs *conducted for the Project (SREIR Appendix B)*. Further, while OEHHA has made some changes to its HRA guidance, OEHHA has not modified or revised the toxicity factors for any of the chemicals used in the 2015 HRAs (DPM, benzene, cyclohexane, ethylbenzene, n-hexane, toluene, xylenes, 1,2,4 trimethylbenzene, and hydrogen sulfide). Thus, the 2015 HRAs remain valid for purposes of the SREIR.

Valley Fever

The *Coccidioides immitis* fungus spores in soil, which are responsible for transmitting the Valley Fever, can disperse in the air when the soil is disturbed during construction activities, and then can be inhaled into the lungs. Onsite construction workers potentially could be exposed to Valley Fever from fugitive dust generated during construction of the proposed Project, notably during excavation, grading, and other earthmoving activities. Construction activities within the Project Area are subject to SJVAPCD Regulation VIII (Fugitive PM_{10} Prohibition). Regulation VIII is intended to reduce ambient concentrations of PM_{10} by requiring actions to prevent, reduce, or mitigate anthropogenic fugitive dust emissions. By reducing fugitive dust emissions, Regulation VIII reduces potential exposure to Valley Fever. Since current long-term residents typically already have been exposed to and have developed immunity to Valley Fever, construction activities are not expected to add significantly to exposure of offsite residents to the fungus.

Impacts are potentially significant because cancer risk levels exceed thresholds at locations where receptors are located closer than 200 meters from a well. In addition, the risks associated with exposure to Valley Fever are significant without mitigation.

COVID-19

COVID-19 is an infectious disease caused by the SARS-CoV-2 strain of coronavirus, a group of related RNA viruses that cause diseases in mammals and birds. COVID-19 can cause fever, cough, fatigue, shortness of breath, and loss of smell and taste. While the majority of cases result in mild symptoms, some progress to acute respiratory distress syndrome, multi-organ failure, septic shock, and blood clots. COVID-19 primarily spreads through close contact with an infected person and via respiratory droplets produced from coughs or sneezes. *A recent study found that* a small increase in long-term exposure to $PM_{2.5}$ ~~has been found to~~ *may* lead to an increase in the death rate of COVID-19 (Harvard School of Public Health 2020). *The study suggests that long-term exposure to $PM_{2.5}$ is associated with higher COVID-19 mortality rates, even after adjustment for a wide range of socioeconomic, demographic, weather, behavioral, epidemic stage, and healthcare-related confounders.* Long-term exposure to $PM_{2.5}$ emissions may also add to the potential susceptibility for COVID-19. *People of color may also have a higher risk of getting sick or dying from COVID-19 (California Department of Public Health 2020) and may live in areas already burdened by air pollution (NRDC 2014).* Onsite workers and residents near Project activities potentially could be exposed to increased levels of $PM_{2.5}$ from Project activities due to the emissions of $PM_{2.5}$ from the Project, as described in Impact 4.3-2 above. $PM_{2.5}$ emissions from diesel emissions during construction and operation of the proposed Project, could increase susceptibility to COVID-19.

Impacts are potentially significant because the Project will increase $PM_{2.5}$ emissions. While $PM_{2.5}$ emissions from Project implementation will be reduced as much as is feasible with implementation of MM 4.3-1 through MM 4.3-4 and MM 4.3-8, this impact cannot be mitigated to a level of less than significant as there is currently no vaccine for COVID-19. Thus, impacts remain significant and unavoidable even with all feasible mitigation.

Premature Birth

A recent study has found limited evidence that exposure to oil and gas well sites in the first and second trimesters is associated with increased odds of spontaneous preterm birth at 20 to 31 weeks (Gonzalez et al. 2020). The study analyzed preterm births in three categories based on gestational age: 20 to 27 weeks, 28 to 31 weeks, and 32 to 36 weeks. The exposure was assumed from all wells within a 10 km radius of the maternal residence. While the study found that exposure to oil and gas well sites was associated with increased odds of spontaneous preterm birth, this association was confined to women who were Hispanic and non-Hispanic Black, and those with 12 or fewer years of educational attainment. The study also explains that residents near well sites may be exposed to a range of environmental and social stressors and that the authors were unable to evaluate which factors confer risk. The study was not able to account for other sources of ambient air pollution in the study region, nor did it account for other contributors to preterm birth besides air pollution (such as *levels of* prenatal care).

Another study completed a systematic review of prior research studies and assessed the associations between exposure to $PM_{2.5}$, ozone, and heat with preterm birth, low birth weight, and stillbirth (Bekkar et al. 2020). The review did not conduct a meta-analysis, but presented the primary findings in summary evidence tables for each key question and tabulated the preponderance of evidence that found significant associations. The study found that of 48 studies regarding exposure to $PM_{2.5}$ and ozone, 84% found a significant association between exposure to air pollutants and adverse birth outcomes. Of 10 studies examining the association between heat exposure and obstetrical outcomes, 90% found a significant association between exposure to heat during pregnancy and adverse birth outcomes. Of the 11 studies analyzing $PM_{2.5}$ whole-pregnancy exposure, the risk increased by a median of 11.5% (range, 2% to 19%). Of the four studies analyzing ozone whole-pregnancy exposure, two found an increased risk from 3% to 9.6%. Five studies showed no association between $PM_{2.5}$ and preterm birth, measuring exposures during the whole pregnancy, by trimester, or by month of birth; while three studies showed no associations with low birth weight.

The subpopulations at highest risk in the studies were persons with asthma and minority groups, especially black mothers. Eight studies noted higher risk for black mothers and 13 studies reported the association of racial/ethnic disparities with increased risk of low birth rate. Two studies noted higher risk for preterm birth among patients with asthma and Hispanic mothers. Finally, three studies noted an association of lower socioeconomic status or living in older homes, near roadways, or in urban cores with increased risk. The study explains that accurate comparisons of risk were limited in study design, exposure measurement, population demographics, and seasonality.

MM 4.3-6 has been clarified as follows.

MM 4.3-6 *The following measures shall be implemented to address Valley Fever and pandemics:*

A. Applicants shall include in their Worker Environmental Awareness Program information on how to recognize the symptoms of Valley Fever and to promptly report suspected symptoms of work-related Valley Fever to a supervisor. *A Valley Fever informational handout shall be provided to all onsite construction personnel. The handout shall, at a minimum, provide information regarding the symptoms, health effects, preventative measures, and treatment. Additional information and handouts can be obtained by contacting the Kern County Public Health Services Department*. ~~*Workers exposed to fugitive dust shall be provided with the option of using a filter fitted over their nose and mouth, secured by a strap, including training for mask practices as required by Cal OSHA regulations*~~ *Onsite personnel shall be trained on the proper use of personal protective equipment, including respiratory equipment. National Institute for Occupational Safety and Health (NIOSH)-approved respirators shall be provided to onsite personal, upon request.* as part of the Worker Environmental Awareness Training Program.

B. Applicants shall pay a $25 fee per individual well on Oil and Gas Conformity Reviews to be used by the Kern County Public Health Department for the specific purposes of continued Valley Fever education and outreach.

C. Applicants shall implement all orders related to the COVID-19 pandemic or any other pandemic mandated by the Kern County Public Health Services Department on well sites and related to worker safety.

Impacts are potentially significant because the Project will increase $PM_{2.5}$ emissions. $PM_{2.5}$ emissions from Project implementation will be reduced as feasible with implementation of MM 4.3-1 through MM 4.3-4 and MM 4.3-8; however, the risks associated with exposure to $PM_{2.5}$ are significant without mitigation. *The list of distance triggers for mitigation in MM 4.3-5 and other distance triggers and setbacks required by the SREIR for sensitive receptors for other impacts are summarized in Section 4.12. All well sites are permitted with longitude and latitude data that must be the same between the Oil and Gas Conformity Review and the CalGEM permit. In addition,*

<u>this mitigation measure requires the longitude and latitude for the closest sensitive receptor property line as well. Such data can be confirmed immediately at the site with normal GPS on any electronic device. Therefore, the location of the well and the location of the sensitive receptor is fixed and enforceable for the required mitigation distance and not merely based on visual mapping calculations.</u>

Mitigation Measures

MM 4.3-5 The Site Plan Application for an Oil and Gas Conformity Review shall include a Site Vicinity Figure showing the location of any sensitive receptor(s) within 4,000 feet of the construction site (potential impact area) for the proposed new well or other ancillary facility or equipment (excluding pipelines).

a. If there are no sensitive receptors within this potential impact area, then no construction mitigation measures shall be required and the statement shall be placed as a note on the site plan.

b. The well site and nearest property line of a sensitive receptor shall be permitted using both maps and coordinates on the map. If there are sensitive receptors within the potential impact area, then additional information must be provided showing the distance from the closest edge of the well pad to the property line of the nearest sensitive receptor. The minimum distances shall be as follow:

Well Depth (Feet)	Minimum Mitigation Trigger Distance from Well Site to Adjacent Property Line of an Existing Sensitive Receptor (Feet)
Western Subarea	
10,000	367
5,000	116
2,000	NA
Central Subarea	
10,000	367
5,000	116
2,000	NA
Eastern Subarea	
10,000	296
5,000	NA
2,000	NA

c. If the above distances cannot be met, and for existing wells that are subject to an Oil and Gas Conformity Review for redrilling or other permitted activities, the Applicant shall provide a site-specific risk assessment to the San Joaquin Valley Air Pollution Control District, which shall include implementation of one or more of the following risk minimization measures, or other such measures that are demonstrated by the Applicant to the San Joaquin Valley Air Pollution Control District, to achieve a level of risk less than the threshold risk level. Written confirmation shall be provided from the San Joaquin Valley Air Pollution Control District that the activity that is the subject of the application will not exceed the risk threshold. The following is a list of accepted risk minimization measures that shall be considered for inclusion by the San Joaquin Valley Air Pollution Control District:

1. Placement of engines in the potential impact area away from the sensitive receptors.
2. Utilize directional drilling to locate rig away further from the sensitive receptor(s).
3. Use of late-model engines, low-emission diesel products, alternative cleaner fuels (e.g., natural gas or liquefied petroleum gas), engine retrofit technology, add-on devices such as diesel particulate filters or oxidation catalyst, and/or other options as such become available to reduce emissions from off-road and other equipment.
4. Utilize electricity line power if available or deploy mobile solar panels with batteries for electricity.
5. Shutdown all equipment when not in use, and otherwise minimize engine idling by limiting idling to 15 minutes.
6. Use of automatic rigs.
7. Written confirmation from the identified sensitive receptor or receptors that the residents, business, church, or school agree to voluntary relocation or restrictions on receptor activities for the duration of construction activities with a specific timeframe for completion and details of any agreement

MM 4.3-6 The following measures shall be implemented to address Valley Fever and pandemics:

A. Applicants shall include in their Worker Environmental Awareness Program information on how to recognize the symptoms of Valley Fever and to promptly report suspected symptoms of work-related Valley Fever to a supervisor. A Valley Fever informational handout shall be provided to all onsite construction personnel. The handout shall, at a minimum, provide information regarding the symptoms, health effects, preventative measures, and treatment. Additional information and handouts can be obtained by contacting the Kern County Public Health Services Department.

Onsite personnel shall be trained on the proper use of personal protective equipment, including respiratory equipment. National Institute for Occupational Safety and Health (NIOSH)-approved respirators shall be provided to onsite personal, upon request. as part of the Worker Environmental Awareness Training Program.

B. Applicants shall pay a $25 fee per individual well on Oil and Gas Conformity Reviews to be used by the Kern County Public Health Services Department for the specific purposes of continued Valley Fever education and outreach.

C. Applicants shall implement all orders related to the COVID-19 pandemic or any other pandemic mandated by Kern County Public Health on well sites and related to worker safety.

Level of Significance After Mitigation

Impacts would be significant and unavoidable.

Impact 4.3-4: Result in Other Emissions Such as Those Leading to Odors Adversely Affecting a Substantial Number of People

The analysis of the potential of the Project to create other emissions leading to odors that would adversely affect a substantial number of people was assessed in t Chapter 4.3 of the 2015 FEIR (SREIR Volume 3). The following mitigation measure from the 2015 FEIR continues to be required:

Mitigation Measures

MM 4.3-7 Applicant shall submit an Odor Complaint Management Plan to the County prior to receiving its first Site Plan conformity review approval. The Plan shall include a designated contact for odor complaints, creation of a log for odor complaints, and protocol for handling odor complaints. The Odor log and report files shall be available for public review upon request.

Level of Significance After Mitigation

Impacts would be significant and unavoidable.

4.3.5 Cumulative Setting, Impacts, and Mitigation Measures

Cumulative Setting

The regional plans and projections evaluated in this cumulative analysis are described in Section 3.7, Cumulative Projects, of this SREIR. Implementation of these plans and any projects associated with these plans would be required to comply with the goals, policies, and implementation measures of applicable federal and local laws and land use standards imposed by the respective jurisdictions within with each related project is located. This includes the possibility of being required to undergo environmental review, in compliance with the requirements of CEQA and/or the National Environmental Policy Act (NEPA). Should potential impacts to air quality be identified, appropriate mitigation would be prescribed.

Impact 4.3-5: Result in Other Cumulatively Considerable Air Quality Impacts

As discussed above in Impact 4.3-2, by its very nature, air pollution is largely a cumulative impact and the potential for the Project's emissions to cause a cumulatively considerable net increase of criteria pollutants for which the SJVAPCD is nonattainment is discussed in Impact 4.3-2. However, the Kern County Air Quality Assessment Guidelines further require the cumulative air quality impact assessment to include consideration of the following issues:

- Consistency with Existing Air Quality Plans. Discuss the Project in relation to Kern COG conformity and traffic analysis zones. Quantify emissions from similar projects and evaluate consistency with the applicable attainment plan.
- Localized Impacts. Assess the cumulative emissions impact associated with the proposed Project, in conjunction with approved and proposed projects located within a 1- and 6-mile radius of the proposed Project.
- Air Basin Emissions Analysis. Compare emissions from the proposed Project to emissions within the SJVAB and the Kern County portion of the SJVAB.

Consistency with Existing Air Quality Plans.

The Kern COG 2018 RTP is a 24-year plan to set regional transportation goals, policies, and actions intended to guide development of the planned transportation systems in Kern County (FHWA 2018). The Kern COG is a federally designated Metropolitan Planning Organization (MPO) and a state designated Regional Transportation Planning Agency (RTPA). The implementation of the RTP, in conjunction with the Project, was used to assess cumulative effects that could impact consistency with applicable attainment plans. The Program EIR for the RTP analyzed potential impacts of the multiple modes of transportation including:

- Transit/rail/high speed rail;
- Operational improvements – high-occupancy vehicle lanes/ramp metering;
- Pedestrian complete streets and bicycle improvements;
- Local streets and roads;
- Major highway improvements; and
- Freight rail.

A complete list of these projects, the Constrained Program of Projects, is available in the RTP. The RTP's air quality modeling forecast showed that by 2042 the NO_X precursor component to $PM_{2.5}$ would increase unless actions were taken. As a result, the plan focused on new strategies such as improving transit, bike, walk, and housing options to achieve and maintain the federal air quality standards and the new state climate change goals. Planned improvements in the RTP have undergone air quality conformity analyses to ensure that they would comply with state and federal air quality rules. As a result, it was determined that implementation of RTP would not delay attainment of federal air quality standards in the SIPs for air quality.

In contrast, the construction and operational activities of oil and gas activities that would be authorized under this Project would result in an increase of criteria pollutants (NO_X, VOC, CO, PM_{10}, and $PM_{2.5}$) in excess of the recommended criteria pollutant significance threshold adopted by the SJVAPCD Board.

Both the RTP and the Project would be consistent with the applicable air quality plans.

Localized Impacts

Efforts to reduce emissions in the Kern region that have been conducted since the early 1990s at the national, state, regional, and local entities since the early 1990s are presented in Table 4.3-39. The agencies involved are the EPA, U.S. Department of Energy, Federal Highway Administration, Federal Transit Administration, CARB, California Department of Transportation, California Energy Commission, SJVAPCD, Eastern Kern APCD, and Kern COG and its local member agencies.

Table 4.3-39: Programs Designed to Reduce Air Pollutant Emissions

Level	Program
National	Corporate Average Fuel Economy (CAFÉ) Standards Fuel Pricing Locomotive Idling Reduction Locomotive Replacement or Repowering Transportation Construction Equipment Reductions
State	AB 118 – Air Quality Improvement Program AB 2766 – Motor Vehicle Fee Program CalStart Cap and Trade Program Clean Diesel Clean Vehicle Rebate Project High-Occupancy Vehicle Facilities Incident management/Kern 511 Traveler Information Inspection & Maintenance Programs Moyer Program Park-and-Ride Facilities Shifting/Separation Freight Movements Signal Synchronization and Roadway Intersection Improvements
Regional	CalVans Vanpool Program Commute Kern TDM Programs/Incentives Diesel Engine Retrofits Incentive Program Drive Clean Rebate Program IdleAIR Idling Reduction Facilities Project Clean Air (PCA)

Table 4.3-39: Programs Designed to Reduce Air Pollutant Emissions

Level	Program
	REMOVE II Programs Retirement/Replacement of Heavy-Duty Trucks Incentives Program Rule 8061 (SJVAPCD) Unpaved Road Dust Mitigation Rule 9310 (SJVAPCD) School Bus Fleets: Retirement/Replacement of Buses Rule 9410 (SJVAPCD) Employer-Based Trips Reduction (eTRIP) Rule 9510 (SJVAPCD) Indirect Source Review: Infill Incentive Zone Transportation Impact Fee Land Use Strategies. Valley Clean Air Now (CAN)
Local	Bicycle/Pedestrian Projects and Programs GET Online Trip Planner Transit Marketing, Information, and Amenities New/Expanded/Increased Transit Services Road Paving & Street Sweeping

Key:
SJVAPCD = San Joaquin Valley Air Pollution Control District

As explained in Impact 4.3-2 above, the construction and operational activities of oil and gas activities that would be authorized under this Project would result in a considerable net increase of the following criteria pollutants NO_X, VOC, CO, PM_{10}, and $PM_{2.5}$, in excess of the recommended criteria pollutant significance threshold adopted by the SJVAPCD Board.

Emissions associated with the implementation of the Project would not be counterbalanced by the above efforts to reduce emissions undertaken at the State and local levels, as well as the air quality improvement goals stated in the 2018 RTP. Therefore, the contribution of Project-related impacts on air quality would be potentially significant.

Air Basin Emissions Analysis

Operational emissions for the proposed Project were compared to emissions of the entire SJVAB and the Kern County portion of the SJVAB, to assess the Project’s contribution to cumulative air quality impacts. The SJVAB and Kern County emissions analyses utilize data from the CARB’s California Emissions Projection Analysis Model (CEPAM). CEPAM reflects emission projections to the year 2035 by summary category based on a 2012 base year. Forecasts reflect both anticipated growth and controls, as updated by CARB (CARB 2013b). The emissions analysis is presented in Table 4.3-40.

Table 4.3-40: Comparison of 2035 Emission Projections – Proposed Project, Kern County, and San Joaquin Valley Air Basin

Emissions Source	Emissions (Tons/Year)				
	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$
Project Emissions					
Permitted Operation	3,279.85	5,048.92	629.53	1,490.73	1,490.73
Permitted Construction	410.44	244.77	0.34	30.02	26.72
Non-permitted	5,169.75	11,428.56	16.89	1,267.14	257.93
Total Operational Project Emissions	8,860.04	16,722.25	646.76	2,787.89	1,775.38
Kern County and SJVAB Emissions					
San Joaquin Valley Air Basin	60,151.27	389,879.13	5,382.66	114,641.39	38,758.26
Kern County Portion of SJVAB	12,671.34	42,887.14	668.32	14,641.98	4,389.49
Analytical Results					
Kern County Percent of SJVAB	21.07%	11.00%	12.42%	12.77%	11.33%
Proposed Project Percent of SJVAB	14.73%	4.29%	12.02%	2.43%	4.58%
Proposed Project Percent of Kern County Portion of SJVAB	69.92%	38.99%	96.77%	19.04%	40.45%

Key:
CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns
$PM_{2.5}$ = particulate matter less than 2.5 microns
SJVAB San Joaquin Valley Air Basin
SO_2 = sulfur dioxide

As shown in Table 4.3-40, emissions sources in Kern County contribute between 11% and 21% of criteria pollutant emissions in the SJVAB. The Project would contribute between 2% and 14% of these pollutants in the SJVAB or between 19% and 97% of Kern County's contribution. This analysis indicates that most SO_2 emissions in Kern County would originate from oil and gas activities and the majority of NO_X emissions. Therefore, the proposed Project would have a cumulatively significant contribution of criteria pollutant (NO_X, PM_{10}, $PM_{2.5}$, CO, and SO_2) emissions to the Kern County portion of the SJVAB.

Mitigation Measures

Implement MM 4.3-1 through MM 4.3-7, as described above.

MM 4.3-8 For criteria emissions, not required to be offset under a District rule as described in MM 4.3-1, and for Project vehicle and other mobile source emissions, the County will enter into an emission reduction agreement with the San Joaquin

Valley Air Pollution Control District, pursuant to which the Applicant shall pay fees to fully offset Project emissions of NO_X (oxides of nitrogen), ROG (reactive organic gases), PM_{10} (particulate matter of 10 microns or less in diameter), and $PM_{2.5}$ (particulate matter of 2.5 microns or less in diameter) (including as applicable mitigating for reactive organic gases by additive reductions of particulate matter of 10 microns or less in diameter) (collectively, “designated criteria emissions”) to avoid any net increase in these pollutants. The air quality mitigation fee shall be paid to the County as part of the Site Plan review and approval process, and shall be used to reduce designated criteria emissions to fully offset Project emissions that are not otherwise required to be fully offset by District permit rules and regulations.

As an alternative to paying the fee, an Applicant may reduce emissions for one or more designated criteria emissions through actual reductions in air emissions from other Applicant sources, as submitted to the County and validated by the District. This Project offset requirement alternative shall be enforced by the County and verified by San Joaquin Valley Air Pollution Control District, and must be approved in advance by the San Joaquin Valley Air Pollution Control District. If a voluntary emission reduction agreement is not executed by the County and San Joaquin Valley Air Pollution Control District, then each Applicant must mitigate for the full amount of designated criteria pollutants as verified by the San Joaquin Valley Air Pollution Control District, with evidence of such District-verified offsets presented as part of the Site Plan Conformity Review application documentation.

Examples of feasible air emission reduction activities that may be funded by air quality fees paid by Applicant or proposed and implemented by the Applicant under the emission reduction agreement include, but are not limited to, the following:

A. Replacing or retrofitting diesel-powered stationary equipment such as motors on generators, pumps and wells with electric or other lower-emission engines that are not subject to Title V reductions.

B. Replacing or retrofitting diesel-powered school, transit, municipal and other community mobile sources such as buses, car fleets, and maintenance equipment, with electric or other lower-emission engines.

C. C Reducing emissions from public infrastructure sources such as water and wastewater treatment and conveyance facilities, and reducing water-related emissions through water conservation and reclamation.

D. Funding lower-emission equipment and processes for local businesses, schools, non-profit and religious institutions, hospitals, city and county facilities.

Level of Significance After Mitigation

Impacts would be significant and unavoidable.

Feasible and Reasonable Mitigation Analysis

A discussion of suggested mitigation for the 2015 FEIR that was identified, considered, and rejected is provided in Chapter 4.3, Air Quality, of the 2015 FEIR (SREIR Volume 3).

Section 4.9

Hydrology and Water Quality

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Section 4.9
Hydrology and Water Quality

4.9.1 Introduction: Purpose/Scope

This section of the Supplemental Recirculated Environmental Impact Report, (*October 2020)* (SREIR) describes the affected environment and regulatory setting for hydrology and water resources in relation to groundwater supply and the implementation of the Sustainable Groundwater Management Act (SGMA) informed in part by the Supplemental Water Supply Baseline Technical Report (2020) (see Appendix D) and Section 4.17, Utilities and Service Systems in this SREIR. This section also describes the impacts to hydrology, water resources in relation to groundwater supply, and the implementation of the SGMA that would result from implementation of the Amendment to Chapter 19.98 (Oil and Gas Production) and related ordinance amendments to the Kern County Zoning Ordinance, and future development of oil and gas resources pursuant to the Amended Ordinance (Project), and mitigation measures that would reduce these impacts, if necessary. *Except where specifically noted, all underlined and italicized text indicates additions, and italicized strikethrough text indicates deletions from the SREIR (August 2020). Non italicized underlined and strikethrough text is the same as in the SREIR (August 2020).*

4.9.2 Environmental Setting

Kern County is California's third largest county, encompassing 8,202 square miles at the southern end of the Central Valley. The 3,700-square-mile Project Area is defined on Figure 3-1 in Chapter 3, Project Description, and is predominantly located in the western portion of the County in the San Joaquin Valley bounded by Kings and Tulare counties to the north; Santa Barbara and San Luis Obispo counties to the west; the Tehachapi Mountains and the Sierra Nevada Mountains to east; and the northern boundary of the Los Padres National Forest to the south.

The environmental setting section describes the current hydrology, hydrogeology, and water quality within the Project Area, including the primary watersheds and surface water and groundwater quality data. In general, the Project Area includes most of the San Joaquin Valley floor within Kern County up to an elevation of 2,000 feet. The Project Area is described in detail in Chapter 3, Project Description, of this Supplemental Recirculated Environmental Impact Report (SREIR). Additional information concerning current oil and gas production conditions in Kern County, including the adverse effects of falling global oil prices, recent state regulatory initiatives, the coronavirus pandemic on the industry, and County employment and fiscal conditions, is provided in Section 4.17.2, Utilities and Service Systems, Environmental Setting.

Climate

The Project Area is characterized by low rainfall. On average, the valley floor receives 8.32 inches of precipitation per year, most of which falls between November and April (See Appendix T-1 of the 2015 FEIR). Average temperatures are relatively high and total evaporation exceeds total precipitation. Winter is generally mild but an occasional freeze does occur and may cause substantial agricultural damage. The majority of rainfall occurs between January and March. Summers are characterized as dry with high temperatures and low humidity. Average high temperatures range from 57.4 degrees Fahrenheit (°F) in January to 98.6°F in July. Average low temperatures range from 38.5°F in December and January to 69.2°F in July (Western Regional Climate Center 2015).

A "water year" in California runs from September 30 to October 1 of the following year. California typically receives 50% of its precipitation in the months of December, January, and February in the form of snow in the Sierras. The snowpack in the Sierras typically stores water throughout the winter months and then releases it beginning in the spring.

Topography and Hydrology

The major topographic feature in the Project Area is the southern San Joaquin Valley, where the topography is generally flat. Steeper, mountainous topography is present in the Sierra Nevada Mountains to the east, the San Emigdio and Tehachapi Mountains to the south, and the Coast Range Mountains to the west.

The Project Area is located within the Tulare Lake Basin. The Tulare Lake Basin comprises the drainage area of the San Joaquin Valley south of the San Joaquin River and encompasses 17,650 square miles. The Department of Water Resources (DWR) periodically publishes maps and information regarding specific groundwater basins within California (DWR 2006). The DWR has identified several distinct groundwater basins in the Tulare Lake Basin, and there are seven watershed management areas or subbasins in the Southern San Joaquin Valley: Kings, Westside, Pleasant Valley, Kaweah, Tulare Lake, Tule, and Kern County. Each area is defined by the DWR as a designated groundwater basin (Figure 4.9-1). As discussed below, in 2016 the DWR approved a basin boundary modification under the SGMA that created a new White Wolf subbasin in the southern portion of the Project Area.

The natural hydrology of the Tulare Lake Basin has been extensively modified over the last 150 years by irrigation, flood control, and land reclamation. Dams and reservoirs have been constructed on all of the large rivers that drain into the basin for flood control, water supply, and hydroelectric generation. State, federal, local, and privately owned water conveyance facilities, such as aqueducts, pipelines, ditches, and canals, have also been constructed throughout the region to facilitate the movement of water into and out of the Tulare Lake Basin (EPA 2007).

The Kern River is the southernmost of the four major rivers in the Tulare Lake Basin and is the major surface water feature in the Kern River Basin, flowing from the Sierra Nevadas in the northeast to the Central Valley in the southwest (Figure 4.9-2). The riverbed extends through urban Bakersfield and is typically dry except during storm events and under wet hydrologic conditions when water is released upstream from Lake Isabella for flood management or local water banking purposes. Lake Isabella was created by a dam completed by the U.S. Army Corps of Engineers (USACE) in 1953. The Lake Isabella dam consists of the main dam and an auxiliary dam, which are located 2,000 feet apart. The dam is 33 miles east of the valley floor at the junction of the mainstem and south fork of the Kern River. The main earthfill dam is 185 feet high and 1,725 feet long, while the auxiliary earthfill structure is 100 feet high and 3,275 feet long. The gross storage capacity of both dams is 568,100 acre-feet (AF). The total capacity may be operated to control snowmelt floods. As discussed below, the dam is being managed by the USACE to reduce potential structural failure risks during an ongoing safety modification program that is scheduled to be completed in 2022.

From the Lake Isabella dam, the Kern River flows southwest until it emerges from a deep canyon northeast of Bakersfield. Water flowing from the canyon is diverted into canals by several weirs for use in the city of Bakersfield. During wetter conditions, surface water is released downstream for groundwater recharge operations. Depending on the amount and timing of rainfall and snowmelt, surface water from the Kern River that is not diverted or used for groundwater recharge may ultimately flow into the Buena Vista lakebed, the Kern River Intertie, and the California Aqueduct, or north toward the historical Tulare Lake Basin via the flood canals. The westerly portions of the Kern River, and several of the diversion, recharge, and flood facilities that capture or convey river flows, are located within the Project Area.

Poso Creek is located to the north of the Kern River and intermittently conveys rainfall and snowmelt from the Greenhorn Mountains to the valley floor. The creek flows west through portions of the Project Area and terminates at the federally owned Kern National Wildlife Refuge in the northwest portion of the County. The primary constructed water conveyance facilities in and near the Project Area are: (1) federally owned and operated facilities associated with the Central Valley Project (CVP), including the Friant-Kern Canal, which transports water from Sierra Nevada streams, the Sacramento Delta, and other sources to Kern County; and (2) facilities associated with the California owned and operated State Water Project (SWP), including portions of the California Aqueduct, which transport water south to Kern County and other locations from the Sacramento Delta. Major groundwater recharge and storage facilities include the 30-square-mile Kern Water Bank, owned and operated by the Kern Water Bank Authority, the Pioneer Project, owned by the Kern County Water Agency (KCWA), and storage and banking facilities that are owned and operated by several incorporated water districts in the Project Area.

Hydrogeology

The San Joaquin Valley is filled with thousands of feet of marine and continental sediments of Tertiary and Quaternary age derived from the surrounding Sierra Nevada Range and Coast Ranges, and their southern extensions. The sediment thickness increases from the valley margins toward the center. The sequence of sediments forming the basin is asymmetrical, with the thickest sediments occurring along the western side of the valley where up to 30,000 feet of sediments are found in the southwestern portion of Kern County (Page 1986).

Figure 4.9-3 provides the general geologic map for the Project Area. Two structural blocks, the Sierra Nevada Range on the east and the Coast Ranges on the west, have contributed mineralogically-distinct sediments that interfinger in the subsurface (Bartow and McDougall 1984; Bartow 1991; Page 1986; Wood and Dale 1964). The valley floor is underlain by coalescing

Quaternary alluvial fans that have formed along the mountain fronts, resulting in heterogeneous and discontinuous lenses of gravels and sands with increasing silt and clay content toward the center of the basin. The metamorphic and igneous rocks of the Sierra Nevada Batholith are exposed to the east. To the west are the faulted and folded Tertiary-aged sediments that comprise the Coast Ranges (shown as Pliocene, Miocene, Oligocene, Eocene and Paleocene sediments on Figure 4.9-3). Along the southern boundary, the metamorphic and igneous rocks underlie the Tehachapi Mountains (Sierra Nevada block) whereas faulted and folded sedimentary rocks underlie the San Emigdio Mountains (Coast Ranges block).

Basin sedimentation in the southern San Joaquin Valley began in the Jurassic Period, with the erosion of the rising Sierra Nevadas in the east. Sediments were deposited onto the shelf edge of a shallow sea. Because the Coast Ranges orogeny had not yet begun, lands to the west were open to the ocean. Deposits accumulated in the deeper water to the west, resulting in the very thick Franciscan Formation that was later uplifted, forming the Coast Ranges. Deposition proceeded throughout the Mesozoic Era, which is represented by more continuous units and an absence of deformation (Wood and Dale 1964; Croft 1972).

Tectonic activity associated with the uplift of the Coast Ranges began in the Tertiary Period and resulted in folding and faulting of sediments along the west side and a deepening of the valley floor. Thick sequences of marine sediments were deposited as the Coast Ranges orogeny continued. By the late Tertiary Period (Pliocene Epoch), the mountains had cut off the connection to the sea and marine waters had been drained from the valley. As deposition continued, non-marine (continental) sediments were deposited across the valley (Bartow and McDougall 1984; Bartow 1991).

The Pleistocene Epoch was dominated by brackish and freshwater lakes resulting in thick deposits of clay, as represented throughout the upper Tulare Formation. These include the widespread Corcoran Clay, which has been mapped over much of the San Joaquin Valley, and its equivalents, which have been correlated to clays beneath the Kern and Buena Vista dry lake beds in the southern Project Area as well as the Tulare Lake sediments on the northern boundary of the County (Wood and Dale 1964; Croft 1972).

The San Joaquin Valley is an asymmetrical syncline (Figure 4.9-3) or trough that runs north-south with the center along the western side of the valley. Although the San Joaquin Valley constitutes part of a discrete geomorphic province, the geology is internally variable in both stratigraphy and style of deformation. Stratigraphically, the greatest variation is the thick section of marine sediments in the southern part of the basin that grades to thinner, non-marine sediments north of Kern County. Structurally, the greatest differences are between the highly-folded sedimentary layers on the west and the little-deformed sedimentary cover on the east side of the valley (Bartow 1991).

Tectonic activity in the area has produced numerous geologic faults, many of which remain active today. Notable faults and folds are shown on Figure 4.9-3. Figure 4.9-3 also illustrates the position of the major oil fields in the Project Area relative to major structural features, such as the Bakersfield Arch and the Cenozoic Basin depositional axis. Two generalized west-to-east cross-sections are presented on Figure 4.9-4 and Figure 4.9-5 to further illustrate the variability in geology across the Project Area.

The Bakersfield Arch (Figure 4.9-3) separates the San Joaquin Valley in the Project Area into northern and southern areas. The arch does not have appreciable structural relief, but does have an influence on sedimentation. The thickest sequences of Tertiary sediments of these basins occur approximately coincident with the Pleistocene and Holocene Buena Vista and Kern Lake basins in the south and the Tulare Lake basin in the north. The Mesozoic and early Tertiary Great Valley sequence, on the other hand, thins southeastward and is apparently absent south of the Bakersfield Arch (Bartow 1991).

The highly folded western margin of the valley north of the Bakersfield Arch is characterized by Cenozoic folds and faults that trend, for the most part, slightly oblique to the San Andreas Fault in the southwest. The southeast boundary of the fold belt is arbitrarily placed east and south of Elk Hills where the fold trends change from northwest to west (Figures 4.9-4 and 4.9-5). The east boundary deviates from the valley syncline axis to include the subdued anticlines that, although lying east of the valley axis, are structurally more akin to the west-side fold belt than to the less-deformed eastern margin (Figure 4.9-5). The intensity of deformation increases southeastward along the fold belt as well as southwestward across the belt toward the San Andreas Fault. The increased intensity is evidenced by tighter folds and an increased number of reverse and thrust faults (Bartow 1991).

Normal faults along the east side of the valley are concentrated in the area of the Bakersfield Arch. These faults generally trend northwest to north, although a secondary west to west-northwest trend is apparent (Figures 4.9-4 and 4.9-5). The net displacement is down to the southwest, although down-to-the-northeast faults are present (Bartow and McDougall 1984; Bartow 1991).

South of the Bakersfield Arch, the structural trends are variable, but there is a general west trend along the southern margin of the basin (Figure 4.9-3). The northwest fold trends of the west side change to west-northwest where that region merges with the deformed belt at the south end of the valley. The northeast-trending White Wolf fault is the dominant structure (Figure 4.9-3). The White Wolf fault and the smaller Springs fault to the southeast both trend approximately parallel to the Garlock fault, which lies along the southeast side of the Tehachapi Mountains. Both faults, like the Garlock, show some geologic evidence of left-lateral movement. Farther northeast, the northwest-to-west-trending Edison fault is an older Tertiary normal fault (Bartow and McDougall 1984; Bartow 1991).

For the purposes of the 2015 FEIR and this SREIR, the Project Area is analyzed with reference to three Subareas: the Western, Central, and Eastern Subareas. The following paragraphs provide an overview of the hydrogeology in these areas:

- The Western Subarea is bounded by the Coast Range hills in western Kern County and by Interstate 5 on the east. As discussed below, due to the hydrogeology of this region, which includes marine sediments that readily dissolve into groundwater, water quality in the Western Subarea is relatively poor compared with the Central and Eastern Subareas). The

Corcoran Clay, or an equivalent clay barrier separating aquifers into deeper and shallower zones, is present in the eastern portion of this Subarea and separates shallow and deep groundwater zones. The geologic cross section presented on Figure 4.9-5 illustrates the occurrence of saline groundwater west of the Lost Hills (generally west of Interstate 5).

- The Central Subarea primarily includes the largely flat, gently sloping alluvial sediments located in the southern San Joaquin Valley floor portion of the Project Area east of Interstate 5 and west of Highway 65. Agriculture is the predominant land use, and groundwater production accounts for a substantial amount of the agricultural irrigation and municipal and industrial water use in this area. The Corcoran Clay is present throughout much of the Subarea and separates shallow and deep groundwater zones. The geologic cross section presented on Figure 4.9-5 illustrates that the groundwater in the upper several hundred to over one thousand feet is relatively fresh, making this the primary aquifer for the region.
- The Eastern Subarea is bounded by the West Sierra Foothills, up to an elevation of approximately 2,000 feet above mean sea level, portions of the gently sloping alluvial sediments downslope of the West Sierra Foothills, and the valley floor up to Highway 65. The geologic cross-section included as Figure 4.9-5 illustrates that the sediments thin towards the east as they overlay onto the granitic basin. In the West Sierra Foothills, the local geology is characterized by tight, poorly draining, low-solubility igneous and metamorphic rocks, which tend to have less impact on water composition of streams draining the area as compared to the geology of the Western Subarea. Groundwater wells in this area do not produce at rates comparable with the Central Subarea and are mostly used to meet domestic (i.e., private well) and small community demand. The alluvial areas are similar geologically to the Central Subarea, but are distinguished from the Western and Central Subareas, in part, by the absence of the Corcoran Clay. Groundwater production in the alluvial portion of the Subarea is more substantial than in the foothill areas.

The Project Area is located in the southern extreme of the San Joaquin Valley structural trough, which is filled with marine and continental sediments deposited during periodic inundation by the Pacific Ocean and by erosion of the surrounding mountains. Continental deposits shed from the surrounding mountains form an alluvial wedge that thickens from the valley margins toward the axis of the structural trough to about 30,000 feet. The thickest alluvium occurs in the south-central portion of Kern County, including locations in the Project Area (DWR 2006). Freshwater generally occurs in the uppermost 3,000 feet of the alluvium, and brackish water is typically found in deeper locations (Shelton et al. 2008).

The Kern County Subbasin and the White Wolf Subbasin (created in 2016 from the southern portion of the Kern County Subbasin) collectively have the largest surface area of any basin designated by the DWR in California. These basins are bounded to the north by the Kern County line and Tule Groundwater Subbasin, on the east and southeast by the Sierra Nevada Foothills and the Tehachapi Mountains, and on the southwest and west by the San Emigdio Mountains and Coast Ranges (Shelton et al. 2008). Aquifers commonly occur in loosely compacted soil saturated with groundwater. These aquifers are generally characterized as unconfined or confined aquifers.

Unconfined aquifers occur where the water table is exposed to the atmosphere through openings in overlying materials. Confined aquifers occur below a low permeability geologic unit that impedes vertical movement of groundwater. Groundwater in a confined aquifer is often under higher atmospheric pressure conditions. Geologic structures, such as bedrock or faults, can also constrain the lateral or vertical movement of groundwater. Groundwater generally flows westward out of the Sierra Nevada and Tehachapi Mountains toward the center of the San Joaquin Valley. North of the Kern River, groundwater flows west then north toward the Tulare Lakebed. South of the Kern River, groundwater flows toward the southwest (Burton et al. 2012).

The primary aquifers in the Kern County Subbasin and the White Wolf Subbasin consist of alluvium in the shallower aquifers, and marine and continental deposits in the deeper aquifers. The public supply wells in the primary aquifers are generally screened from 275 to 450 feet to 600 to 800 feet below the ground surface (Burton and Belitz 2012).

As discussed in this section and in the Supplemental Water Supply Baseline Technical Report (2020) (see Appendix D), groundwater supplies exist in specific basins and not in localized pockets of subbasins where a local water district controls all the water. Therefore, the use of the three geographical Subareas, which correspond to oilfield production areas that have different characteristics for depth of drilling and amount of wells, is appropriate for the analysis of the groundwater supply. The use of one local well will now be constrained by the SGMA authorities having jurisdiction over that well area for groundwater, and the local domestic water provider or water district for that well will not have autonomy to increase pumping or independently make determinations on pumping requirements. All of the basin included in this Project is under the jurisdiction of a GSA. As such, the analysis and discussion is basinwide, related to the three geographic Subareas that were used for analysis of all impacts, and provides a consistent and comprehensive discussion of baseline conditions that an individual localized analysis could not provide.

Water Bearing Formations

Sedimentary deposits in the San Joaquin Valley are divided from oldest to youngest into the Olcese and Santa Margarita Formations, the Tulare (western subbasin) and Kern River Formations (eastern subbasin), Older Alluvium/Stream and Terrace Deposits, and Younger Alluvium/Flood Basin Deposits (DWR 2006).

The Olcese and Santa Margarita Formations are current or potential sources of drinking water only in the northeastern portion of the subbasin where they occur as confined aquifers. They are Miocene-age deposits that vary from continental to marine in origin from east to west across the subbasin. The Olcese Formation is primarily sand and ranges in thickness from 100 to 450 feet. The Santa Margarita Formation consists of coarse sand and ranges in thickness from 200 to 600 feet (DWR 2006).

Both the Tulare and Kern River Formations are moderately to highly permeable and yield moderate to large quantities of water. These units are both Plio-Pleistocene age and represent west/east facies change across the subbasin. The Tulare Formation (western subbasin) contains up to 2,200 feet of interbedded, oxidized to reduced sands; gypsiferous clays; and gravels derived predominantly from Coast Range sources. The Kern River Formation includes 500 to 2,000 feet of poorly sorted, lenticular deposits of clay, silt, sand, and gravel derived from the Sierra Nevadas (DWR 2006).

The Older Alluvium/Stream and Terrace Deposits are moderately to highly permeable and yield large quantities of groundwater. The deposits are composed of up to 250 feet of Pleistocene-age lenticular clay, silt, sand, and gravel that are loosely consolidated to cemented and are exposed mainly at the subbasin margins. This sedimentary unit is often indistinguishable from the lower Tulare and Kern formations. Most of the freshwater aquifers in Kern County occur in the Older Alluvium/Stream and Terrace Deposits, and the Tulare and Kern Formations (DWR 2006).

The Younger Alluvium/Flood Basin Deposits are Holocene in age and vary in character and thickness around the subbasin. At the eastern and southern subbasin margins, this unit is composed of up to 150 feet of interstratified and discontinuous beds of clay, silt, sand, and gravel. In the southwestern subbasin, it is finer-grained and less permeable as it grades into fine-grained flood basin deposits underlying the historic beds of Buena Vista and Kern lakes in the southern subbasin. The flood basin deposits consist of silt, silty clay, sandy clay, and clay interbedded with poorly permeable sand layers. These flood basin deposits are difficult to distinguish from underlying fine-grained older alluvium and the total thickness of both units may be as much as 1,000 feet.

Recharge and Storage

Natural groundwater recharge in the Project Area is primarily from the Kern River, but is also generated by infiltration from intermittent streams along the edge of the basin (DWR 2006; Burton and Belitz 2012). Conjunctive use and groundwater banking programs are widely used in the Kern County Subbasin area. Groundwater banking is the storage and recharge of excess water supplies into aquifers during wet periods for later withdrawal/recovery for use during dry periods. Historically, during wet periods, after surface water imports have been used to meet irrigation and urban water needs, imported water has been recharged to groundwater aquifers. The groundwater is pumped and extracted through private and publicly owned facilities wells during dry periods when local or imported surface water supplies are insufficient to meet regional water demand. Public and privately operated groundwater banking facilities, and infiltration from agricultural and municipal irrigations, much of which uses surface water imported to the Kern County Subbasin, currently accounts for a much larger amount of recharge than from natural sources (Burton et al. 2012; Burton and Belitz 2012). Groundwater banking programs are located throughout most of the central portion of the Kern County Subbasin (Figure 4.9-6).

The Kern Water Bank Authority (KWBA) owns and operates the Kern Water Bank (KWB), located to the southeast of Bakersfield along the Kern River. The KWB is the largest water banking program in the world and has stored over 2 million AF of water since operations began in 1995. Other water banking facilities in or near the Project Area include:

- City of Bakersfield 2800 Acre Ground Water Recharge Project;
- Berrenda Mesa Banking;

- Pioneer Banking;
- Semitropic Water Storage District (SWSD) Banking;
- Arvin-Edison Water Storage District (AEWSD) Banking;
- Kern Tulare and Rag Gulch Water Districts Banking;
- Buena Vista Water Storage District (BVGSA) Banking;
- Rosedale-Rio Bravo Water Storage District Banking;
- Kern Delta Water District Banking; and
- Cawelo Water District (CWD) Banking.

The maximum annual recharge capacity in the Kern County Subbasin area has been estimated at 1.5 million AF per year (AFY), with a maximum recovery of 900,000 AFY (KCWA 2011a). The KCWA estimates that 40,000,000 AF of groundwater is stored, and that an additional 10,000,000 AF of groundwater storage capacity is located within and in the vicinity of the Project Area (DWR 2006). The region's total storage capacity is 50,000,000 AF, and 10,000,000 AF is available for conjunctive use and groundwater banking operations. As of 2011, approximately 5,400,000 AF was in managed groundwater storage in the Kern County Subbasin. As discussed below, a coordinated water budget for the Kern County Subbasin, which no longer includes the White Wolf Subbasin, was adopted in accordance with the SGMA. The water budget analysis indicates that the average annual groundwater recharge in the currently defined Kern County Subbasin is 1,400,362 AFY with an estimated subsurface outflow of 87,102 AFY (KGA 2020, Appendix H).

Between 1926 and 1970, groundwater extraction resulted in more than 8 feet of subsidence in the north-central portion of the subbasin and 9 feet in the south-central area. The basin experienced a 15-foot decrease in water level from 1970 through 1978, a 15-foot increase from 1978 through 1988, and an 8-foot decrease from 1988 through 1997. The average subbasin water level, however, remained essentially unchanged from 1970 to 2000, subject to significant local variability ranging from increases of over 30 feet at the southeast valley margin and in the Lost Hills/Buttonwillow areas to decreases of over 25 and 50 feet in the Bakersfield area and McFarland/Shafter areas, respectively (DWR 2006). Data collected by the KCWA indicate that average groundwater levels decreased by 2.5 feet in 2013 (KCWA 2013).

In 2009, the California Water Code (CWC) was amended to require that the DWR develop and implement a new California statewide groundwater elevation monitoring (CASGEM) program. The CASGEM program collects data on groundwater levels and use for 515 designated basins in the state, including the Kern County Subbasin that underlies most of the Project Area. The program also ranks the severity of each basin's groundwater impacts on the basis of several factors, including subbasin population growth, reliance on groundwater, and level of extraction. The SGMA, which was adopted in 2014, requires that regional Groundwater Sustainability Agencies (GSAs) adopt groundwater sustainability plans (GSPs) to achieve SGMA groundwater sustainability management objectives (discussed in Section 4.9.3, Regulatory Setting) for state subbasins in accordance with a compliance schedule based on the severity or priority designation of each subbasin's groundwater conditions. The priority designations include low and lower priority basins and subbasins, which are not required to be regulated under the SGMA, medium priority basins or subbasins, which are required to be regulated by one or more GSAs and adopted GSPs by January 31, 2022, and higher priority and/or critically overdrafted basins and subbasins, which are required to be regulated by one or more GSAs and adopted GSPs by January 31, 2020.

Sustainable Groundwater Management Act

SGMA Overview

As discussed in Section 3.1, Project Overview, of this SREIR, the Appellate Court directed that the water supply baseline for the Project be updated to include and consider new information available from the implementation of the SGMA in the Project Area since the 2015 FEIR was certified. The SGMA "is a complex program with a new language that must be mastered by consultants, basin managers, and stakeholders alike," as well as a "bold and untested groundwater management program." This subsection provides an overview of the SGMA process generally. The following subsection describes how the available SGMA information since the 2015 FEIR was certified was used to update the Project's water supply baseline and in the evaluation of potential Project groundwater and water supply impacts.

The SGMA was adopted by California in 2014 and provides, for the first time in state history, "a framework for sustainable, groundwater management" resulting "in the management and use of groundwater in a manner that can be maintained during the planning and implementation horizon without causing undesirable result" (DWR 2020). The legislation and the governor's signing statement emphasize that "groundwater management in California is best accomplished locally." To achieve these objectives, "SGMA empowers local agencies to form Groundwater Sustainability Agencies (GSAs) to manage basins sustainably and requires those GSAs to adopt Groundwater Sustainability Plans (GSPs) for crucial groundwater basins in California" (DWR 2020). To support local management by the GSAs, the SGMA identifies roles for various state agencies to support sustainable groundwater management, including the DWR, which develops regulations for groundwater sustainability plans and then reviews those plans once submitted, and the State Water Resources Control Board (SWRCB), which has oversight and enforcement authority. State agencies also provide resources to help support the GSAs in the implementation of local control of groundwater resources (Maven's Notebook 2020).

The SGMA requires that the GSPs adopted by GSAs for applicable basins achieve sustainable groundwater management within 20 years of plan adoption by avoiding six "undesirable results" as defined in the Act: lowering groundwater levels, reduction of groundwater storage, seawater intrusion, degraded groundwater quality, land subsidence, and depletions of interconnected surface water. The GSAs have the management authority to plan for and implement measures intended to achieve the SGMA objectives within the statutory deadlines. In general, the SGMA requires that each GSA cover an exclusive groundwater basin or subbasin, or portion of a basin or subbasin, with no overlapping jurisdictional boundaries. Section 10723 (c) (1) of the California Water Code identifies several existing local agencies as "the exclusive local agencies within their respective statutory boundaries with powers to comply" with the SGMA. None of these "deemed _exclusive" agencies are located in the Project Area. The SGMA provides for three alternatives for implementation where "deemed exclusive" GSAs do not exist, including formation of: (1) a single GSA that covers an entire basin and prepares a single GSP; (2) multiple GSAs in a basin that prepare a single GSP for the whole basin; or (3) multiple GSAs that prepare multiple GSPs for a basin, which must be implemented under a basin-wide coordination agreement. (Maven's Notebook 2020). As discussed in more detail and as shown in Figure 4.9-AA, below, the Kern County Subbasin underlies the substantial majority of the Project Area, and 11 GSAs, five GSPs, and 15 management area plans, all subject to a coordination agreement, have been adopted for the subbasin. GSAs and GSPs have also been formed and adopted for small portions of other subbasins and basins subject to the SGMA in the Project Area that are primarily located outside the County. In 2016, a portion of the Kern County Subbasin located to the south of the White Wolf Fault was redesignated as a separate subbasin and a GSA has been formed for this area, with a GSP required by the end of January 2022. As required by Water Code Section 10723.8, all of the GSAs in the Project Area were formed to avoid jurisdictional boundary overlaps._

Water Code Section 10723.8 states that once a GSA has been formed in accordance with the SGMA, it "shall be presumed to be the exclusive groundwater sustainability agency within the area of the basin" identified by the GSA. Water Code Section 10725 provides that a duly-formed GSA "may exercise any of the powers" created by the SGMA legislation, provided that the GSA "adopts and submits to the [DWR] a groundwater sustainability plan or prescribed alternative documentation" in accordance with the Act. Water Code Sections 10275.2 to 10726.4 describe the powers that a GSA may exercise under SGMA and an adopted GSP, including investigations, monitoring, and water use documentation, surface water acquisitions and enhanced groundwater recharge, the authorization of temporary and permanent groundwater transfers, and land acquisition for management, fallowing or other purposes. Water Code Section 10726.4(a) further provides GSAs with the unique "additional authority" to "regulate groundwater extraction using that authority," including "regulating, limiting, or suspending extractions from individual groundwater wells or extractions from groundwater wells in the aggregate, construction of new groundwater wells, enlargement of existing groundwater wells, or reactivation of abandoned groundwater wells, or otherwise establishing groundwater extraction allocations." The authority of GSAs to directly control groundwater extractions from individual or basin-wide aggregations of wells represents one of the most significant regulatory innovations created by the SGMA.

The SGMA requires that each GSA must "consider the interests of all beneficial uses and users of groundwater, as well as those responsible for implementing GSPs." Water Code Section 10723.2 states that these interests include, but are not limited to all of the following: (a) holders of overlying ground water rights, including: (1) agricultural users, including farmers, ranchers, and dairy professionals, and (2) domestic well owners; (b) municipal well operators; (c) public water systems; (d) local land use planning agencies; (e) environmental users of groundwater; (f) surface water users, if there is a hydrologic connection between surface and groundwater bodies; (g) the federal government, including, but not limited to, the military and managers of federal lands; (h) California Native American Tribes; (i) disadvantaged communities, including, but not limited to, those served by private domestic wells or small community water systems; and (j) entities listed in Water Code Section 10927 that are monitoring and reporting groundwater elevations in all or a part of a groundwater basin managed by the GSA. The coordination of outreach, input from, *and integration of these multiple interests represents a new, historically unprecedented, and complex process for formulating groundwater management plans that must comprehensively achieve SGMA requirements for entire basins and subbasins by each GSA in the Project Area and in the state.*

Consistent with the SGMA, GSAs in the Project Area have adopted GSPs and management area plans that are intended to exclusively implement the SGMA within their jurisdictional boundaries. The GSP adopted by the Kern River GSA states that the "KRGSA is an exclusive Groundwater Sustainability Agency (GSA) composed of member agencies including the City of Bakersfield, Kern Delta Water District (KDWD), Kern County Water Agency (KCWA) Improvement District No. 4 (ID4), North of the River Municipal Water District/Oildale Mutual Water Company (NORMWD/OMWC), and East Niles Community Services District (ENCSD)….As an exclusive GSA, the KRGSA exclusively manages groundwater within the KRGSA boundaries" (KRGSA 2020). The Kern Groundwater Authority (KGA) GSA, which covers the largest portions of the subbasin within the Project Area, states that the "authority granted to the KGA is to develop, adopt, and implement a GSP that would be available to those lands within the boundaries of the KGA members" and "provide each member the sole right and responsibility to implement SGMA within its respective boundaries and/or management areas, in a manner determined by the member." The KGA was formed by a joint powers agreements that "stipulates that each member agency has the sole right and responsibility to develop and implement SGMA within its respective boundaries" (KGA 2020). The Olcese GSP states that "Pursuant to Section 10723 et. Seq. of the California Water Code, the Olcese Water District formed the Olcese GSA and was granted exclusive GSA status for the Plan Area described herein by DWR under SGMA. The Olcese GSA is an exclusive agency and is preparing its own GSP" (EKI Environment & Water 2020). The Buena Vista GSP states that "The BVGSA is an exclusive GSA engaged in coordination and outreach efforts across the Kern County Subbasin, as well as within the GSA's boundaries" (BVWSD GSA 2020).

As discussed in further detail below, the Kern County Subbasin is covered by 11 GSAs, five GSPs, and 15 management area plans in the KGA GSP. To comply with the SGMA, the implementation of the GSPs and management area plans is subject to the terms and conditions of a basin-wide Coordination Agreement. (KRGSA 2020, Appendix D). Water Code Section 10727.6 requires that the Coordination Agreement ensure that SGMA implementation within a basin or subbasin utilize the same groundwater elevation data, groundwater extraction data, information about surface water supply, total water use, change in groundwater storage, and analyses of the basin's water budget and sustainable yield. The SGMA and the SGMA regulations adopted by the DWR, which are discussed in more detail below, require that all of the technical information used to implement a GSP or management area plan must be prepared by or under the direction of a professional geologist or professional engineer. Consequently, each GSA, and each adopted GSP and management area plan, must not only take account of the interests of all beneficial uses and users of groundwater, but it must also coordinate with all other GSAs and GSPs in the subbasin, develop and utilize common technical hydrologic and other information prepared by professional engineers and geologists, and ensure that SGMA objectives are comprehensively achieved for the applicable basin or subbasin as a whole. The complexity of this process is one reason why the state legislature provided GSAs with a 20-year period for achieving SGMA objectives. As *summarized by an SGMA technical consultant in a widely circulated discussion of the state's first ever GSP development process, "There is no such thing as a perfect GSP….the five-year update is an opportunity to fine-tune the GSP elements such as sustainable management criteria, monitoring networks, and the groundwater model…. [GSAs] have 20 years to work out the details to achieve sustainability" (Montgomery & Associates 2020).*

As discussed in more detail below and in Section 4.17, Utilities and Service Systems in this SREIR, the adopted GSPs in the Project Area identify several planning and management actions (SGMA Projects) that could be implemented to achieve SGMA objectives over time. The plans are specifically intended to be adaptively managed in response to continual basin monitoring and analysis, including the development of new measures if necessary and management that would address potentially significant social and economic harm in addition to meeting SGMA objectives. The adaptive management sections of the Kern River GSP states that "six projects will begin implementation during the first five years of the GSP. However, several projects will require adjustment and possible re-direction over time to optimize project performance and avoid undesirable results. Incorporating this concept of adaptive management will be key to achieving the KRGSA sustainability goal" (KRGSA 2020, 7-3). Section 7.4.4 of the plan includes additional considerations for adaptive management as follows:

> *It is recognized that demand reduction projects could have a detrimental impact on the local economy, livelihood of residents and business owners, and the well-being of Metropolitan Bakersfield and Kern County. Therefore, large-scale reductions are not proposed in Phase One and may be unnecessary for achieving the sustainability goal. At a minimum, such actions are delayed until later in the implementation period to allow water supply projects the opportunity to sustainably support current and projected growth in the beneficial uses of groundwater. (KRGSA 2020, 7-26)*

Similarly, the KGA GSP focuses on adaptive management that would allow for continued agricultural activity in Kern County, notwithstanding the loss of anticipated surface water supplies due to regulatory constraints which, if implemented as planned, would have avoided overdraft conditions:

> *In Kern County a wide variety of crops are produced on approximately 900,000 acres, making it a major contributor to California's agricultural economy. One important honor that Kern County is known for is its agricultural industry ranking. Kern County currently is ranked the #1 agricultural producing county in the United States and has been for the last three years with gross value of all agricultural commodities produced in 2017 estimated at $7.25 billion (Kern County Department of Agriculture and Measurement Standards, 2018). The top five commodities are grapes, almonds, citrus, milk, and pistachios, which make up more than $4.5 billion (63%) of the total value. With this, Kern County agriculture is the largest employer in the region with 1 in every 5 jobs related to agriculture. The communities, the economy, and local governments are and have been reliant on Kern County agriculture and are dedicated to preserving the viability of agriculture into the future.* Bulletin 118 published by California Department of Water Resources (DWR) in January 1980 states that "The Kern County Water Agency, which

> *covers the Kern County Basin, presently receives about half of its maximum annual entitlement from the State Water Project. If no new lands were to go into production, and the full entitlement from the State Water Project were delivered today, there would be no overdraft in Kern County as a whole." Harvested acres in Kern County have remained relatively steady at an average of 858,000 acres a year with only a 10% annual fluctuation from that average between 1980 and 2017. Since the operation of the State Water Project (SWP) in 1968 until 2007, SWP contractors received on average 86% of their entitlement. However, in May 2007, Federal Judge Oliver Wagner overturned a federal scientific study that aimed to protect Delta Smelt in the Sacramento-San Joaquin Delta (Delta) resulting in curtailing Delta export pumping operations to protect the continued existence of the fish. In addition, the State of California experienced a historic extended drought from 2012 to 2016. As a result, SWP contractors received on an average only 48% of their entitlement from 2008 to 2016. Despite the reduction in SWP deliveries, the groundwater overdraft in the entire Subbasin declined from 600,000 acre-feet per year in 1980 (Bulletin 118-80) to a current estimate of 324,300 acre-feet in 2015…. Collectively, the projects and management actions currently proposed provide a reasonable approach for sustainable management of the groundwater Subbasin and can be adaptively managed to meet future challenges as necessary. (KGA 2020, 1-2)*

The adaptive management approach in the Project Area's GSPs is consistent with a recent assessment of GSPs by a team of researchers from the Public Policy Institute of California, U. C. Davis, and U. C. Merced. The analysis found that GSP reliability was subject to uncertainty, and that a relatively simple statistical model suggests that reducing historical overdrafts, one of the major SGMA objectives, would be more likely to be achieved by greater groundwater pumping restrictions in contrast with other potential management actions. However, the study also found that this implementation approach also rapidly increases agricultural economic losses. The researchers recommend that "[a]daptive methods to account for California's hydrologic variability and the inherent uncertainties are essential for a dynamic response to changing conditions. SGMA's requirement that GSPs update their plans at least every five years provides an important opportunity to incorporate new information and lessons, and adapt to changing conditions." (Escriva-Boua 2020)

In summary, the SGMA is a locally based approach to long-term groundwater sustainable management that allows for a variety of approaches and requires that undesirable results be avoided by implementing comprehensive solutions for each applicable basin and subbasin. The formation of GSAs; the adoption of GSPs and management area plans; the development of technical hydrological information at a basin, subbasin, and plan level; and the consideration and integration of a wide range of interests affected by groundwater has never before been attempted, let alone successfully implemented, in California. The adopted GSPs in the Project Area represent initial approaches for implementing the SGMA that will be adaptively managed and revised as necessary to comprehensively meet SGMA requirements over the statutory 20-year compliance period and a 50-year planning and implementation horizon.

Water Supply Baseline Update

This SREIR updates the water supply baseline and Project water supply impact analysis with SGMA information available since the 2015 FEIR. Groundwater (Section 4.9, Hydrology and Water Quality) and water supply (Section 4.17, Utilities and Service Systems) conditions are described for the Project Area as a whole and for three subareas: the western, central, and eastern portion of the Project Area. This analytical framework reflects both the hydrogeology of the Project Area and the comprehensive, basin-wide sustainable groundwater planning solutions required to comply with the SGMA. Tthe Eastern Subarea encompasses the Sierra Nevada foothills, which have generally higher groundwater quality and receive more recharge from adjacent watershed runoff than other locations. The hydrogeology of the Central Subarea is dominated by the Central Valley plain and agricultural land uses where a small percentage of potential Project oil and gas activity would occur. The Western Subarea includes the coastal range that forms the western edge of the Central Valley with significantly lower groundwater quality and less surface runoff. As shown in Figure 4.9-AA, below, the Kern County Subbasin underlies almost all of the Project Area and is being managed under a coordination agreement by 11 GSAs implementing five GSPs and 15 management area plans to comprehensively achieve SGMA requirements by 2040 for the basin as a whole. The Project Area and subarea analyses therefore represent a logical and appropriate approach for analyzing the Project's potential hydrology and water quality and water supply impacts that is consistent with the SGMA's coordinated and comprehensive basin-wide management requirements.

To update the water supply baseline, each GSP and management area plan adopted for any portion of the Project Area was reviewed to identify the extent to which oil and gas operations were identified as a significant factor affecting the achievement of SGMA objectives for applicable subbasins and basins. As discussed above, the SGMA requires that each designated basin and subbasin be managed under a common set of assumptions and objectives, and each GSP and management area plan provide information about potential oil and gas water supply impacts within discrete locations throughout the Project Area where local water management agencies have developed specialized expertise and information concerning local conditions based on common, basin-wide technical, planning and management criteria. Most GSPs and management area plans include water supply and demand projections over a 50-year planning and implementation horizon, which extends to 2070 for the Kern County Subbasin, for the applicable plan area based on the coordinated water budget required under the Coordination Agreement. The purpose of this analysis was determine whether any GSP or management area plan in the Project Area provided new information suggesting that that oil and gas activities would adversely affect anticipated water supplies, water demand, water quality, subsidence, and other SGMA requirements in any portion of the Project Area or one or more subareas as reflected in each plan to a greater extent than considered in the 2015 FEIR.

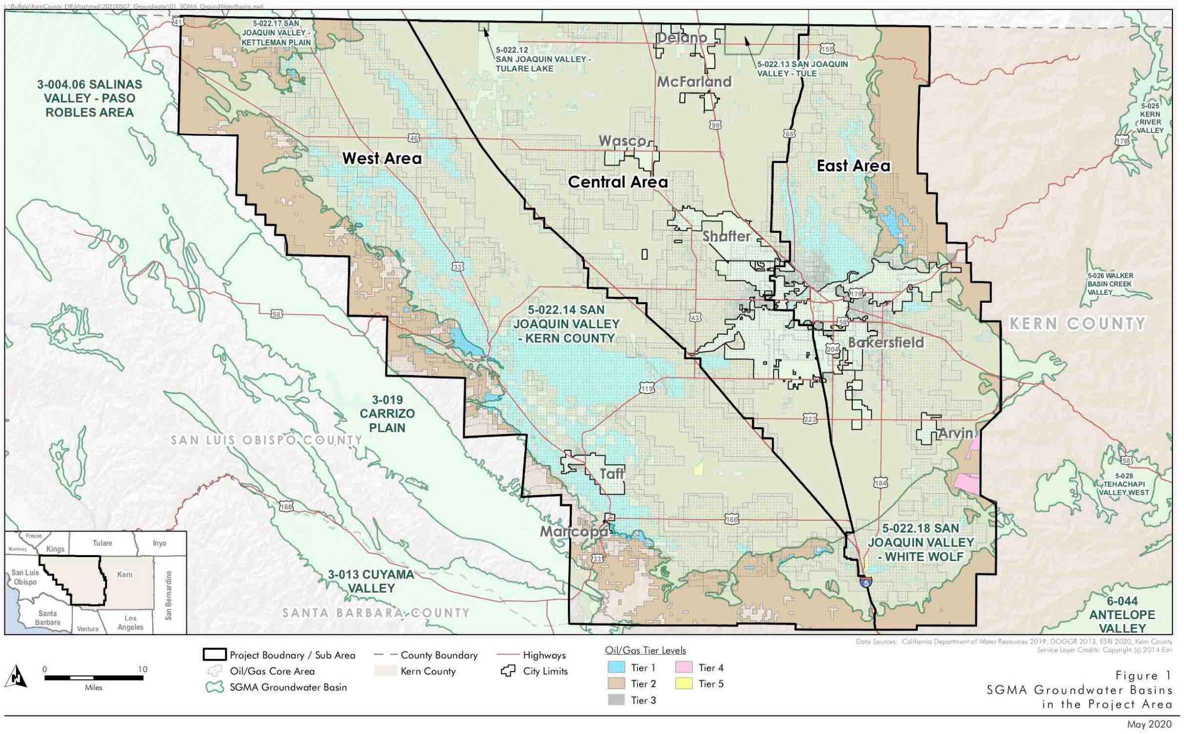
As summarized below, and in Appendix D and Section 4.17, Utilities and Service Systems, none of the adopted GSPs and management areas plans within the Project Area identify oil and gas operations as a significant factor affecting the achievement of any of the SGMA objectives. None of the 50-year water supply and demand projections included in any adopted GSP or management area plan include oil and gas–related activity as a significant net consumer or other factor *reducing available supplies over time. Almost all of the GSPs and management area plans explicitly exclude oil and gas operational areas, and exempted aquifers under the Underground Injection Control program (discussed below), from SGMA-regulated groundwater basins. Several identify the potential use of treated and/or blended oil and gas produced water as a potential source of new imported water that would increase available supplies for agricultural irrigation purposes and reduce potential groundwater demand over time. Consequently, the review of each of the GSPs and management area plans in the Project Area determined that none of the plans provided new information indicating that the Project's water supply and other SGMA-related impacts, including water quality, would be greater in magnitude or scope than previously considered. In contrast, the GSPs and management area plans do provide new information indicating that the importation of treated produced water from oil and gas operations into several SGMA plan areas could increase available water supplies and facilitate SGMA implementation.*

The following sections discuss the designation and SGMA prioritization of groundwater basins and subbasins, GSA formation, and GSP and management area plan adoption in the Project Area. The discussion of oil and gas activities in each adopted GSP and management area plan is summarized below under Project Area Groundwater Sustainability Plans and Oil and Gas Activities, and in more detail in Appendix D of this SREIR.

SGMA Basin and Subbasin Priority in the Project Area

As shown in Figure 4.9-AA, DWR-designated groundwater subbasin 5-022.14, which is the currently defined Kern County Subbasin (KCS), underlies a significant majority of the Project Area and each Subarea. The KCS extends north from the White Wolf fault in the southern portion of the Project Area to the foothills bordering the Project Area to the east and west, and to the northern boundary of the County. In 2016, the DWR approved a basin boundary modification for the KCS that resulted in the creation of new subbasin 5-022.18, the "White Wolf subbasin," in the southern portion of the Project Area south of the White Wolf fault. The White Wolf subbasin was a part of the KCS prior to the approved boundary modification in 2016. A small portion of subbasin 5-022.13, the Tule subbasin, extends into the Central Subarea of the Project Area from Tulare County to the north. A portion of subbasin 5-022.17, the Kettleman Plain subbasin extends into the Western Subarea, and a small part of subbasin 5-022.12, the Tulare Lake subbasin extends into the Central Subarea, from Kings County to the north. Small portions of Basin 3-019, the Carrizo Plain basin, and Basin 3-013, the Cuyama Valley basin, extend into the far southwest corner of the Western Subarea from San Luis Obispo County to the west.

Figure 4.9-AA: DWR-Designated Groundwater Basins and Subbasins in the Project Area June 2020

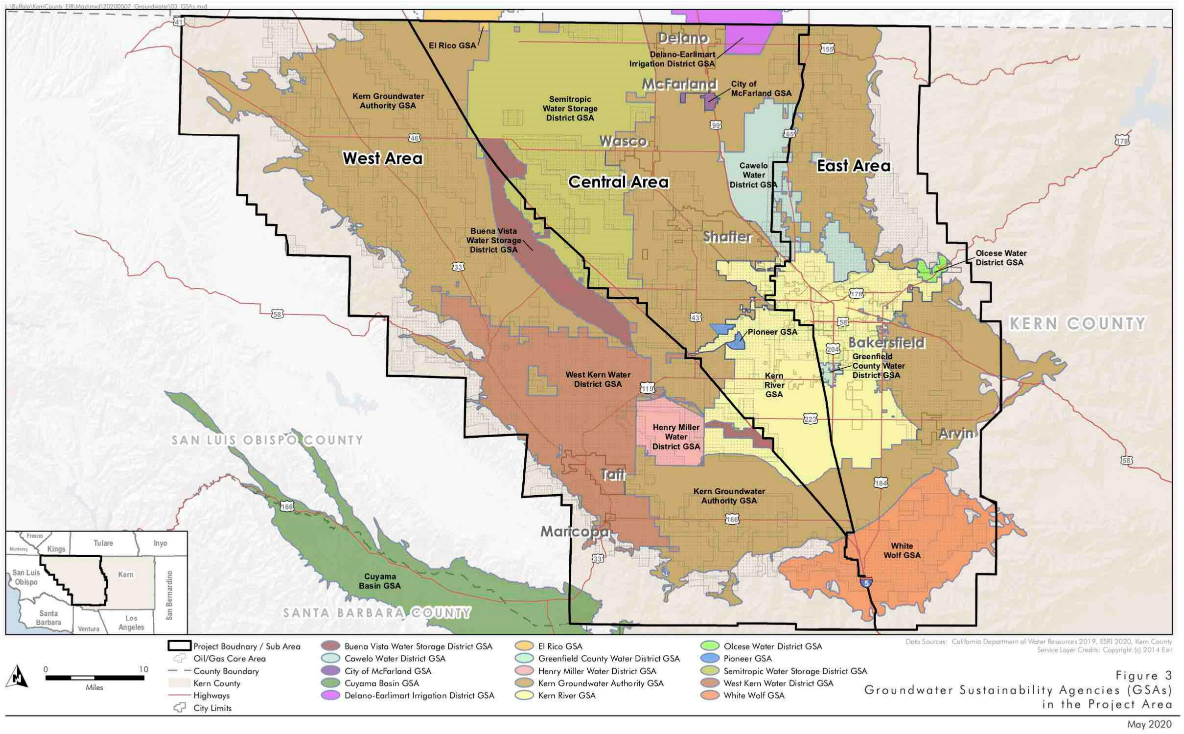


The DWR has designated the KCS, the Tule subbasin, the Tulare Lake subbasin and the northern part of the Cuyama Valley basin, including the small portion extending into the southwest corner of the Project Area, as high-priority and critically overdrafted. The SGMA requires that GSPs be adopted for these basins by January 31, 2020. The White Wolf subbasin was designated as medium priority when the basin boundary adjustment affecting the KCS was approved in 2016. A GSP is required for the White Wolf subbasin by January 31, 2022. The Carrizo Plain basin and the Kettleman Plain subbasin are low or very low priority basins and do not require GSPs under the SGMA (https://sgma.water.ca.gov/portal/).

GSA Formation in the Project Area

The SGMA requires that GSAs with exclusive jurisdiction over a basin (or a portion of a basin over which they will have jurisdiction) be created for high and medium priority basins by June 30, 2017. As shown in Figure 4.9-BB, GSAs have been formed for all of the high and medium priority basins and subbasins in the Project Area, including the KCS, the Tule subbasin, the Tulare Lake subbasin, the Cuyama Valley basin, and the White Wolf subbasin. No GSAs are required or have been formed for the Carrizo Plain basin or the Kettleman Plain subbasin.

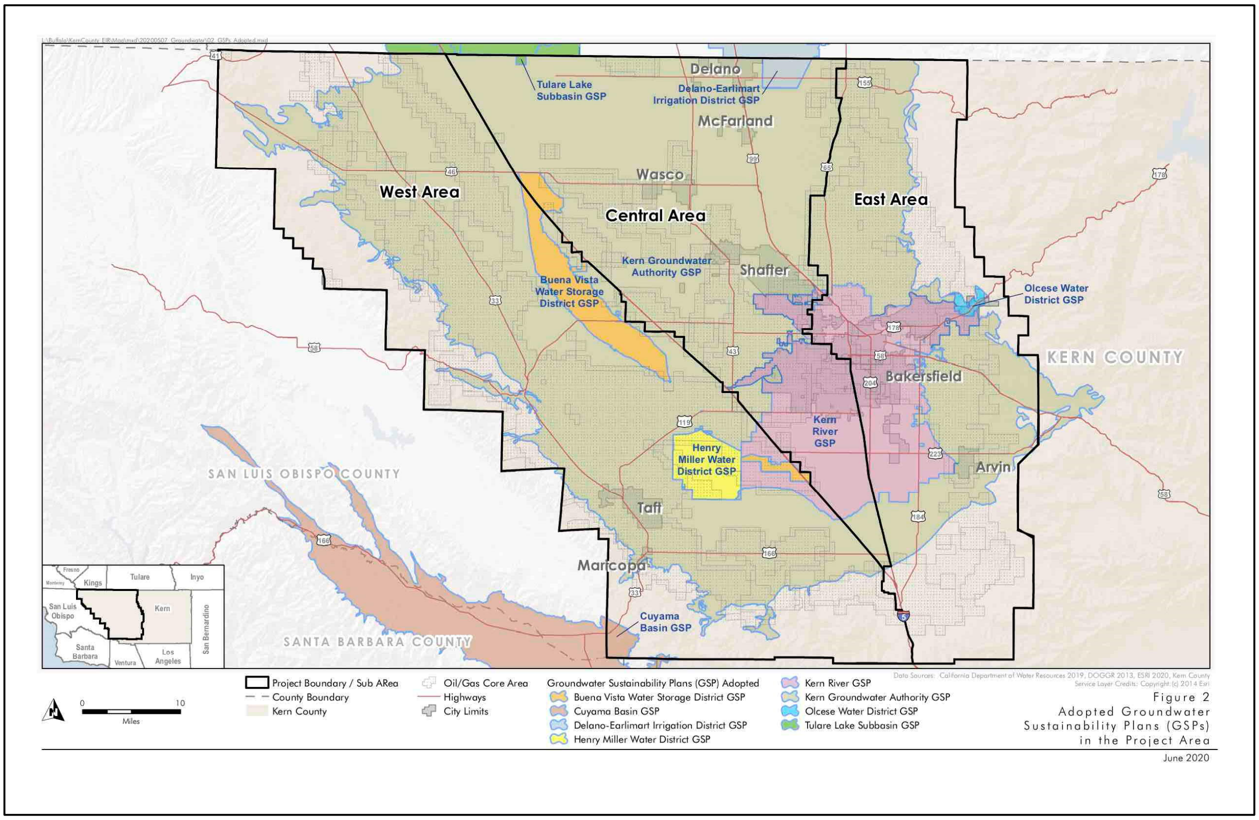
Figure 4.9-BB: GSAs Formed in the Project Area



GSP Adoption in the Project Area

As shown in Figure 4.9-CC, GSPs have been adopted for all of the high priority and critically overdrafted basins and subbasins in the Project Area, including the KCS, the Tule subbasin, the Tulare Lake subbasin, and the northern portion of the Cuyama Valley basin. The White Wolf subbasin must be covered by a GSP by January 31, 2022, and none has as yet been adopted. No other GSPs are required in the Project Area under the SGMA.

Figure 4.9-CC: GSPs Adopted in the Project Area



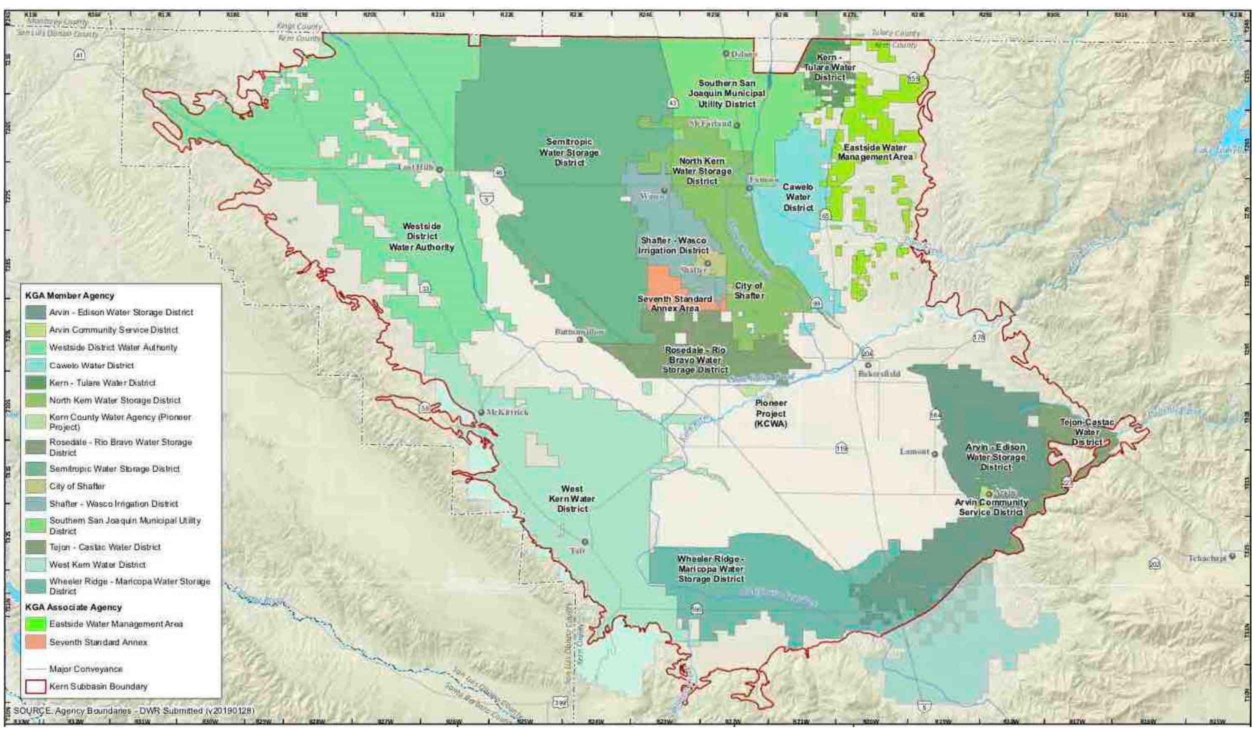
Section 354.20 of the SGMA regulations allows for the implementation of management area plans within the GSPs to implement the SGMA in response to local conditions. Fifteen management area plans have been prepared in conjunction with the ~~*Kern Groundwater Authority (*~~KGA~~*)*~~ GSP. The management areas were created by water districts and member agencies under the KGA to support groundwater sustainability in the KCS. The majority of the management areas in the region reflect established local water district boundaries. Water districts and member agencies under the KGA maintain and manage water rights, contracts, and governing agreements in their regions. The KGA GSP states that by creating their own management areas, water districts and KGA members can maintain and manage maximum flexibility and control over SGMA compliance and implement projects and management actions applicable to their respective service areas (KGA 2020). The management area plans in the KGA GSP include the following:

- AEWSD Management Area plan
- Cawelo GSA Management Area plan
- Eastside Water Management Area (EWMA) plan
- Kern County Water Agency - Pioneer Project plan
- Kern Water Bank Authority plan
- Kern-Tulare Water District (KTWD) Management Area plan

- North Kern Water Storage District (NKWSD) - Shafter-Wasco Irrigation District (SWID) Management Area plan
- Rosedale-Rio Bravo Management Area plan
- SWSD GSA Management Area plan
- SWID 7th Standard Annex Area Management Area plan
- Southern San Joaquin Municipal Utility District Management Area G Plan
- Tejon-Castac Water District (TCWD) Management Area plan
- West Kern Water District (WKWD) Management Area plan
- Westside District Water Authority (WDWA) Management Area plan
- Wheeler Ridge-Maricopa Water Storage District (WRMWSD) Management Area plan

Figure 4.9-DD shows the locations of the KGA member agencies included in the 15 management area plans. The KGA GSP and the KGA management area plans include most of the Project Area in the KCS subject to County jurisdiction.

Figure 4.9-DD: Locations of KGA GSP Member Agencies (KGA 2020)



The Kern River GSP (KRGSP) includes an approximately 93,473-acre Urban Management Area; an approximately 132,282-acre Agricultural Management Area; and an approximately 5,045-acre groundwater Banking Management Area (KRGSA 2020). The Buena Vista GSP includes the Maples Management Area and the Buttonwillow Management Area (BVWSD GSA 2020). The Olcese GSP is being managed as a single Management Area (EKI Environment & Water 2020).

The Henry Miller GSP is also a managed as a single management area focused on the Buena Vista Lakebed in the Project Area (Luhdorff & Scalmanini 2020).

There are approximately 440,950 acres of lands in the KCS that are not within an established water district ("non-districted" land). In certain parts of California, non-districted lands are covered for SGMA purposes by County governments that form a GSA or directly participate in a GSA. Kern County was initially a member of the KGA but withdrew in December 2018. The KGA, KGA member agencies, and the KCWA subsequently extended SGMA coverage by means of landowner agreements to approximately 242,180 acres of non-districted lands in the KCS. The KGA GSP indicates that there are approximately 198,770 acres of remaining non-districted lands in the subbasin not currently covered, most of which are grazing lands or lands associated with oil production where minimal or no groundwater usage exists. Non-districted landowners that do not desire SGMA coverage under the KGA GSP will eventually be removed from the KGA GSA boundary and will report directly to the State Water Resources Control Board for SGMA purposes. The KGA GSP states that management plans and groundwater models developed for the KCS have been coordinated to cover non-districted lands in the historic, baseline, and future projections for the subbasin. The GSAs in the KCS have also agreed to monitor non-districted lands and to include the monitoring data in the annual reports required by SGMA (KGA 2020).

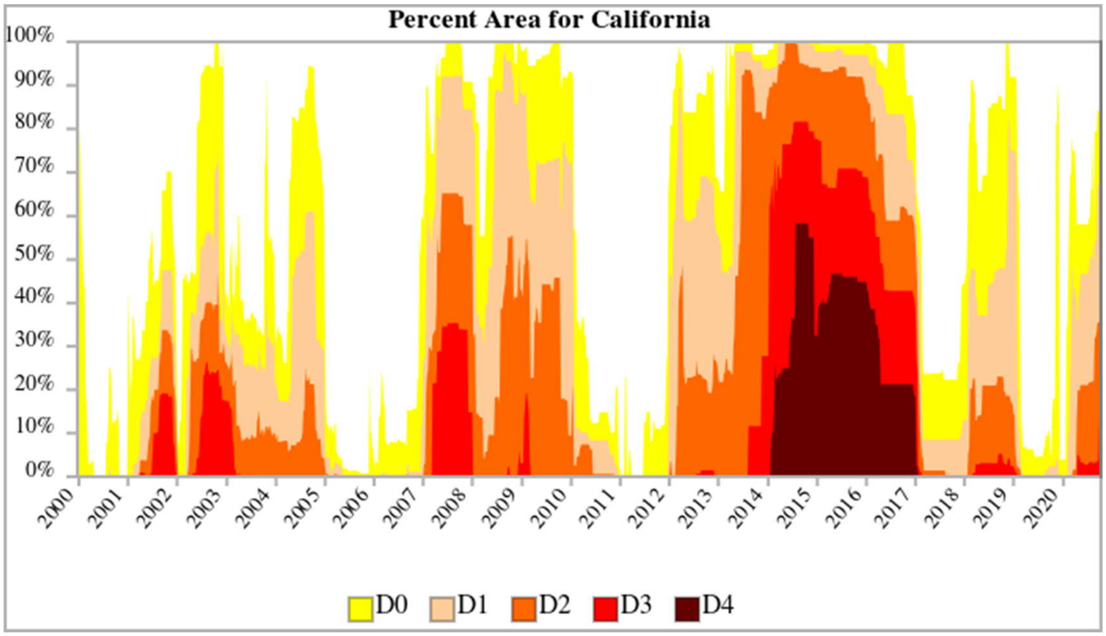
The GSPs were adopted and submitted to the DWR by January 31, 2020 in accordance with the SGMA. The DWR maintains a website, the SGMA Portal,) that provides current information about GSAs, GSPs, and other SGMA information. The SGMA Portal (https://sgma.water.ca.gov/portal/) shows that the comment period for the five KCS GSPs ended on June 3, 2020, after an extension for the coronavirus emergency in the state. None of the GSPs for the KCS have been approved by the DWR in accordance with SGMA regulations.

In January 2020, the GSAs within the KCS executed a Coordination Agreement (KRGSA 2020, Appendix D). The purpose of the Agreement is to "comply with SGMA coordination requirements and ensure that the multiple GSPs within the [KCS] are developed and implemented utilizing the same methodologies and assumptions as required under the SGMA and Title 23 of the California Code of Regulations, and that the elements of the GSPs are appropriately coordinated to support sustainable management." The Agreement establishes a Basin Coordinating Committee, a plan manager, a coordinated groundwater monitoring network, and data and information exchange procedures. Consistent with SGMA Section 10727.6 and Section 357.4 of the SGMA regulations, the Agreement requires that each GSP for the KCS use the "same data and methodologies" for "(1) groundwater elevation data; (2) groundwater extraction data; (3) surface water supply; (4) total water use; (5) change in groundwater storage; (6) water budget; and (7) sustainable yield." As required by Section 354.18 of the SGMA regulations, the Agreement requires that the GSAs "prepare a coordinated water budget: for the KCS to provide "an accounting and assessment of the total annual volume of groundwater and surface water entering and leaving the [KCS] including historical, current and projected water budget conditions and change in the volume of water stored." A coordinated water budget was completed for the KCS in January 2020 and attached to the Coordination Agreement. As required by Section 356.2, on April 1 2020 the KCS GSAs submitted an annual report to the DWR, including groundwater elevation data; groundwater extraction; surface water supply used or available for use for groundwater recharge or in lieu use;

total water use; water source type, and; changes in groundwater in storage for the prior water year. For more information concerning the coordinated water budget and the annual report, see Section 4.17.2, Utilities and Service Systems, Environmental Setting.

The state of California obtains about one-third of its water supply from the snowmelt in the Sierra Nevada Mountains. Snow melt is the primary source for water that is delivered to the Project Area through state and federal canal projects. California recently experienced a severe drought, and on January 17, 2014, the Governor Brown proclaimed a drought state of emergency and directed state officials to take all necessary actions to prepare for these drought conditions (State of California 2014). The drought period and the state's subsequent recovery have been tracked on a weekly basis by the National Integrated Drought Information System, which publishes the U.S. Drought Monitor (USDM). The USDM is updated each Thursday to show the location and intensity of drought across the country, including in California. The USDM identifies areas that are Abnormally Dry (D0), which is defined as "a precursor to drought, not actually drought"; as well as Moderate (D1); Severe (D2); Extreme (D3); and Exceptional (D4) drought conditions. The USDM has been maintained since 2000. Figure 4.9-EE is the USDM summary of the percentage of the total land area of California in D0 drought precursor, D1-D4 drought conditions, and no drought, *as of October 2020*. Over the last two decades, the USDM shows that California has experienced multiple periods in which portions of the state were determined to be in D0 drought precursor and D1-D4 drought conditions. The state experienced a prolonged period of exceptional drought, which peaked in July 2014 when more than 58 % of California was in D4 condition. As discussed in the 2018 Supplemental Environmental Impact Report (SREIR Volume 8), California is inherently subject to varying periods of wetter, drier, and severely dry hydrology. Historically severe floods occurred in 1861 and 1862, which created a 300-square-mile lake in the Central Valley and forced the state legislature to abandon Sacramento for 18 months. The flooding was immediately followed by a severe and prolonged drought that gripped the state through the winter of 1865. Botanists believe that the episodic flooding and droughts in the mid-19th century facilitated the replacement of native vegetation by hardier invasive plants throughout the Central Valley (Burcham 1981).

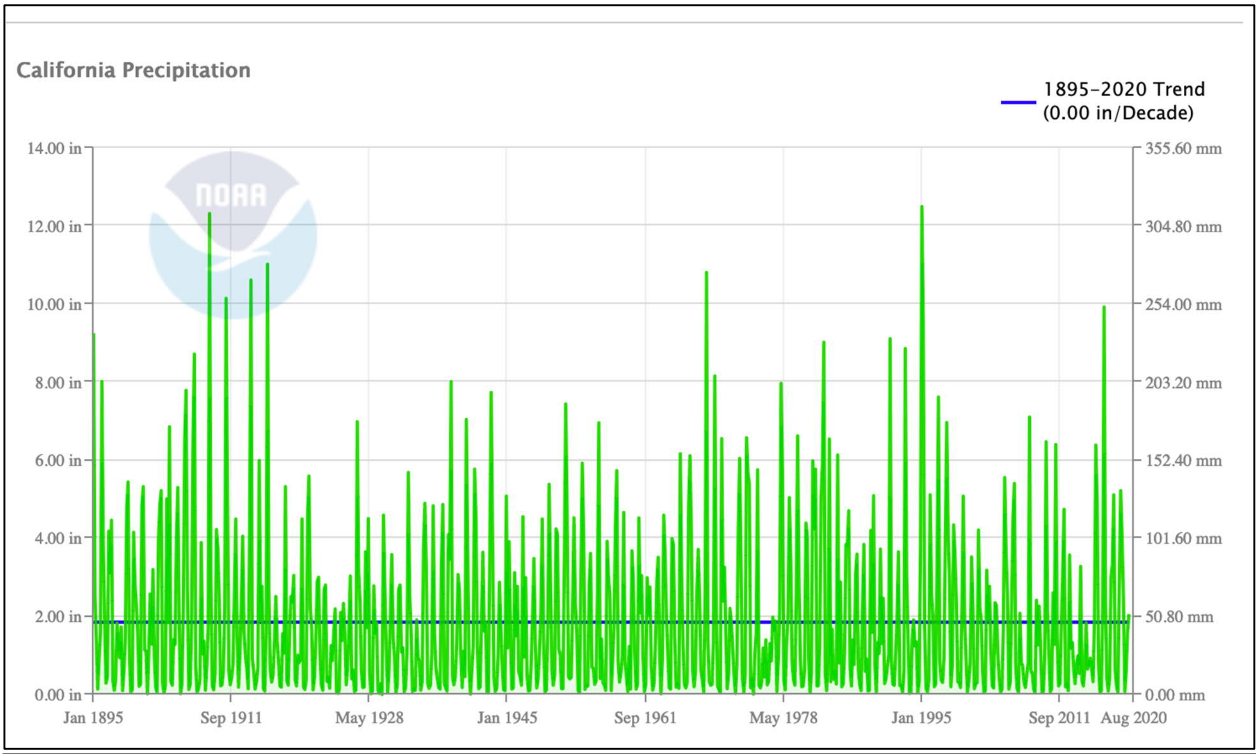
Figure 4.9-EE: U.S. Drought Monitor for California



Since 2017, no part of the state has been in an exceptional drought (D4). In ~~June~~ *October* 2020, the USDM stated that about *22.9%* ~~*17.8%*~~ of California was in D2 condition, and *12.7%* ~~*3%*~~ was in D3 condition. All of these locations extended north from the San Francisco Bay Area to the Oregon border. The USDM indicated that *31%* ~~*25%*~~ of the state was in D1 condition, and *17.5%* ~~*11.5%*~~ was considered to be abnormally dry (D0). ~~*All*~~ *Almost all* of these locations were north *and east* of the Project Area. As shown in Figure 4.9-DD, conditions similar to or more severe than those identified for 2020 have occurred repeatedly in California over the USDM's 20-year period of record (NIDIS 2020).

Climate data in California from pre-historic times also shows dramatic variability. Paleoclimate analyses based on tree rings and other climate proxies have indicated that, from 800 to 1300, the western United States experienced prolonged periods in which a much greater land area was subject to decades of drought. Recent research and media reports have referred to these periods as "megadroughts." Severe and expanded droughts occurred with less frequency to about the mid-1600s, and continued to occur, but with less frequency, than in earlier periods. As discussed above, the data indicate that there was an extended drought in the mid-19th century, which directly and severely affected California, including native state vegetation. Another western regional drought, which, as shown in Figure 4.9-FF, also affected California, occurred in the early years of the 21st century.

Figure 4.9-FF: NOAA Monthly Precipitation and Trend, California 1895-2020



Source: NOAA, National Centers for Environmental Information,
Climate at a Glance: California, 1895-2020, https://www.ncdc.noaa.gov/cag/statewide/time-series/4/pcp/all/1/1895-2020?trend=true&trend_base=10&begtrendyear=1895&endtrendyear=2020

These results indicate that, at present, it is not possible to conclusively determine how the timing and intensity of droughts may affect water supplies in the state over the next several decades. The

The extent to which California water supplies and groundwater recharge can significantly vary over brief periods of time, including a single season, is demonstrated by ~~T~~*t*he April 2020 Annual Report submitted to the DWR by the Groundwater Sustainability Agencies (GSAs) *for the* KCS, *which* provides groundwater storage information for from 2016-2019 that is consistent with the significant improvement in the state and Project Area hydrology since the peak drought period in July 2014. The annual report states that water year 2016 was a dry water year type (as defined by the DWR and in the SGMA regulations) and KCS groundwater in storage declined by 1,229,970 AF. Water year 2017 was a wet water year type, and storage increased by 1,722,971 acre-feet. Water year 2018 was a below normal water year type, and groundwater storage declined by 636,030 acre-feet. Water year 2019 was a wet water year type and storage increased by 851,260 acre-feet. Groundwater in storage over the four-year period from water year 2016 to water year 2019 increased by a total of 708,231 acre-feet, or by an average of 177,058 AFY. In contrast, groundwater in storage declined by an average of -277,114 AFY from water year 1995 to water year 2014 (KCSGSAs 2020). *The Annual Report indicates that, immediately following the most recent drought, precipitation increased during water year 2016 to 2019 in amounts sufficient to* *increase annual average groundwater in storage by over 177,000 AFY compared with the long-term trend of annual depletion at more than -277,000 AFY from water year 1995 to water year 2014. A series of very wet years, or annual average precipitation increases projected by certain studies due to climate change (e.g., Allen and Luptowitz 2017) could significantly increase recharge rates in the Project Area above historical levels.*

Oil and Gas Production and Water Resources

Overview

Groundwater that naturally exists in oil and gas reservoirs is brought to the surface when oil and gas are extracted from these reservoirs. This water is known as "produced water." Water is also used for various purposes to conduct oil and gas exploration and production activities in the Project Area. This section summarizes the existing amounts, sources, and uses of water for oil and gas exploration and production. Urban and agricultural water supply and demand planning in California is generally analyzed with reference to AF, which is the amount of water that covers 1 acre to a depth of 1 foot and contains about 325,851 gallons. For clarity and comparison purposes, the 2015 FEIR and this SREIR discuss oil and gas production and exploration water use and supply in terms of AF, although the industry typically reports fluid volumes in terms of "barrels." There are 42 gallons in a barrel, and about 7,758 barrels in an AF. Potential impacts to surface or groundwater quality and other hydrological resources that could occur from the extraction, conveyance, use, and disposal of water resources are discussed in Section 4.9.4, Impacts and Mitigation Measures. Potential water supply impacts are discussed in Section 4.17, Utilities and Service Systems, of the 2015 FEIR and this SREIR. Potential subsidence, seismic, and other geological impacts are discussed in Section 4.6, Geology and Soils of the 2015 FEIR (SREIR Volume 3).

Oil-bearing formations in the Project Area include a mixture of usually saline or other poor-quality groundwater and hydrocarbons. Production wells extract a mixture of water and hydrocarbons that is separated in surface facilities, typically a series of tanks or "tank batteries," where lighter oil and gas compounds are isolated and skimmed from the heavier water. Residual water generated by the hydrocarbon separation process is generally referred to as "produced water" in the context of oil and gas exploration and production. As oil fields mature in the Project Area, the ratio of produced water to extracted hydrocarbon resources has tended to increase, in part because the volume of the hydrocarbon deposits remaining in the subsurface formations has been reduced by prior extraction, and also because of the injection of steam or water to mobilize heavier, more viscous deposits for pumping to the surface.

Certain oil and gas exploration and production activities require the use of higher quality water supplies than can typically be obtained from produced water sources. Water for these activities comes from a variety of sources, including groundwater and imported or other surface water that could also be used for agricultural or domestic purposes, including municipal and industrial purposes. These activities include supplemental steam generation for enhanced oil recovery (EOR) use, drilling and cementing processes for new well construction, well stimulation treatments, and well maintenance and abandonment. Water sources (other than produced water) that are used for oil and gas exploration and production in the Project Area, including domestic and irrigation quality water, are collectively referred to as "municipal and industrial (M&I) water" or "domestic and irrigation quality" water.

The following sections discuss oil and gas produced water generation and use for the Project Area and within each of the three subareas which reflect the Project Area's dominant hydrogeology. As discussed above under Water Supply Baseline Update, in addition to the analysis of the Project Area and subareas, each GSP and management area plan adopted for any portion of the Project Area was reviewed to determine the extent to which oil and gas operations were identified as a significant factor affecting the achievement of SGMA objectives. None of the adopted GSPs and management areas plans within the Project Area identify oil and gas operations as a significant factor affecting the achievement of any of the SGMA objectives. Almost all of the GSPs and management area plans explicitly exclude oil and gas operational areas and exempted aquifers, from SGMA-regulated groundwater basins. Several identify the potential use of treated and/or blended oil and gas produced water as a potential source of new imported water that would increase available supplies for agricultural irrigation purposes and reduce potential groundwater demand over time. For more information concerning the discussion of oil and gas activities, including produced water generation and use in each adopted GSP and management area plan in the Project Area, see Project Area Groundwater Sustainability Plans and Oil and Gas Activities, below, and Appendix D of this SREIR.

Figure 4.9-7 and Table 4.9-1 show the amount of oil and produced water generated in the Project Area from 2002 through 2013. Oil production in the Project Area declined from about 25,630 AF (198.8 million barrels) in 2002 to 18,260 AF (141.6 million barrels) in 2013. Over the same period, produced water increased from about 149,400 AF to 231,250 AF by 2013.

Table 4.9-1: Project Area 2012 Oil and Gas Exploration and Production - Water Supply and Demand

Water Supplied (AF)	
Produced Water	234,959
M&I Water	8,778
TOTAL	**243,737**
Water Use	
Treated Produced Water (AF)	
EOR Water and Steam Injections, Pressure Maintenance and Well Pulling	88,668
Coil Tubing, Dust Control, Surface Facility Construction	144
Oil and Gas Produced Water Reuse	88,812
Agricultural Reuse	38,658
Subtotal: Produced Water Reuse	**127,470**

Table 4.9-1: Project Area 2012 Oil and Gas Exploration and Production - Water Supply and Demand

M&I Water	
New Well Construction (Drill Mud + Well Stimulation)	589
Maintenance (Mud Services + Cementing)	61
Maintenance (Acidizing + Coil Tubing)	52
Maintenance (Well Pulling + Domestic Water)	594
Well Abandonment	202
Steam Production	7,279
Oil and Gas M&I Water Demand	8,778
Subtotal: Oil and Gas Water Demand, M&I and Produced Water	**97,590**
Injection Well Disposal	84,571
Produced Water Land Disposal	30,931
Subtotal: Oil and Gas Produced Water Waste Disposal	**115,502**

Key:
AF = acre-feet

Figure 4.9-7 shows that the ratio of produced water to oil recovered from Project Area oil and gas activities increased from just under 6 units (gallons, barrels, or AF) of produced water for each unit of oil recovered in 2002 to nearly 13 units of produced water for each unit of oil recovered in 2012 and 2013. The total amount of produced water extracted from hydrocarbon-bearing formations in the Project Area during 2012 was about 234,959 AF (Table 4.9-1).

Produced water comprises the single largest source of water supply for oil and gas exploration and production activities in the Project Area. After the hydrocarbons are separated from the mixture of oil and water that is pumped from a well, the produced water is conveyed by pipelines or by truck from the tanks and separation facilities for use in other oil and gas operations, including reinjection into oil-bearing formations in the form of steam or water to mobilize hydrocarbon deposits. EOR is a production technique used to increase the mobility of oil, most commonly through steam injection techniques that reduce the viscosity of the hydrocarbons and allow produced fluids to flow. There are three major types of EOR operations: thermal (steam flood, cyclic steam, and in situ combustion); carbon dioxide or other gas (miscible and immiscible); and chemical/polymer flooding (alkaline flooding or micellar-polymer flooding). Steam flooding involves injecting a continuous rate of steam into the reservoir through dedicated wells (steam injectors) to heat heavier oil to the point it can flow to the wellbore (producers). Cyclic steam involves intermittent injection of steam through producing wells. Water flooding is the process of injecting water into the reservoir via an injection well for the purposes of sweeping the hydrocarbons to a nearby production well where they can be recovered to the surface.

Produced water used for EOR purposes, particularly in the form of steam, is often subject to treatment in oil field facilities to reduce certain constituent levels, such as calcium or magnesium, and to "soften" or reduce the hardness of the produced water prior to heating. Produced water is also used for well maintenance activities, including use of coil tubing spooled into a wellbore, dust control, and surface facility construction. About 89,000 AF of produced water was reinjected into oil-bearing formations for EOR or used for maintenance and construction purposes in the Project Area during 2012 (Table 4.9-1).

In addition, produced water is treated and conveyed to water districts and blended for irrigation purposes. About 38,658 AFY of treated produced water from wellfields in the Eastern Subarea was supplied to and reused for agricultural irrigation by the CWD (37,107 AF) and for other agricultural irrigation (1,551 AF) in 2012 (see 2015 FEIR Appendix T-1, Section 4.3.6.2). The produced water is treated by oil field facilities to remove residual hydrocarbons and certain other constituents and is mixed with other district water supplies to reduce the total dissolved solid (TDS) or salt concentrations prior to irrigation use.

Produced water that is not reused for oil field operations, including EOR, maintenance, or construction, or that is not treated and supplied to other users for agricultural irrigation, is disposed by oil field operators in surface impoundments (ponds) in accordance with Waste Discharge Requirements (WDRs) issued by the Central Valley Regional Water Quality Control Board (CVRWQCB) or is injected into Class II injection wells (discussed in more detail below) permitted by the California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR). Effective January 1, 2020, DOGGR was replaced by the California Geologic Energy Management Division (CalGEM) of the state Department of Conservation. Except where noted, references to DOGGR prior to the effective date for CalGEM are retained, but DOGGR no longer exists and CalGEM is the state's primary regulatory entity for oil and gas activity (CalGEM 2020a). The state's oil and gas regulatory districts were also reorganized, and the Project Area is within the CalGEM Inland District (CalGEM 2020b). About 30,931 AF of produced water was disposed into surface ponds and 84,500 AF of produced water was disposed by injection into Class II wells in the Project Area during 2012 (Table 4.9-1).

In 2012, about 8,778 AF of M&I water was used for oil and gas exploration and production in the Project Area. Most of these supplies were used for new well construction, well stimulation treatments, and supplemental EOR steam generation (Table 4.9-1). As discussed in Section 4.17, Utilities and Service Systems, oil and gas producers obtain M&I water from a variety of sources that vary from year to year, including private groundwater wells owned by oil and gas operators, Project Area water districts that have contracted to supply certain oil and gas operators with M&I or similar quality water, or by spot purchases from Project Area water users on an as-needed and as-available basis.

Table 4.9-1 summarizes the primary sources of oil and gas exploration and production water supply and water use in the Project Area during 2012.

Table 4.9-1 shows that total oil and gas production and exploration water demand in the Project Area during 2012 was about 97,590 AF, including 88,812 AF of produced water used for EOR and coil tubing, dust control, and surface facility construction purposes and 8,778 AF of M&I water that was used for new well construction, well stimulation treatments, supplemental EOR steam generation, maintenance, abandonment, and oil field domestic and sanitary water uses. Produced water accounted for about 91% and M&I water accounted for 9% of total oil and gas production and exploration demand in 2012. About 115,502 AF of produced water was disposed of as waste in the Project Area during 2012, of which 73% (84,571 AF) was injected into Class II injection wells and 27% (30,931 AF) was discharged into percolation or evaporation ponds. About 38,658 AF of produced water generated primarily from the Kern River and adjacent oil fields in the Eastern Subarea was treated, blended with other water supplies, and used by the CWD and other users for agricultural irrigation in 2012.

Project Subarea Overview

This section summarizes the primary sources of oil and gas exploration and production water supply and water use and disposal in each of the three Project Subareas during 2012. *Additional information concerning potential oil and gas impacts discussed in each of the GSPs and management area plans adopted in the Project Area, which cover locations within the Project Area and subareas that reflect historic patterns of water use and management, is provided under Project Area Groundwater Sustainability Plans and Oil and Gas Activities, below, and in Appendix D of this SREIR.*

Western Subarea

Table 4.9-2 summarizes the primary sources of oil and gas exploration and production water supply and water use and disposal in the Western Subarea during 2012.

Table 4.9-2: Western Subarea 2012 Oil and Gas Exploration and Production Water Supply and Demand

Water Supplied (AF)	
Produced Water	131,341
M&I Water	8,358
TOTAL	**139,699**
Water Use (AF)	
Treated Produced Water	
EOR Water and Steam Injections, Pressure Maintenance and Well Pulling	75,322
Coil Tubing, Dust Control, Surface Facility Construction	97
Oil and Gas Produced Water Reuse	75,419
Agricultural Reuse	0
Subtotal: Produced Water Reuse	**75,419**

Table 4.9-2: Western Subarea 2012 Oil and Gas Exploration and Production Water Supply and Demand

M&I Water	
New Well Construction (Drill Mud + Well Stimulation)	472
Maintenance (Mud Services + Cementing)	40
Maintenance (Acidizing + Coil Tubing)	35
Maintenance (Well Pulling + Domestic Water)	397
Well Abandonment	134
Steam Production	7,279
Oil and Gas M&I Water Demand	8,357
Subtotal: Oil and Gas Water Demand, M&I and Produced Water	**83,776**
Injection Well Disposal	40,482
Produced Water Land Disposal	19,545
Subtotal: Oil and Gas Produced Water Waste Disposal	**60,027**

Source: Table 28, Appendix T-1, 2015 FEIR,
Notes:
Includes a water balance closure factor for the net difference between estimated water inputs and outputs of -4,104 AF.
All values subject to rounding and may vary slightly from Table 28.
Key:
AF = acre-feet

Table 4.9-2 shows that total oil and gas production and exploration water demand in the Western Subarea during 2012 was about 83,776 AF, including 75,419 AF of produced water reused for EOR and coil tubing, dust control, and surface facility construction purposes and 8,358 AF of M&I water for new well construction, well stimulation treatments, supplemental EOR steam generation, maintenance, abandonment, and oil field domestic and sanitary water uses. Produced water accounted for about 90% and M&I water accounted for 10% of total oil and gas production and exploration demand in the Western Subarea during 2012. About 60,027 AF of produced water was disposed as waste in the Western Subarea during 2012, of which 67% (40,482 AF) was injected into Class II injection wells and 33% (19,545 AF) was disposed into percolation or evaporation ponds. No treated produced water was used for agricultural irrigation in the Western Subarea.

Central Subarea

Table 4.9-3 summarizes the primary sources of oil and gas exploration and production water supply and water use and disposal in the Central Subarea during 2012.

Table 4.9-3: Central Subarea 2012 Oil and Gas Exploration and Production Water Supply and Demand

Water Supplied (AF)	
Produced Water	2,884
M&I Water	63
TOTAL	**2,947**
Water Use (AF)	
Treated Produced Water	
EOR Water and Steam Injections, Pressure Maintenance and Well Pulling	818
Coil Tubing, Dust Control, Surface Facility Construction	2
Oil and Gas Produced Water Reuse	820
Agricultural Reuse	0
Subtotal: Produced Water Reuse	**820**
M&I Water	
New Well Construction (Drill Mud + Well Stimulation)	42
Maintenance (Mud Services + Cementing)	2
Maintenance (Acidizing + Coil Tubing)	1
Maintenance (Well Pulling + Domestic Water)	12
Well Abandonment	6
Steam Production	0
Oil and Gas M&I Water Demand	63
Subtotal: Oil and Gas Water Demand, M&I and Produced Water	**883**
Injection Well Disposal	2,170
Produced Water Land Disposal	189
Subtotal: Oil and Gas Produced Water Waste Disposal	**2,359**
TOTAL	**2,947**

Source: Table 28, Appendix T-1, 2015 FEIR
Notes:
Includes a water balance closure factor for the net difference between estimated water inputs and outputs of -294 AF.
All values subject to rounding and may vary slightly from Table 28.
Key:
AF = acre-feet

Table 4.9-3 shows that total oil and gas production and exploration water demand in the Central Subarea during 2012 was about 883 AF, including 820 AF of produced water reused for EOR and coil tubing, dust control, and surface facility construction purposes, and 63 AF of M&I water for new well construction, well stimulation treatments, maintenance, abandonment, and oil field domestic and sanitary water uses. Produced water accounted for about 93% and M&I water accounted for 7% of total oil and gas production and exploration demand in the Central Subarea during 2012. About 2,359 AF of produced water was disposed as waste in the Central Subarea Area during 2012, of which 92% (2,170 AF) was injected into Class II injection wells and 8% (189 AF) was disposed into percolation or evaporation ponds. No treated produced water was used for agricultural irrigation in the Central Subarea.

Eastern Subarea

Table 4.9-4 summarizes the primary sources of oil and gas exploration and production water supply and water use and disposal in the Central Subarea during 2012.

Table 4.9-4: Eastern Subarea 2012 Oil and Gas Exploration and Production Water Supply and Demand

Water Supplied (AF)	
Produced Water	100,734
M&I Water	357
TOTAL	**101,091**
Water Use (AF)	
Treated Produced Water	
EOR Water and Steam Injections, Pressure Maintenance and Well Pulling	12,528
Coil Tubing, Dust Control, Surface Facility Construction	45
Oil and Gas Produced Water Reuse	12,573
Agricultural Reuse	38,658
Subtotal: Produced Water Reuse	**51,231**
M&I Water	
New Well Construction (Drill Mud + Well Stimulation)	74
Maintenance (Mud Services + Cementing)	19
Maintenance (Acidizing + Coil Tubing)	16
Maintenance (Well Pulling + Domestic Water)	186
Well Abandonment	62
Steam Production	0
Oil and Gas M&I water demand	357
Subtotal: Oil and Gas Water Demand, M&I and Produced Water	**12,930**

Table 4.9-4: Eastern Subarea 2012 Oil and Gas Exploration and Production Water Supply and Demand

Injection Well Disposal	41,919
Produced Water Land Disposal	11,197
Subtotal: Oil and Gas Produced Water Waste Disposal	**53,116**
TOTAL	**101,091**

Source: Table 28, Appendix T-1, 2015 FEIR
Notes:
Includes a water balance closure factor for the net difference between estimated water inputs and outputs of -3,613 AF
All values subject to rounding and may vary slightly from Table 28.
Key:
AF = acre-feet
EOR = enhanced oil recovery
M&I = municipal and industrial

Table 4.9-4 shows that total oil and gas production and exploration water demand in the Eastern Subarea during 2012 was about 12,931 AF, including 12,574 AF of produced water reused for EOR and coil tubing, dust control, and surface facility construction purposes, and 357 AF of M&I water for new well construction, well stimulation treatments, maintenance, abandonment, and oil field domestic and sanitary water uses. Produced water accounted for about 97% and M&I water accounted for 3% of total oil and gas production and exploration demand in the Eastern Subarea during 2012. About 53,116 AF of produced water was disposed as waste in the Eastern Subarea Area during 2012, of which 79% (41,919 AF) was injected into Class II injection wells, and 21% (11,197 AF) was disposed into percolation or evaporation ponds. About 38,658 AF of treated produced water was used for agricultural irrigation in the Eastern Subarea by the CWD and other users in 2012, representing about 75% of the total amount of produced water recycled in the Eastern Subarea.

Well Stimulation

Well stimulation treatments (including hydraulic fracturing, acid fracturing, and acid matrix stimulation) enhance oil and gas production or recovery by increasing the permeability of the geologic formation where hydrocarbons occur (California Code of Regulations [CCR] Section 1761(a)). Well stimulation treatments do not include routine well cleanout work, routine maintenance, routine removal of formation damage due to drilling, bottom hole pressure surveys, or routine activities that do not affect the integrity of the well or the formation. The well stimulation treatments fracture or chemically alter a geologic formation so that hydrocarbon deposits collect and concentrate for extraction. A single well may be subject to more than one stimulation treatment depending on the underlying formation and hydrocarbon deposit. Well stimulation treatments subject to the interim and final state regulations include hydraulic fracturing, acid matrix stimulation, and acid fracturing. The use of acid for routine well cleanout, maintenance, and removal of formation damage is not regulated as a form of well stimulation under state law. Well stimulation may be conducted within new wells or during the reworking of an existing well to improve performance.

Hydraulic fracturing (also known as hydrofracturing, "fracking," or "fracing") is the injection of a mixture of water, chemicals, and substances (primarily silica sand) called "proppants" into a well at pressures greater than the fracturing pressure of the oil-bearing formation. Hydraulic fracturing causes microscopic fractures to propagate away from the well boring and increases the surface area of the geologic formation that is connected with the well. Proppants are deposited into the fractures during the stimulation process to ensure that the fractures remain open and collect oil or gas. Oil or natural gas flows through the fractures to the well for surface recovery (DOGGR 2013). As discussed below, the average fracturing operation in California uses about 0.38 AF of water compared with much greater amounts of water used in many other parts of the country. California operations require smaller volumes of water because operators in this state fracture in relatively shallow vertical wells (usually fewer than 2,000 feet deep), with shorter treatment intervals than the horizontal wells that are more common elsewhere. Hydraulic fracturing also uses cross-linked gels in California compared to less viscous gels and slick-water in other parts of the country that require a greater volume of water to complete the fracturing process (CCST 2015).

Acid fracturing and acid matrix stimulation inject acid into the oil-bearing formation to increase permeability. An acid fracturing treatment involves pumping fluids into a well to enhance the flow and production of oil or gas by dissolving carbonate reservoir rock along existing fractures, thereby increasing permeability and fluid flow. An acid matrix stimulation involves pumping fluids into a siliciclastic reservoir formation utilizing the chemical properties of the pumped fluids to increase the permeability of the reservoir near the well. Increasing permeability in the reservoir increases the flow and production of oil and gas. The primary mechanism responsible for increasing permeability as a result of acid matrix stimulation is the dissolution of drilling mud in the pores of the reservoir near the well. Acid matrix stimulation is utilized in some oil fields in the Project Area on a limited basis (CCST 2014).

California's Senate Bill (SB) 4 well stimulation regulations require that all oil and gas well operators file notices with CalGEM and provide notice to neighboring landowners at least 30 days before a stimulation treatment is conducted. Within 60 days after a well stimulation treatment is completed, a disclosure must also be filed with CalGEM identifying the source, volume, composition, and disposition of well stimulation fluids, including, but not limited to, hydraulic fracturing fluids, acid well stimulation fluids, and flowback fluids. As of March 24, 2015, 1,367 notices of proposed well stimulation treatments and 673 disclosures for completed treatments were available on the online CalGEM database maintained under the new state regulations. As shown on Figure 4.9-8, almost all of the stimulation notices and treatment disclosures were located in the Western Subarea, except for 23 notices with disclosures in the Rose field, five notices in the Shafter North field, and one notice with one disclosure in the Stockdale field. The Rose, Schafter North, and Stockdale fields are located in the Central Subarea. No well stimulation notices or disclosures were filed for the Eastern Subarea. Additional information concerning well stimulation notices and permitting in the state is available at the CalGEM Well Stimulation Treatment website (CalGEM 2020c).

In February 2015, the California Council on Science and Technology (CCST) published the first volume of a three-volume analysis of well stimulation activity and potential impacts in California (CCST 2015), as required by newly adopted California well stimulation laws and regulations. Appendix T of the CCST study summarized available information for 1,986 well stimulation notices and disclosures that occurred in the Project Area (CalGEM District 4) from March 2011 to May 2014. As shown in Table 4.9-5, during this period, hydraulic fracturing accounted for 1,687 well stimulation treatments, acid matrix treatments were used in 295 wells, and acid fracturing was used in four wells.

Table 4.9-5: Summary of Well Stimulation Information Compiled by CCST for Project Area, March 2011 to May 2014

	Number of Treatments	Average Water Use per Treatment (AF)
Hydraulic Fracturing	1,687	0.40
Acid Matrix	295	0.24
Acid Fracturing	4	0.14
TOTAL	**1,986**	**0.38**

Source: CCST 2015, 2015 FEIR Appendix T-1
Key:
AF = acre-feet

The CCST data also indicate that the average well stimulation treatment in the Project Area used about 0.38 AF (122,130 gallons) of water. Hydraulic fracturing treatments generally used more water (0.4 AF on average) than acid matrix or acid fracturing treatments (0.24 to 0.14 AF on average). About 744 AF of water was used in the Project Area for all well stimulation activities over March 2011 to May 2014, an average of less than 250 AFY. These estimates are consistent with statewide well stimulation data compiled by CalGEM for the period January to September 2014, which indicate that 433 treatments used 123.34 AF of water, an average of about 0.29 AF per treatment. The CalGEM data also estimated that 66% of the statewide well stimulation treatment water supply during January to September 2014 was obtained from surface water sources, including imported supplies, 25% was obtained from groundwater wells, and about 9% was obtained by reusing produced water (DOGGR 2015a, Table 10.14-7).

In June of 2015, Kern County completed a study with the following objectives:

- Identify differences in the most prominent plays across the nation;
- Identify the subsequent drilling and stimulation techniques that would apply to wells being drilled in Kern County as compared to those in other shale plays and conventional oil and gas operations conducted across the nations; and
- Highlight the differences between them.

The study is attached as Appendix U in the 2015 FEIR. Three general areas of impact (water quality, seismic, and radiological impacts) were examined in the study. One key factor identified in the study was that drilling in Kern County that is associated with hydraulic fracturing is vertical (or follows conventional methods). In the majority of other oil and gas fields in the Country where hydraulic fracturing takes place, the method is associated with horizontal drilling or unconventional methods. Horizontal drilling presents more vulnerabilities in drilling and well construction for a variety of reasons including the potential of intersecting existing fractures and faults that could serve as unintended fluid or gas pathways.

Water quality impacts, although limited in scope, have been identified associated with unconventional gas development in the Marcellus and Barnett Shales. Limited, detailed investigation appears to associate impacts with well issues rather than hydraulic fracturing itself. Although characteristics of these vary with respect to the Monterey Shale and conventional oil and gas plays in Kern County, it appears that well construction may be a more important factor for potential impacts to water quality.

Other comparisons that speak to the likelihood of water quality impacts can be made between the Kern County plays and the Marcellus and Barnett Shales. The following bullets are categorized into factors that are more protective of water quality in the Kern County plays versus those that are less protective:

Comparison of factors influencing potential for water quality impacts:

- Distance between source shale and base of freshwater aquifer is greater in Kern County than in the Marcellus and Barnett Shale plays.
- Both oil and gas are being produced in Kern County. The Marcellus and Barnett Shales produce gas only, which is more mobile than oil.
- Significantly less water is used in conventional drilling and production in Kern County than in the Marcellus and Barnett Shales.

Several studies by various authors indicate that induced-seismic events are more commonly associated with wastewater disposal/injection than with hydraulic fracturing. In addition, induced-seismic events appear to be more common when wastewater is injected into bedrock rather than in sedimentary formations with higher porosities and permeabilities. In California, wastewater disposal/injection is in sedimentary formations and, unlike other parts of the United States, increased induced-seismicity has not been observed with hydraulic fracturing and other unconventional drilling methods.

The development of unconventional natural gas in the Marcellus Shale in Pennsylvania was found to have the potential to exacerbate several pathways for entry of radon into buildings. The U.S. Geological Survey (USGS) reported 91,020 Becquerels per cubic meter ($Bq/^{m3}$) as the median radium concentration in produced water from Marcellus wells (Rowan et al. 2011), which is nearly 500 times the federal drinking water limit (185 Bq/m^3) and exceeds the industrial discharge limit of 2,220 Bq/m^3. Radon can collect in porous geological formations as well as in natural gas production wells (Gogolak 1980). Shales tend to contain higher concentrations of uranium (3.7 to 40 parts per million [ppm]) than other geologic formations. Natural gas production wells completed in shales would therefore be expected to have higher concentrations of radon in their natural gas (Gogolak 1980). This phenomenon was reported by USGS in preliminary data from 11 wellheads in Pennsylvania ranging from 37 to 2,923 Bq/m^3 (Rowan and Kraemer 2012), which suggests that shale gas may have higher radon levels than other natural gas sources (Casey et al. 2015).

In Kern County, CalGEM (then DOGGR) surveyed various oil and gas facilities for naturally occurring radioactive material (NORM) in 1994. In its 1996 report, CalGEM made the following conclusions:

- Facilities with radiation levels greater than 15 picocuries per gram (pCi/g) should be evaluated to determine if protective measures are necessary to control the ingestion or inhalation of NORM by workers;
- Simple protective measures should be taken, where necessary, to minimize exposures and keep exposures as low as reasonably achievable;
- In gas processing facilities where separation of the more volatile fractions occur, personnel should not remain for long periods near the propanizer reflux pumps while those pumps are in operation; and
- American Petroleum Institute Bulletin E2, Bulletin on Management of Naturally Occurring Radioactive Materials in Oil and Gas Production, should be adhered to by all operators, as necessary, and used as the primary guidance document. However, the appropriate state agency should be contacted before any disposal of NORM occurs.

CalGEM found in its study of NORM that radiation readings exceeding 15 pCi/g (requiring further evaluation) were noted in District 4, which includes Kern County. Radium isotopes were detected at concentrations up to 1,182 pCi/g with the elevated results detected in pipe scale, soil, and spent resin (CA DOC 1996).

Project Area Groundwater Sustainability Plans and Oil and Gas Activities

As discussed in Section 4.9-3, Regulatory Setting, the SGMA requires that adopted GSPs for applicable groundwater basins or subbasins must avoid undesirable results and achieve sustainable groundwater management within 20 years. The SGMA defines “undesirable results” to mean:

- Chronic lowering of groundwater levels (not including overdraft during a drought, if a basin is otherwise managed);
- Significant and unreasonable reductions in groundwater storage;
- Significant and unreasonable seawater intrusion;
- Significant and unreasonable degradation of water quality;
- Significant and unreasonable land subsidence; and

- Surface water depletions that have significant and unreasonable adverse impacts on beneficial uses.

The Project Area is located in the inland Central Valley of California and seawater intrusion is not a significant issue for the region.

The GSPs for the Tule subbasin, the Tulare Lake subbasin, and the Cuyama Valley basin (see Figure 4.9-CC) have been adopted for groundwater basins that are located almost entirely outside of the Project Area and Kern County. None of the small portions of these GSPs underlie an existing administrative oil field boundary or an oil and gas Core Area in the Project Area. The applicable GSPs for these basins were reviewed for references to oil and gas activities. None of these GSPs indicate that oil and gas activities, and specifically oil and gas operations within the Project Area, would significantly affect the attainment of SGMA objectives within each plan.

As shown in Figure 4.9-AA, the White Wolf subbasin is located in the southern part of the Project Area and was separated from the KCS in a basin boundary modification approved by DWR in 2016. The technical study prepared in support of the boundary modification indicates that the White Wolf subbasin had an approximate water inflow of 32,000 AFY, an outflow of about 28,500 AFY and a net positive change in groundwater storage of 3,500 AFY. The technical study noted that oil and gas activities have historically occurred and continue to occur in the subbasin, including the production of 160,000 barrels of oil and 860,000 million cubic feet of gas production in 2014 (EKI 2016). The DWR reduced the basin's priority to medium from the high priority and critically overdrafted designation applicable prior to the approved basin boundary modification. A GSP for the White Wolf subbasin is not required until January 31, 2022, and no GSP has been adopted for the subbasin.

A small portion of the low-priority Carizzo Plain basin extends into the southwest portion of the Project Area. As shown in Figure 4.9-AA, there are no administrative oil field boundaries or Core Areas in this location. The Carizzo Plain basin does not require a GSP, and no GSA has been formed for the potential development of a GSP in accordance with the SGMA. As shown in Figure 4.9-AA, a portion of the Kettleman Plain subbasin extends into the northwest portion of the Project Area and underlies a small amount of the administrative oil fields and Core Areas in the Project Area. Oil and gas activities have historically occurred in the Kettleman Plain subbasin for several years. The Kettleman Plain basin is designated by the DWR as lower priority, does not require a GSP, and no GSA has been formed for the potential development of a GSP in accordance with the SGMA.

As shown in Figure 4.9-AA, the KCS covers approximately 1.8 million acres and underlies the vast majority of the administrative oil fields and Core Areas in the Project Area and each of the three Project Subareas. As shown in Figure 4.9-CC, as of January 31, 2020, the KCS is covered by five GSPs, some of which include areas regulated by multiple GSAs. The largest GSP is the KGA GSP, which includes about 1.2 million acres of the KCS. Fifteen management area plans have been adopted within the KGA GSP. The second largest GSP is the KRGSP, which covers about 230,830 acres and includes the City of Bakersfield, the Kern Delta Water District, Kern County Water Agency Improvement District No. 4, the North of the River Municipal Water

District/Oildale Mutual Water Company, and the East Niles Community Services District and the Greenfield GSA. The Henry Miller GSP is located to the west of the KRGSP in the Western Subarea of the Project Area. The Buena Vista GSP covers portions of the Western and Central Subareas in the northern portion of the Project Area. The Olcese GSP is located on the eastern edge of the Eastern Subarea near the Kern River.

The SGMA requires that the KGA GSP, including the 15 management area plans adopted within the KGA GSP, the KRGSP, the Henry Miller GSP, the Buena Vista GSP and the Olcese GSP be managed in a coordinated manner and achieve sustainable groundwater management within 20 years in accordance with the KCS Coordination Agreement and consistent with the coordinated water budget. The coordinated water budget indicates that proposed SGMA Projects must be implemented in the KCS to achieve these objectives. The Coordination Agreement and the coordinated water budget are discussed in more detail in Section 4.17.2, Utilities and Service Systems, Environmental Setting, in this SREIR. Each GSP and management area plan describes how water supplies in the applicable planning area would be managed in collaboration with the other GSPs and management areas in the KCS to ensure that the basin-wide SGMA requirements are achieved. The GSPs and management area plans correspond with historically-defined water districts and discrete water management operational areas within the Project Area and each Project Subarea.

The GSPs and management area plans for the KCS provide information about the potential interaction between SGMA management objectives and oil and gas operations prepared by professional geologists and engineers as required by the SGMA for applicable water districts and water management entities in the Project Area. The plans consider potential oil and gas effects on the avoidance of undesirable results in the KCS, including chronic lowering of groundwater levels and significant and unreasonable reductions in groundwater storage, degradation of water quality, land subsidence, and surface water depletions adverse impacting beneficial uses The following discussion summarizes this information for the KGA GSP and the 15 management area plans in the KGA GSP, the KRGSP, the Henry Miller GSP, the Olcese GSP and the Buena Vista GSP.

KGA GSP and Management Area Plans

The KGA GSP is an “umbrella” GSP that covers approximately 1.2 million acres of the KCS and includes 15 management area plans. The locations of the KGA member agencies that are implementing the management area plans are shown in Figure 4.9-DD and include areas where established water districts have operated for decades in relevant portions of the Western, Central and Eastern Project Subareas.

Section 2 of the KGA GSP states that “active oil and gas aquifers and exempted aquifers are not a part” of the KCS “groundwater basin for beneficial use.” The “lateral and vertical boundaries” of the KCS are defined as the shallowest of “depth to producible minerals or hydrocarbons, depth to and aerial extent of exempted aquifers [and] the depth at which groundwater cannot now or in the future serve as a source of drinking water.” To illustrate these boundaries, the KGA GSP states that “water bearing zones below the depth to producible hydrocarbons are not within the groundwater basin; likewise, water bearing zones below an exempted aquifer are not within the groundwater basin. In some parts of the Subbasin the lateral and bottom boundaries of the groundwater are subject to depths to producible hydrocarbons and extent of depths to aquifer exemptions. As described above, any water bearing zone below these three criteria are outside of the groundwater Subbasin."

The KGA GSP indicates that salinity and TDS are generally higher at shallower levels in the west side of County which is generally the Western Subarea of the Project Area. The plan states that a 2018 USGS mapping study of groundwater salinity related to the distribution of 31 oil fields and adjacent aquifers "concluded that there is no hydrogeological connection between oil wells and water wells in the mapped regions." The primary basis for this conclusion was that "the top perforation of the oil wells is deeper than the bottom perforation of water wells, except for oil fields in the north eastern part of Kern County," which "showed little to no vertical separation."

The plan considered 264 permitted sites that could affect water quality, including sites for which WDRs have been issued under state law and confined animal sites. The locations of the permitted sites are shown on Figure 2-37 of the plan, which excludes 43 sites for which sufficient locational information was unavailable. Several of the permitted discharge sites include produced water ponds. The KGA GSP identifies and maps 77 open or active sites with the potential to adversely affect groundwater quality in the KCS. Several of these sites are associated with oil and gas exploration and development, including 27 produced water ponds in which crude oil is the primary constituent of concern. The plan states that underground injection control (UIC) "permitted wells are not included in the list of groundwater contaminant sites because the UIC program's objective is to confine injected fluid to the approved injection zone so that injected fluid does not migrate to a zone where it could degrade valuable groundwater or hydrocarbon resources." Figure 2-39 of the KGAGSP shows the locations of 127 wells injecting in non-oil zones with TDS concentrations that are below 3,000 milligrams per liter (mg/L) and 342 wells injecting in non-oil zones where TDS greater than 3,000 mg/L and less than 10,000 mg/L. The wells are mapped from a 2015 list provided to the U.S. Environmental Protection Agency (EPA) by the state in conjunction with the UIC aquifer exemption program under the Safe Drinking Water Act (SDWA). As discussed below, CalGEM and the EPA are continuing to implement a process for addressing permitted wells in California that may be discharging fluids into underground sources of drinking water (USDWs) as defined in the SDWA that have not been exempted under the UIC program. The California Appellate Court upheld the program in 2018. According to the most recent status report by CalGEM to the EPA, from 2017 to 2020 the EPA approved 20 aquifer exemptions, including several within the Project Area and certain of the locations identified in Figure 2-39 of the plan. Several other aquifer exemption proposals are being reviewed and considered by CalGEM, including locations in the Project Area (CalGEM 2020d).

Petroleum reservoir compaction due to oil and gas withdrawal is identified in the KGA GSP as a potential cause of land subsidence that would be identified in the datasets and local and remote-sensing subsidence monitoring system to be implemented under the plan. The plan states that "regional groundwater extraction is a main driver for regional-scale subsidence, along with subsurface geologic conditions." The plan provides for informing CalGEM in the event significant subsidence caused by oil and gas activities is detected in accordance with Public Resources Code Section 3315. Section 3315 requires that the state oil and gas supervisor (CalGEM) act as necessary "to arrest or ameliorate subsidence by maintaining or replenishing underground pressures in formations underlying" areas affected by oil and gas-related subsidence. The KGA GSP includes additional subsidence monitoring and detection requirements for certain critical infrastructure, such as at specific locations along the California Aqueduct, where extensometers or other monitoring may be required to determine the extent to which subsidence is caused by groundwater extraction or oil and gas activities in adjacent areas.

Several of the SGMA Projects listed in the KGA GSP involve additional development and use of produced water for domestic or irrigation purposes. KGA members that have proposed to use produced water to meet SGMA objectives for the KCS include that the AEWSD, the Cawelo Water Storage District, the EWMA. the North Kern Water District and the districts in the WDWA. These SGMA Projects are discussed in more detail in the following summaries of each of the 15 management area plans adopted within the KGA and included in the KGA GSP (KGA 2020).

Northeastern Management Areas in the KGA GSP

The EWMA plan, Cawelo GSA Management Area plan, and the KTWD Management Area plan overlie the Eastern Subarea and the Central Subarea in the northeastern portions of the Project.

EWMA Plan

The EWMA plan is the most easterly of the three northeastern management areas and encompasses approximately 35,000 noncontiguous acres. The planning area is distributed within approximately 113,500 non-districted acres. The plan states that oil production in the EWMA is "from aquifers that are not included within the basin" and produced from the Olcese Sand in the Poso Front field, the Kern River Formation and from the Jasmin, Freeman-Jewett, Pyramid Hills, Vedder, Chanac, and Walker Formations. The plan states that "all oilfields and exempted aquifers are not included within the basin" and that groundwater subject to an aquifer exemption under the UIC program "is external to the Kern Subbasin water supply, and does not fall under the regulatory purview of SGMA." The plan states that certain aquifer exemptions "are under review and subject to change in the near future."

Appendix B of the Stakeholder Communication and Engagement plan states that "the primary land uses in the EWMA are oil exploration and production and irrigated agriculture parcels. Groundwater pumped from private irrigation wells supplies most of the water needs for the agricultural parcels. The oil production portion of EWMA is a potential source of produced water that could be recycled for agricultural use." Section 16 of the EWMA plan identifies the "Evaluation of oilfield produced water supply (including options to better define available yield, aquifer extents horizontally and vertically, and the current fresh/saline water interfaces)" as one of the plan's "Water Supply Augmentation Projects" and SGMA "Potential Projects and Management Actions." Treated produced water from the Jasmin oil field in the northwestern portion of the EWMA is sold to the KTWD. According to the plan, "There are no known areas of groundwater contamination in the EWMA. Produced water ponds in the oilfields may have released untreated water to the shallow groundwater table in the past." The plan states that the Regional Water Quality Control Board (RWQCB) "is currently looking at historic ponds and requesting investigation where appropriate" (EKI Environment & Water 2019a).

Cawelo GSA Management Area Plan

The Cawelo GSA Management Area plan encompasses about 63,000 acres to the west of the EWMA and within the jurisdiction of the CWD. The plan states that the "Cawelo GSA overlaps three active oil fields: Kern Front, Kern River, and Poso Creek. With respect to defining the bottom of the groundwater basin, the shallow-most top of oil production in an oil field would provide a conservative estimate of the bottom of the Subbasin. In addition, the occurrence of petroleum hydrocarbons in the formation would inherently limit the use of formation water. This formation water is not connected to the groundwater system and not part of the groundwater basin pursuant to groundwater management. Most of the local oil fields have been exempted. . ."The plan states that "water supply wells in the Cawelo Water District are completed far above the oil producing zones." Treated produced water has historically been used for irrigation in the plan area and is summarized as follows:

> CWD purchases up to 36,000 AFY of treated produced water from local oil extraction operations . . . The treated produced water is pumped to CWD Reservoir B through a separate pipeline from the Kern River and Kern Front Oilfields. This water is treated to conform with the Central Valley Regional Water Quality Control Board's (CVRWQCB) waste discharge requirements and is blended with water from other sources before delivery to the CWD's water users where it is used for both irrigation and groundwater recharge in banking projects. Supplies from this source are dependent on local oil production, because the water is entrained in oil as it is produced. In recent years, the total delivery of treated produced water has ranged between 20,000 and 37,000 AF. The volume of treated produced water will fluctuate with oil production and long-term availability cannot be predicted. (Cawelo GSA 2019, 9–10)

Treated oil field water used by the CWD "is sampled monthly at Reservoir B for agricultural suitability" and the District provides water quality reports prepared by the treated oil field producers to the CVRWQCB to "illustrate compliance with regulations and guidelines" in applicable discharge permits. The plan states that "oil field operations in the Eastern Extension Area of the Cawelo GSA must comply with a regulatory framework that includes federal, state, and county level regulations. These regulations have direct and indirect implications for the Cawelo GSP and the sustainability of groundwater and groundwater quality, including groundwater monitoring plans and water management plans." Section 2.8 of the plan summarizes the regulations applicable to oil and gas activity in the Eastern Extension Area of the Cawelo GSA, including CalGEM oversight and regulations, the UIC program and aquifer exemptions, and groundwater monitoring by oil field operators "near oil and gas production activities that have potential to degrade waters suitable for beneficial use." Section 3.6 of the plan summarizes the oil field geology of the Kern Front, Kern River, and Poso Creek fields, including aquifer exemptions approved and pending under the UIC program and geologic and hydrological features that define the exempted formations. The plan states that "the bottom of the groundwater Subbasin beneath the Cawelo GSA will follow the base of the USDW as mapped by Gillespie et al . . . but will be modified by the top of oil fields and exempt aquifers where shallower than the base of the USDW. In addition, the Base of Fresh Water will also be modified by the top of oil fields and exempt aquifers where shallower that the elevation of fresh water as mapped by Page (1973)." Table 3-2 of the plan summarizes adjustments to the KCS bottom that have been made in the Cawelo GSA Area with respect to oil and gas activity using these criteria.

The Cawelo GSA Management Area plan indicates that "subsidence has been documented due to oil field operations at the Kern Front and Poso Creek oil fields on the order about 1 foot" and that "no evidence of subsidence has been documented at the Kern River Oil Field." Consistent with the KGA GSP, the management area plan includes subsidence monitoring. The plan states that "regional coordination of land subsidence monitoring is key to the design of the network in the Subbasin because regional groundwater extraction is a main driver for regional-scale subsidence, along with subsurface geologic conditions. In addition, subsidence associated with oil and gas activities may also occur in the subbasin. However, any subsidence potentially associated with oil and gas activities is regulated by [CalGEM] under the California Public Resources Code, and is therefore separate from SGMA requirements, thus, coordination may be needed where there is potential for impacts to critical infrastructure."

Table 4-1 of the plan states that a total of 481,880 AF of treated oil field produced water was imported into and used in the CWD from 1995 to 2014. A total of 86,863 AF was imported and beneficially used from 2015 to 2017. The plan discusses the future use of produced water over the applicable 2021 to 2070 SGMA planning and implementation period as follows:

> For the future scenarios, treated produced water deliveries were held constant for twenty years at 30,838 acre-feet per year which is 28 percent above the historical average rate and 75 percent above the average current rate of delivery. The future reliability of treated produced water is based on projections from local oil field operators. The projected reliability for future treated produced water for the Cawelo GSA is expected to be stable for the next twenty years. After twenty years, the delivery rates for treated produced water decrease by one percent every year from 2041 through 2070 to reflect the aging of the oil fields and reduction in oil and gas production. These deliveries are not impacted by changing climatic conditions. (Cawelo GSA 2019, 99)

Section 8 of the plan discusses projects that would be implemented to achieve SGMA requirements in the planning area. Potential projects to treat 7,000 to 20,000 AFY of produced water are identified as "Project #4" of the CWD's proposed SGMA Projects. The plan states that since the source of this water "is the byproduct of oil production . . . [i]t is reliable provided the oilfield is actively producing oil." The project includes a feasibility study to analyze "the lifespan of the oilfield and the potential for continued supply of treated produced water to the Cawelo GSA." The plan estimates that the approximate cost of treating produced water from local oil fields "to roughly freshwater quality is $600/AF to $900/AF, including capital and operational costs. The cost to treat 7,500 AFY to 20,000 AFY of OPW [oil field produced water] would range from about $4.5 million to $18.0 million per year." Potential funding for these expenses could include new assessments on a per-acre basis of from $100 to $400 per acre, which would require landowner voting approval under California Proposition 218 and possible federal or state grants. Produced water use is included as a supply source in Appendix G, Projected Future Water Budgets Baseline and Climate Change of the plan, which uses the same analysis methodology and scenarios as the KCS coordinated water budget for 2021 to 2070.

KTWD Management Area Plan

The KTWD Management Area plan includes 20,140 acres located on the eastern side of the San Joaquin Valley in Kern and Tulare Counties. The KTWD is located west of the EWMA plan in the Central and Eastern Subareas of the Project Area. The management area plan does not include significant references to oil and gas activities except as a source of imported water supplies. Section 2.2.5 of the plan states that the "district executed a 20-year contract with Hathaway, LLC in 2016 to receive produced water. The District currently receives about 2,400 acre-feet per year of water from this source on the east side of the District, which is delivered to the District's Big 4 reservoir to be blended with other water sources before being distributed. The source of oilfield produced water is from exempted aquifers beneath and hydrologically separated from the fresh-water bearing zones of the basin." Section 5 of the plan identifies SGMA "Projects and Management Actions" that would be implemented during the 50-year planning and implementation period. Action 2, the "CRC Pipeline Project - Produced Water Project" includes "obtaining an additional source of produced water from [the] California Resources Corporation (CRC). Produced water from CRC will be transported through 12 miles of 15-inch pipeline to the Guzman Reservoir. From the Guzman Reservoir, water will be transported through 1.8 miles of 30-inch pipeline to the District's existing Big 4 Reservoir, from which it will be blended with water from the Friant-Kern Canal and distributed in existing facilities to existing irrigated agriculture located within the District." The project is estimated to generate 3,000 AFY of "additional surface supplies" and reduce groundwater extraction by 1,440 AFY. The capital cost of the project is estimated to be $5.9 million. Appendix 3 of the plan includes 50-year water budget projections for the KTWD that assume the use of 2,400 to 4,900 AFY of produced water (KTWD 2019).

Southeastern Management Areas in the KGAGSP

The AEWSD Management Area plan and the TCWD Management Area plan overlie the southeastern part of the Project Area, including the southern portion of the Eastern Subarea and Central Subarea in the KCS south to the White Wolf fault.

AEWSD Management Area Plan

The AEWSD Management Area plan covers 105,630 acres in the southeastern portion of the KCS. The plan states that the presence, location, and depth of oil and gas fields and exempted aquifers are "sources of information can be relied on to define the 'bottom of the basin' for purposes of SGMA." The plan discusses oil and gas operations in the Edison and Mountain View oil fields and the approval of "aquifer exemptions for several deeper formations within the Edison Oil field" in 2018 and 2019 by the EPA. The plan states that "a large majority" of injection wells within the Edison and Mountain View oil fields are "located outside the Arvin-Edison Management Area boundaries in the northernmost portion of the Edison Oil Field. Produced water ponds are scattered throughout both oil fields, most of which are inactive. In total there are 35 active injection wells and 9 active produced water ponds within the Arvin-Edison Management Area boundaries." The plan discusses the state and federal regulations applicable to these activities. The plan states that "subsidence due to oil and gas production has also occurred in some areas but is secondary in importance" to "a documented history of subsidence, including historical and recent subsidence in the southern portion of the subbasin" that is "primarily due to withdrawal of groundwater."

Section 17 of the plan, List of Projects and Management Actions (SGMA Projects), identifies the "reclamation of oilfield produced water" as one of two "projects to develop new supplies." "Partnering agencies" required to implement the projects and management actions include "oil field producers." Table PMA 1 of the plan states that "reclaiming water from oil production facilities for irrigation purposes is currently an untapped water source in AEWSD. After treatment and cooling, produced water could be pumped into AEWSD facilities to serve irrigation demands in-lieu of groundwater pumping." The project would be implemented "upon agreement with oil field producers" could augment available supplies by 1,000 AFY. A feasibility study for the reclamation of oil field produced water project would be implemented during the first five years of the plan (EKI Environment & Water 2019b).

TCWD Management Area Plan

The TCWD Management Area plan covers 19,280 acres in the southeastern portion of the KCS in the southeastern corner of the Eastern Subarea of the Project Area. The plan states that although the depth of oil fields is used to define the SGMA basin boundaries in other locations of the KCS, "there are no oil fields underlying the TCWD MA [Management Area]" and "this consideration is not relevant to defining the bottom of the basin in the TCWD MA." As a result, the plan does not include a significant discussion of oil and gas activities (EKI Environment & Water 2019c).

Central Management Areas in the KGAGSP

KCWA – Pioneer Project Management Area plan, Kern Water Bank Authority Management Area plan, the NKWSD – SWID Management Area plan, the SWID 7th Standard Annex Management Area plan, the Southern San Joaquin Municipal Utility District Management Area plan, the SWSD GSA Management Area plan, and the Rosedale-Rio Bravo Management Area plan are primarily located in the central areas of the KCS and the Central Subarea of the Project Area, generally northwest of the City of Bakersfield.

KCWA– Pioneer Project Management Area Plan

KCWA– Pioneer Project Management Area plan was prepared by the Pioneer GSA for approximately 2,330 acres located to the southeast of the City of Bakersfield along the Kern River. SWP, CVP, and/or Kern River water is delivered from the Cross Valley Canal and the Kern River Channel to the Pioneer Project site for recharge. The plan states that the Canfield Ranch Oil Field is "in the Pioneer GSA Area." Based on salinity data derived in part from data obtained in the Canfield Ranch oil field, the plan indicates that "the base to fresh groundwater in the Pioneer GSA Area is approximately 1,000 feet." The plan states that "several factors may affect subsidence rates, including natural geologic processes, oil pumping and groundwater pumping" but that "these factors are not impacting the Pioneer GSA Area." The plan does not include additional significant discussion of oil and gas activities (Woodard & Curran 2019a).

Kern Water Bank Authority Management Area Plan

KWBA Management Area plan consists of 20,480 acres, by the KWBA southwest of the City of Bakersfield along the Kern River. KWB conserves surplus water by storing water in the Kern Fan aquifer and recovering previously stored water in dry years. The KWBA plan area is undeveloped except for water banking facilities, which include recharge basin berms, water control structures, canals, groundwater wells, and power lines. The plan states that "scattered third-party oil-field facilities are also present in some areas." The plan states that a zone of higher TDS occurs in the "shallow northeastern part of the aquifer that likely resulted from historic oilfield activities." The plan further states that "water in this zone has not been moving" and will eventually be removed by banking recovery operations. One KWBA monitoring well is identified as "impacted by the past disposal of produced water from oilfield operations." The plan does not include additional significant discussion of oil and gas activities (Parker 2019).

NKWSD – SWID Management Area Plan

The NKWSD – SWID Management Area plan was developed under a cooperative agreement between NKWSD, SWID, the City of Shafter, and the City of Wasco for the purposes of coordinating SGMA compliance and the development and implementation of a management area plan under the KGA. The NKWSD service area is approximately 60,000 acres, with an irrigated acreage of approximately 55,000 acres, and the approximately 10,000-acre Rosedale Ranch Improvement District. The service area for SWID is approximately 39,000 acres, with an irrigated acreage of approximately 30,000 acres. The plan area is located in the north-central portion of the Central Subarea of the Project Area. Incorporated cities within the NKWSD – SWID Management Area, including the City of Shafter and the City of Wasco, are not within the County's jurisdiction.

The plan states that "the lateral and bottom boundaries of the groundwater in the Subbasin are constrained by the primacy productive limits with depths to hydrocarbons, and aquifer exemptions with corresponding depths. However, within NKWSD, north of 7th Standard Road and SWID, there are no aquifer exemptions, and the oil field depths to hydrocarbons are below the base of 10,000 ppm TDS. South of 7th Standard Road, the Rosedale Ranch Oil Field underlies agricultural lands that may have groundwater production. The base of 10,000 ppm TDS may underlie the depth to hydrocarbons of the oil field; where applicable, the shallowest of the two is considered the bottom of the Subbasin."

The plan states that several processes contribute to land subsidence in the KCS and include, "in order of decreasing magnitude: aquifer compaction by overdraft, hydro compaction (shallow or near- surface subsidence) of moisture deficient deposits above the water table that are wetted for the first time since deposition, petroleum reservoir compaction due to oil and gas withdrawal, and subsidence caused by tectonic forces."

In 2015, NKWSD entered into an agreement with the California Resources Corporation for the delivery of 11,700 AFY to 21,200 AFY oil field-produced water from the Kern Front oil field. The plan indicates that this agreement extends through 2035 and currently requires delivery of 11,700 AFY through 2025. The produced water is blended with other supplies and used directly for irrigation or for groundwater recharge. Table 5-1, Proposed list of Projects and Management

Actions for North Kern Water Storage District of the NKWSD – SWID Management Area plan, " identifies "beneficial reuse of oilfield produced water" as one of the district's SGMA Projects. The expected "water supply augmentation" from this project is 11,000 AFY, with an "ongoing cost" of $1 million per year. Table 5-1 also includes an SGMA Project that would allocate "oilfield produced water from NKWSD to Rosedale Spreading Basin for Rosedale Ranch Improvement District benefit." The amount of water supply augmentation and ongoing annual costs of this SGMA Project are not identified (GEI Consultants, Inc. 2019a).

SWID 7th Standard Annex Management Area

The SWID 7th Standard Annex Management Area plan covers the 7th Standard Annex Management Area, approximately 10,000 acres that were annexed into the SWID in 2019. The plan area is located south and west of the City of Shafter and in the Central Subarea of the Project Area. The plan states that "taken together, the available data sources reflect a similar range of depths for the bottom of the basin, generally consistent with the bottom of basin as identified in the KGA Umbrella GSP, with the basin bottom being significantly deeper in the eastern portion of the Management Area than it is in the western portion." An oil field is located in the western portion of the Management Area. The plan identifies one former produced water pond as one of two "open" potential groundwater contamination sites near the Management Area. The plan states that "based on data available on Geotracker and Envirostor, there does not appear to be any identified groundwater contamination resulting from the two active sites. Given that most of these sites have received regulatory closure and that groundwater is generally hundreds of feet below the surface and separated from near-surface contamination by numerous thin low permeability layers, the threat to groundwater from these identified sites is likely minor" (EKI Environment & Water 2019d).

Southern San Joaquin Municipal Utility District Management Area Plan

The Southern San Joaquin Municipal Utility District Management Area plan is approximately 66,000 acres, with an irrigated acreage of approximately 51,000 acres. The plan area is located at the northern end of the Central Subarea in the Project Area. The plan states that while the lateral and bottom boundaries of groundwater in the KCS "are constrained by the primacy productive limits with depths to hydrocarbons, and aquifer exemptions with corresponding depths." However, the plan also states that "there are no aquifer exemptions or active oil fields within the District." As a result, the plan does not include a significant discussion of oil and gas activities (GEI Consultants, Inc. 2019b).

SWSD GSA Management Area Plan

The (SWSD) GSA Management Area plan includes approximately 222,600 acres, with approximately 144,100 acres of irrigated lands (including 6,400 acres of managed wetlands), 8,960 acres associated with the Kern National Wildlife Refuge, and 69,500 acres of primarily undeveloped native vegetation. The plan area accounts for the majority of land within the northern half of the Central Subarea of the Project Area. The plan states that while the lateral and bottom boundaries of groundwater KCS "are constrained by the primacy productive limits with depths to hydrocarbons, and aquifer exemptions with corresponding depths . . . there are no aquifer exemptions or active oil fields within the District." The plan also indicates that "underlying oil field operations" were considered as a possible cause of subsidence, but that "within the SWSD study area, no long-term signatures were identified that could be related to nearby oil and gas operations" (GEI Consultants, Inc. 2019c).

Rosedale-Rio Bravo Management Area Plan

The Rosedale-Rio Bravo Management Area (RRBMA) plan encompasses approximately 48,610 acres of lands (76 square miles) located west of Bakersfield between Stockdale Highway to the south and 7th Standard Road to the north. The plan area is primarily located in the Central Subarea and also extends beyond the eastern border of the Western Subarea of the Project Area. The plan states that "[s]cattered oil-field facilities [are] present in some areas." and that "[h]igh TDS concentrations (700-1300 mg/l) were found in the vicinity of the Rio Bravo and Greeley Oil Fields." The plan lists "oil well re-pressurization" as one of the known beneficial uses of groundwater use in the Management Area "for industrial activities that do not depend primarily on water quality." The amount of this use is not quantified. Appendix A-1 of the plan is the Rosedale-Rio Bravo Water Storage District Banking and Sale Memorandum of Understanding. The Memorandum of Understanding provides that the project's "Monitoring Committee shall be notified prior to the recharge of potentially unacceptable water, such as 'produced water' from oilfield operations" (KGA 2019).

Western Management Areas in the KGAGSP

The WKWD Management Area plan, the WDWA Management Area plan, and the WRMWSD Management Area plan are primarily located in the west of the KGA GSP and in the Western Subarea of the Project Area. Portions of the WRMWSD Management Area plan also extend into the Central and Eastern Subareas in the south of the Project Area, and the WDWA Management Area plan extends into the Central Subarea in the north.

West Kern Water District Management Area Plan

The WKWD Management Area plan covers approximately 183,680 acres (287 square miles) and includes the cities of Taft and Maricopa. The WKWD GSA is located in the southern half of the Western Subarea of the Project Area and includes the WKWD boundary and adjacent oil field properties owned by corporate and independent operators that have requested coverage under the WKWD GSA, as well as state land and privately owned parcels. Taft, Maricopa, and other incorporated communities and state-owned lands in the WKWD Management Area are not within the County's jurisdiction.

The plan defines the lateral and vertical boundaries of the SGMA groundwater basin using substantially the same criteria described in the KGA GSP. The plan states that "active oil and gas aquifers and exempted aquifers are not a part" of the KCS "groundwater basin for beneficial use." The "lateral and vertical boundaries" of the KCS are defined as the shallowest of "depth to producible minerals or hydrocarbons, depth to and aerial extent of exempted aquifers [and] the depth at which groundwater cannot now or in the future serve as a source of drinking water." To illustrate these boundaries, the plan states that "water bearing zones below the depth to producible hydrocarbons are not within the groundwater basin; likewise, water bearing zones below an exempted aquifer are not within the groundwater basin. In some parts of the Subbasin the lateral and bottom boundaries of the groundwater are subject to depths to producible hydrocarbons and extent of depths to aquifer exemptions."

The plan states that the WKWD GSA "overlies a petroleum producing area. Impacts to WKWD's groundwater supply by these operations, both actual and potential, are continuously monitored and evaluated. WKWD takes a proactive approach in addressing and correcting any contamination threats to its groundwater supply. To date, no significant threat to groundwater quality has occurred because of local oil and gas operations. No further actions to address oil and gas production are required in this . . . GSP." The plan states that "produced water in western Kern County is typically managed by either recycling it for enhanced oil recovery (EOR) operations, such as steam/cyclic steam flooding, or by permitted disposal under the regulatory oversight" of CalGEM. During EOR operations, "a portion of the water that is reused . . . is inevitably lost to the geologic formation or to the process of steam generation." Because of this loss, "make up water" is purchased from WKWD. According to the plan, "a significant percentage of the oil field produced water in the WKWD GSA's western management area is either recycled into the same geologic zones it was produced from, or is sequestered in deeper zones that are isolated from sources of drinking water. This water is supplemented by water purchased from WKWD, which indicates that very little water is disposed of, since purchasing fresh water is more expensive than recycling water." The plan estimates that "Roughly 80 percent of WKWD's water supply is delivered to industrial companies, primarily for oil development and power plants." The plan states that WKWD "has operated its groundwater banking efforts with a net positive volume of stored water for recovery during times of supply shortages, such as drought" and that the district "expects that demand for groundwater will decrease as the oilfields in its jurisdiction reduce pumping (and therefore, related associated water demands)."

The plan references the same list of potential water quality impact sites in Figure 2-26 of the KGA GSP, which include produced water ponds. The plan states that "[t]hese sites are in the far western portion of the Western Management Area and cannot affect water management activities in other WKWD GSA management areas." The plan states that "[s]everal processes contribute to land subsidence in the subbasin and include, in order of decreasing magnitude: aquifer compaction by overdraft, hydrocompaction (shallow or near-surface subsidence) of moisture deficient deposits above the water table that are wetted for the first time since deposition, petroleum reservoir compaction due to oil and gas withdrawal, and subsidence caused by tectonic forces." While produced water is "properly excluded from the Water Budget, DWR's Water Budget BMP directs the GSA to consider whether such produced water will cause undesirable results. Subsidence can be caused by a variety of factors and will be appropriately monitored throughout the basin." According to the plan, "oilfield produced water is produced from sediments and formations that are below the bottom of the [SGMA-regulated] basin." The plan states that "because the regulation of oil produced water under SGMA is not fully clear at this time" the "evaluation of oil produced water" will be reevaluated during the first five-year plan update. The WKWD GSA will "coordinate with oil producers to identify approaches to enhance water quality monitoring and reporting of oil produced water to ensure that groundwater quality is protected" (Woodard & Curran 2019b).

WDWA Management Area Plan

The WDWA Management Area plan is located in the northern part of the Western Subarea of the Project Area. Portions of the plan area extend into the northwest portion of the Central Subarea. The plan includes approximately 227,193 acres in the Lost Hills Water District (LHWD), the Berrenda Mesa Water District, and the Belridge Water Storage District (BWSD). The plan indicates that these districts primarily provide SWP surface water for agricultural irrigation. In the LHWD, the plan states that a “small portion of the LHWD surface water supply is sometimes delivered as industrial water to agricultural processors and oil field production customers.” In the BWSD, the plan states that “[i]n addition to agriculture, a percentage of the annual allocation from the SWP is delivered for industrial use in oil recovery operations in the North and South Belridge oil fields.” None of the districts provide municipal water supplies.

About 113,682 acres of undistricted land are also located within the WDWA and “consist of a mixture of uses, including, among other things, mountain-front slopes, non-irrigated lands, grazing land, oil field production, quarry operations, and limited agriculture.” The plan indicates that in these areas “[o]il field activities may utilize some groundwater from water wells for field activities (e.g. well drilling, enhanced oil recovery “make-up water” etc.). Oil fields also generate produced water as part of oil extraction activities. Produced water contains residual oil, elevated TDS derived from geologic formations, and other constituents common to crude oil production. A majority of produced water from oil field operations is either reinjected into the same zone it was extracted from for enhanced oil recovery (EOR), or is sequestered in deeper exempt aquifers . . .” The plan states that “[t]he potential for impacts to the occurrence or quality of groundwater posed by oil field operations, and those undistricted lands that are not part of the WDWA . . . are beyond the control of the WDWA.” Due to generally poor groundwater quality within the WDWA plan area, total groundwater use is considered to be limited and estimated in the plan to be approximately 3,000 AFY.

The plan states that the “bottom of the Subbasin varies vertically and laterally with: Depth to commercially producible minerals or hydrocarbons; Depth to exempted aquifers; The depth that makes recovery of water for drinking water purposes no longer economically or technologically feasible; and The depth at which groundwater cannot now, or in the future, serve as a source of drinking water.” The plan indicates that the vertical and lateral basin boundary “may be described as the combination of the itemized list below (i.e., item A, and either item B or C). . . .A. Depth to commercially producible minerals or hydrocarbons (40 CFR §146.4) (where it applies to discrete areas of the Subbasin), or the depth to an exempted aquifer; and either: B. Depth to water at a TDS that is no longer economically or technologically feasible for groundwater beneficial use; or C. Depth to waters of TDS greater than 10,000 mg/L” and “not suitable as an Underground Source of Drinking Water (USDW).” The plan states the following:

> In the WDWA, oil is produced from geologic structures that are comprised of some of the same formations that produce brackish groundwater elsewhere in the WDWA. The Tulare and Etchegoin Formations are two examples of this condition. In addition to containing hydrocarbons, many of these oil-bearing zones also contain naturally degraded formation water (i.e. produced water). Based on the presence of hydrocarbons in these structures,

> many of the associated formations are also designated as exempt aquifers . . . within the administrative limits of the individual oil field. Examples of oil fields with aquifer exemptions include, among many others, the Lost Hills Oil Field and the Belridge Oil Field complex. Both oil field produced water and WDWA groundwater are naturally degraded by elevated concentrations of TDS and other constituents. With few exceptions, these conditions are found throughout the WDWA. (WDWA, ES-13)

Section 2.7.5 of the plan discusses “Oil Field Produced Water” and states that “there are currently 16 oil and gas fields or portions thereof in the WDWA.” The plan states the following:

> Oil field produced water in western Kern County typically contains entrained oil, elevated TDS, and other constituents. Because of this, oil field produced water is unsuitable for any beneficial use without extensive treatment. Produced water is managed by either recycling it for enhanced oil recovery (EOR) operations, such as steam/cyclic steam flooding or water flooding, or by exempted disposal in deeper zones. Both of these activities are under the regulatory oversight of [CalGEM] and the US EPA. Produced water used for steam or water flood EOR is typically reinjected under permit into the same geologic zone from which it was produced (e.g., Tulare or Etchegoin Formations) to help maintain oil reservoir pressures and sweep residual oil towards planned oil extraction wells. During this process, a portion of the water that is recycled is inevitably lost to the geologic formations within the field or to the process of steam generation, etc. In addition, so called ‘make up water’ from freshwater sources like the Aqueduct, may be added to the process depending on field conditions. Reinjection of produced water back into the zone from which it was extracted potentially helps to mitigate the rate of local land subsidence. It is important to clarify that the type of EOR discussed here is not hydraulic fracturing. Disposal of brackish and saline oil field produced water in Western Kern County has typically employed two methods: (1) evaporation ponds; or (2) reinjection into exempt aquifers identified for this purpose pursuant to regulations of the Federal UIC Program . . . . Due to water quality concerns, many of the produced water disposal ponds in Kern County have been closed. Consequently, reinjection into exempt aquifers has become the primary method of produced water disposal. Aquifers identified for permitted disposal reinjection are by design isolated from nonexempt underground sources of drinking water. As with the EOR methods described above, disposal-well reinjection does not involve, nor is it in this case related to, hydraulic fracturing . . .. In summary, a significant percentage of the oil field produced water in the WDWA is either recycled into the same geologic zones it was produced from for the purpose of EOR or is sequestered in deeper zones that are isolated from underground sources of drinking water. Like groundwater in the WDWA in general, produced oil field water is naturally degraded and exhibits elevated levels of TDS. The concentrations of TDS and crude oil residual in untreated produced water make it unsuitable for any beneficial use without treatment. (Aquilogic 2019, 64–65)

The plan states that the “occurrence of high TDS groundwater in the west side of the KCS has recently been further documented in a [2018] preliminary groundwater salinity mapping study conducted by the USGS . . . of groundwater salinity for 31 oil fields and adjacent aquifers across major oil-producing areas of central and southern California." Within the KCS, the plan states that the study "reported much higher TDS in groundwater from Westside oil field wells and groundwater wells, when compared with east side groundwater wells and oil wells." The study suggested that among other factors, "higher TDS in the Westside could be related to a combination of natural conditions (Westside sediments derived from marine deposits containing saline connate water) and anthropogenic factors such as infiltration from former oil field produced water evaporation ponds and/or agricultural drainage ponds. This higher TDS water is consistent with historical reports completed prior to widespread agricultural development and is documented for more than 60 miles from north to south in the west side of the KCS." The plan states that available water quality "data reiterate the conclusion that, with few exceptions, a majority of the groundwater, including oil field produced water beneath the WDWA on a sub-regional basis is brackish, and of little, if any, beneficial use without blending or treatment."

The plan discusses produced water disposal ponds in the LHWD area. Regarding groundwater, it states the following:

> [Groundwater] is very brackish and has been impacted, likely both by the nearby ponds and the naturally poor quality of groundwater found throughout the WDWA. As such, this groundwater would be unsuitable for any beneficial use without expensive advanced water treatment technology capable of desalination such as reverse osmosis (RO) or other membrane technology. Because of the location of the ponds on the eastern boundary of the LHWD there is also the likelihood that brackish, poor quality groundwater, has migrated down-gradient towards the adjacent SWSD. If confirmed, coordinated monitoring and management of the brackish water will be required during the implementation of the KGAGSP to mitigate the potential for further undesirable results to better quality water to the east of the WDWA. (Aquilogic 2019)

Produced water ponds and groundwater are also discussed in the BWSD area. The plan discussed regulated water quality events and, where applicable, enforcement orders associated with three oil and gas-related sites, including "Aera Energy's former South Belridge Oil Field Ponds; Exxon/Mobil Hill Lease; and Valley Water Management Ponds." The plan states the following:

> The data support the conclusion that the groundwater quality beneath the BWSD is largely naturally degraded and is sometimes impacted by localized anthropogenic activity (e.g., evaporation ponds). That said; the groundwater beneath the WDWA is almost exclusively unsuitable for MUN [municipal] and most, if not all, AGR [agricultural] or other beneficial use without blending and/or desalination. There is also the potential for these primarily naturally degraded groundwaters to migrate outside the WDWA where it would produce or perpetuate an undesirable result in adjacent GMAs [groundwater management areas]. To mitigate any undesirable result related to poor water quality originating from the WDWA, the WDWA will work in close cooperation with oil producers and down-gradient, adjacent GMAs during the implementation of the KGAGSP to conduct sentry monitoring as part of the WDWA MNP [monitoring network plan] in order to assess for changes in groundwater quality on its boundaries. (Aquilogic 2019)

Figure 23b of the plan identifies approximately 44 Permitted Discharge Locations in the WDWA, "a majority of which appear to be related to oil field produced water treatment facilities." Appendix F of the plan lists the same 77 sites included in the KGA GSP as open and having potential or confirmed groundwater quality impacts.

The plan states that "oil field activities, including land subsidence associated with the extraction of oil and gas, are under the oversight of [CalGEM], and are therefore outside the control of the WDWA. This element will be assessed further as part of the WDWA MNP and the KGA land subsidence monitoring plan. Data and findings will be reported during the first five-year reassessment period." The plan discusses two localized areas of land subsidence identified in the WDWA by satellite-based Interferometer Synthetic Aperture Radar (InSAR) surveys. It states the following:

> [One is located] just west of the portion of the [California] Aqueduct that lies immediately north and south of the town of Lost Hills (approximately Aqueduct mile post 195-203 and milepost 205-215). Subsidence here is estimated to range between 4 inches to 15 inches. This portion of the Aqueduct coincides with an embankment failure in June 2011 at Milepost 208. This incident was confirmed by surveying, but a specific cause was not identified at the time of the breach. It is important to emphasize that agricultural groundwater pumping in this area has historically been limited due to poor groundwater quality. The other area of subsidence is located approximately midway between town of McKittrick and State Highway 46 and is likely associated with the Belridge Anticline oil field complex. InSAR subsidence there has reportedly ranged from 4 inches to over 25 inches. (Aquilogic 2019)

According to the plan, InSAR data during 2015 and 2016 found the following:

> improved conditions, with the areas adjacent to the town of Lost Hills (e.g. Mileposts 195-215) mostly displaying only minimal subsidence (approximately 2 inches to 6 inches). The areas around the Belridge Anticline oil field also improved somewhat, with the exception of areas immediately proximal to the oil fields, which appear to have remained more or less unchanged from the findings of the earlier InSAR survey. The rebound of topographic surface elevation indicated by the latter InSAR survey in several areas suggests that some of the WDWA subsidence may have a reversible (elastic) component that benefited from the increased winter precipitation during 2015 to 2016. (Aquilogic 2019)

The plan indicates that there is "currently is no definitive evidence that the subsidence adjacent to the aqueduct near Lost Hills . . . or elsewhere in the WDWA, is attributable to a single factor." The plan states that "subsidence associated with local oil field activities is under the oversight of [CalGEM]. Subsidence in the WDWA caused by oil field activities and by pumping in adjacent GMAs is outside the control of the WDWA."

No municipal pumping of groundwater occurs in the WDWA. The plan states that "because of the ubiquitous presence of elevated concentrations of TDS, the use for [agriculture] is primarily limited to blending with higher-quality Aqueduct water when those deliveries are reduced. Industrial use is mainly limited to oil field operations, such as water for well drilling or enhanced oil recovery (EOR) via steam generation and reinjection."

The plan identifies SGMA Projects. PMA No. 3 is the "Conjunctive Reuse of Naturally Degraded Brackish Groundwater." It focuses on the following:

> feasibility of an innovative project that will integrate the treatment and conjunctive reuse of naturally degraded brackish groundwater and oil field produced water. Based on preliminary planning the project will ultimately harvest and treat approximately 40% oil field produced water and 60% brackish groundwater underflow for multiple beneficial uses including, among other things: A potential new water supply for adjacent and nearby disadvantaged communities (DACs) in order to improve water reliability and drought resiliency; A reliable supplemental source of better-quality water that, together with imported water, can be used for irrigation; Provide potential environmental flows to the adjacent Kern National Wildlife Refuge; and Protect groundwater quality adjacent to the WDWA by reducing the volume of naturally degraded groundwater underflow migrating to the northeast and east from the WDWA toward potentially better-quality groundwater in the axis of the Valley and adjacent management areas. (Aquilogic 2019)

The plan further discusses PMA No. 3 as follows:

> Sub-regionally, most of the groundwater in the WDWA is of poor to very poor quality, with TDS concentrations routinely greater than 2,000 mg/L, making it unsuitable for practical beneficial use within the WDWA without blending or treatment. The poor water quality is caused by geologic sediments of marine origin, some of which contain saline connate water. The principal source of modeled deficit in the WDWA is due to natural downgradient underflow out of the WDWA towards the northeast (former Tulare Lake bed, a designated beneficial use exemption area), and eastward towards the axis of the basin. Historically, WDWA growers have, among other water management techniques, used Aqueduct water (significantly more than 95%) to meet their water supply demand. Groundwater withdrawals have been minimal (~3,000 AFY), and have been used largely for the purpose of blending. However, climate variability has placed stress on the reliability of imported water. During the recent extended drought period (2007 to 2016), actual deliveries from the SWP to the WDWA averaged less than 50% of the stipulated allocation. The proposed drought resiliency infrastructure project (Project), when fully implemented, would provide for treatment and conjunctive reuse of a mixture of oil field produced water, and naturally degraded groundwater that is currently escaping the WDWA as underflow. Membrane technologies and associated system control software to treat brackish and saline water are well established and the cost of treatment is declining. Many of these proven technologies are now 'off the shelf' and modular, allowing for cost-effective facility upscaling as part of planned project phasing, or as operational conditions change. The Project proposes to utilize a modular treatment system in order to right-size the project and maximize and maintain the balance between project economics and desired benefits. As envisioned, the PMA No. 3 would include at least two similar construction

phases over the next 10-20 years, each with an array of brackish groundwater underflow-capture wells located along the eastern or northern boundaries of the WDWA. These wells along with some oilfield produced water would eventually provide the source water for two or more distributed modular treatment systems. When fully operational, the Project, as currently planned, could produce up to 50,000 AFY of new, high-quality water for multi-beneficial reuse options. Potential sources of feed water for the project include degraded brackish groundwater underflow from the WDWA and surplus oil field produced water. Current groundwater underflow that migrates from the WDWA, downgradient towards the axis of the basin, has been preliminarily estimated by the KGA C2VSim-Kern model at approximately 111,000 AFY. Because of the brackish quality of this water, it is considered to be non-beneficial without treatment or blending. The oil fields of West Kern County generate approximately 10 to 12 barrels of brackish or saline produced water for every barrel of oil. A large portion of the produced water is recycled and used at the oil fields for steam flooding for EOR, and other oil field operations. However, any remaining surplus volume of produced water requires disposal. Due to water quality concerns, many of the produced water disposal ponds in Kern County have been closed. This leaves permitted reinjection into typically deeper zones under the oversight of [CalGEM] and the Federal UIC program as the primary method for disposal of produced waters. The Project would, if determined to be feasible, divert a portion of this surplus produced water for additional treatment and conjunctive reuse. Preliminary planning for a Project Engineering feasibility study (FS) for the first phase of the project has already begun. It is expected there will be at a minimum two phases of distributed treatment facility construction. The FS will examine the viability of the project for regulatory acceptance, potential for undesirable results (e.g. significant subsidence), and for the economics of treating both brackish groundwater and oil field produced waters in a distributed modular facility via the use of readily available membrane technologies, such as reverse osmosis (RO). Treatment technologies to be assessed would include pre-treatment, pH adjustment and filtration followed by either a single-pass RO configuration, a double-pass RO, or a RO modification called a closed-circuit RO. Treated water quality would, at a minimum, meet Basin Plan requirements. Project FS components include: Evaluating existing hydrogeologic data pertaining to brackish groundwater and oil field produced water quality, water use, and volumes; Development of preliminary engineering options and costs for siting the treatment facility, source wells, water treatment, energy demand, concentrate disposal, and treated water transmission; Examination of the potential for undesirable results (e.g. subsidence); and Assessment of permitting and public notification requirements (California Environmental Quality Act [CEQA], etc.) . . .. The FS will include information on the study area, as well as water supply, source water, and RO concentrate characteristics and treatment facilities. A project alternative analysis will be performed leading to a recommended plan for implementation including a preliminary construction schedule and financing plan, a revenue program, and a net present worth analysis. Findings and status of the FS implementation would be reported in the first five-year GSP reassessment. It is a goal to have the first modular treatment system online before the end of the second five-year reassessment period (by 2030). Public noticing for this project would be implemented pursuant to relevant and applicable

> rules and regulations and would be distributed via the websites of the stakeholder water districts and other methods, as required. Permitting (CEQA, construction, etc.) will also comply with relevant and applicable rules and regulations. Key issues to be addressed during the FS include those related to technical feasibility, project phasing, regulatory and public acceptance, potential project-related undesirable results, the development of an engineering cost/benefit analysis, State or other funding alternatives and permitting (e.g. CEQA, etc.). The FS will seek to identify the preferred project alternative by examining the CEQA required "no project alternative" in addition to several different construction and RO configurations, combined with varying approaches for concentrate (brine) disposal. End-users of the new water supply will be identified, including local DACs, agricultural, oil field, and environmental users. Ultimately, this project directly supports WDWA water resources and provides the benefit of a new water supply to the State. Specific benefits include: Ability to wheel water of acceptable quality to neighboring management areas that may be facing shortage; Increased regional and local water self-reliance, flexibility and integrated management; Drought resiliency; Ability to decrease agricultural reliance on diversions from the Delta via the Aqueduct; and Increase operational and regulatory efficiency for improved drought resiliency." (Aquilogic 2020, 94–98)

According to the plan "rough order-of-magnitude costs for the initial phase of the project range from $50 million to $60 million +/- 20% depending on site location and number of capture wells to be installed. Refined costs will be generated by the . . . FS. Project costs and funding are among key feasibility factors. Funding sources could include a combination of State, WDWA and other stakeholder or private funding."

WRMWSD Management Area Plan

The WRMWSD Management Area plan encompasses 91,430 acres, primarily in the southern portion of the Western Subarea and extending into the southern parts of the Central and Eastern Subareas of the Project Area. The plan states that "the presence, location and depth of oil and gas fields" is one of the "multiple sources of information can be relied on to define the 'bottom of the basin' for purposes of" the SGMA. Oil fields in the plan area include the San Emidio Nose oil field, located in the central portion of the Management Area, the Yowlumne oil field, located in the western portion of the Management Area, the Los Lobos oil field, which overlies a small portion of the southwestern corner of the Management Area, and the Midway-Sunset oil field, which overlies portions of the far western edge of the Management Area.

The plan identifies potential point sources of groundwater contamination in the Management Area, one of which is a closed site associated with oil and gas development and exploration. The plan states that "[g]iven the lack of open sites and the fact that groundwater is generally hundreds of feet below the surface and separated from near-surface contamination by numerous thin low permeability layers, the threat to groundwater from the closed sites is likely minor." According to the plan "[w]ithin the Management Area there are 12 active injection wells, all but one of which are in the Yowlumne oil field (the other being in the Rio Viejo oil field). There are also a large number of injection wells in the Midway-Sunset oil field to the west of the Management Area.

There are no produced water ponds within the Management Area, but there are many in the Midway-Sunset oil field." The plan states that the injection wells are regulated under the UIC program and other laws and regulations, and produced water ponds are regulated by the state under "individual and general Waste Discharge Requirements (WDRs) amongst other requirements to ensure adequate protection against impacts to underlying groundwater resources." The plan states that "[s]ubsidence due to oil and gas production has also occurred in some areas but is minor in importance" (EKI Environment & Water 2019e).

Kern River GSP

The KRGSP is located in the central portions of the Project Area and encompasses 184,320 acres (361 square miles), including the Bakersfield Metropolitan area, highly developed agricultural areas, riparian ecosystems, and open space, including private lands held in public trust, such as the Panorama Vista Preserve, and municipal parks, such as the Kern River Parkway. Incorporated communities within the KRGSP are not within the County's jurisdiction.

The KRGSP states the following:

> [The plan] overlies all or portions of about 23 active or abandoned oil fields. The presence of petroleum hydrocarbon reservoirs indicates that the geologic formation is isolated at depth without the ability to be readily replenished by groundwater recharge (a condition required to trap the hydrocarbons). In addition, the occurrence of petroleum hydrocarbons in the formation would inherently limit the use of formation water. Although water produced from some Kern County oil fields is being separated and treated for beneficial uses in other areas, this formation water would not be connected to the groundwater system and not be considered part of the groundwater basin pursuant to groundwater management. In addition, most of the local oil fields have been exempted from the USEPA definition of protected groundwater . . . Therefore, the shallow-most top of oil production in an oil field would provide a conservative estimate of the bottom of the Subbasin, where present. (KRGSA 2020)

Most of the oil fields beneath plan area "are located along the margins of the boundary with only a small portion of their productive limits in the KRGSA. . .The bottom of the Subbasin beneath the KRGSA plan area is defined as groundwater outside of a hydrocarbon zone that contains no more than 10,000 mg/L TDS unless that water has been determined to be an exempt aquifer . . . It is further assumed that the Subbasin would be a continuous unit from the surface down to the basin bottom; no formations below the shallowest oil producing zone or shallowest exempt aquifer would be included." The plan states that "[b]ecause the oil bearing zones are defined as beneath the bottom of the Subbasin, there would be no decrease of groundwater in storage associated with water in the oil bearing zones. The Subbasin extends several thousand feet beneath the plan area with the bottom defined by either the base of the Underground Source of Drinking Water (USDW, defined by USEPA), oilfield-exempted aquifers, or oil-producing zones, whichever is shallowest."

Table 3-4 of the plan identifies "Environmental Investigation and Cleanup Sites in the Plan Area." The plan states that "about one-half of the sites involve petroleum hydrocarbons including crude oil, gasoline, and associated products . . . mainly related to refineries, oil companies, transportation sites, schools (with fuel tanks), as well as the three LUST [large underground storage tank] sites" (KRGSA 2020).

Henry Miller Water District GSA GSP

The Henry Miller Water District (HMWD) GSA GSP is located in the south of the Western Subarea of the Project Area and includes 26,055 acres. The plan area primarily consists of irrigated agricultural land, but also includes an artificial recreational lake, undeveloped land, the California Aqueduct, and land used for oil and gas production.

The plan defines the lateral and vertical boundaries of the plan area basin using substantially the same criteria as the KGA GSP. The plan states that "active oil and gas aquifers and exempted aquifers are not a part of the groundwater basin for beneficial use." The plan states the following:

> Water brought to the surface when oil is extracted is often referred to as 'produced water.' Produced water is groundwater that is commingled with hydrocarbons and located within the hydrocarbon bearing reservoir. Produced water is generated as oil is extracted for use. Often, produced water is returned to the original geological formation for enhanced oil recovery or disposal. Some produced water is suitable for beneficial use with treatment, though most is higher in salinity and must undergo extensive treatment and be blended with other water before use. New technology and the need to find new sources of water are driving the ability to process and treat produced water for beneficial use. (Luhdorff & Scalmanini 2020)

The plan discusses a 2018 USGS study of 31 oil fields and adjacent aquifers in California and states that "the study concluded that there is no hydrogeological connection between oil wells and water wells in the mapped regions. This conclusion is based on salinity mapping and well construction: the top perforation of the oil wells is deeper than the bottom perforation of water wells, except for oil fields in the north eastern part of the County. Well perforations in the north eastern part showed little to no vertical separation. Additionally, the study found that the west side of the San Joaquin Valley (in Kern County) generally has the highest TDS levels at the shallowest depths." The plan also includes a discussion of oil and gas subsidence that is substantially similar to the KGA GSP subsidence discussion and indicates that if oil and gas subsidence is detected by SGMA-related monitoring CalGEM would be notified in accordance with Public Resources Code Section 3315.

Figure 2-39 of the HMWD GSP is substantially the same as Figure 2-39 in the KGAGSP and shows the locations of 127 wells injecting in non-oil zones with TDS concentrations that are below 3,000 mg/L and 342 wells injecting in non-oil zones where TDS greater than 3,000 mg/L and less than 10,000 mg/L. The wells are mapped from a 2015 list provided to the EPA by the state in conjunction with the UIC program. According to the most recent status report by CalGEM to the EPA, during 2017 to 2020 the EPA approved 20 aquifer exemptions, including several within the Project Area and certain of the locations identified in Figure 2-39. Several other aquifer exemption proposals are being reviewed and considered by CalGEM, including locations in the Project Area (CalGEM 2020d).

The plan considered the same 264 permitted sites that could affect water quality as discussed in the KGA GSP, including sites for which WDRs have been issued under state law and Confined Animal Sites. The locations of the permitted sites are shown on Figure 2-37 of the plan, excluding 43 sites for which sufficient locational information was unavailable. Several of the permitted discharge sites include produced water ponds. The plan also identifies and maps 77 open or active sites with the potential to adversely affect groundwater quality in the KCS. Several of these sites are associated with oil and gas exploration and development, including 27 produced water ponds in which "crude oil" is the primary constituent of concern. The plan states that "UIC permitted wells are not included in the list of groundwater contaminant sites because the UIC program's objective is to confine injected fluid to the approved injection zone so that injected fluid does not migrate to a zone where it could degrade valuable groundwater or hydrocarbon resources" (Luhdorff & Scalmanini 2020).

Olcese Water District GSA GSP

The Olcese Water District GSA GSP covers approximately 3,206 acres in the eastern portion of the KCS and in the Eastern Subarea of the Project Area. A portion of the plan area is within the City of Bakersfield and not subject to County jurisdiction.

The plan indicates that are no active oil fields in the Management Area. Active oil fields are located adjacent to near or portions of the plan area. The plan states that "[n]o commercial or industrial groundwater users have been identified within the Olcese GSA Area." An oil and gas well database maintained by CalGEM "identifies the presence of wells in the GSA Area, however, according to [CalGEM] data, the current status of these wells is 'plugged and abandoned.'"

The plan states that under Section 354.26(b)(1)) of the SGMA regulations, the following applies:

> Potential causes of Undesirable Results due to Degraded Water Quality within the Olcese GSA Area include the addition of constituents of concern (COCs) to groundwater in the principal aquifer through processes that are causatively related to water management or land use activities. Fortunately, due to hydrogeological conditions in the Olcese GSA Area, the mechanisms for this addition of COCs to the principal aquifer are quite limited due to the confined nature of the Olcese Sand Aquifer Unit. Also, owing to its location on the margin of the Kern Subbasin, the Olcese GSA Area is not vulnerable to inflows of poor-quality water from adjacent basins or areas. Direct injection of 'produced water' generated from oil field operations may occur in areas outside of the Olcese GSA Area (e.g., in the Ant Hill oil field), but those areas are generally downgradient from the Olcese GSA Area and separated from the Olcese GSA Area by several fault systems. Furthermore, such injection is regulated under the Underground Injection Control (UIC) program. Therefore, Undesirable Results for Degraded Water Quality are unlikely to occur within the Olcese GSA Area.(EKI Environment & Water 2020).

A footnote to this section of the plan states that "[d]irect injection of fluids associated with oil and natural gas production via Class II wells under the UIC program is regulated under the Safe Drinking Water Act and is limited to occur only in strata that are not designated as Underground

Sources of Drinking Water (USDWs), but injection infrastructure can leak, resulting in addition of potential COCs to USDWs" (EKI Environment & Water 2020).

BVGSA GSA GSP

The BVGSA GSP covers approximately 50,560 acres, primarily along the eastern boundary of the Western Subarea and also extending into the northern part of the Central Subarea in the Project Area.

The plan states that "[s]everal processes contribute to land subsidence. These include, in order of decreasing significance: aquifer compaction by overdraft, hydrocompaction (shallow or near-surface subsidence) of moisture deficient deposits above the water table that are wetted for the first time since deposition, petroleum reservoir compaction due to oil and gas withdrawal, and subsidence caused by tectonic forces. In addition to groundwater withdrawal, oil and gas production and tectonic forces may contribute to subsidence in or near" the plan area. The plan also states that, within the plan area, "[o]ne production well, DW-1, in the extreme south of the BVGSA went dry in 2015 during the recent drought. Water levels in this well have since recovered, and the well is back in operation. The location of DW-1, in an oil field area near Tupman is not typical of other production wells in the GSA, and no other wells in the BVGSA have ever gone dry."

Figure 2-28 of the plan identifies 77 "Sites Of Potential Groundwater Impacts," which are substantially similar to the 77 sites discussed in the KGA GSP and the HMWD GSP. Some of the mapped sites are produced water ponds. None of the sites are shown in Figure 2-28 as within the boundaries of the BVGSA. The plan states that "[o]f the 50 open cases [sites of potential groundwater impacts] within the boundaries of the Kern County Subbasin, 9 were identified as impacting groundwater within the Subbasin, however none were identified as impacting groundwater within the BVGSA." The plan states that "[s]everal processes contribute to land subsidence. These include, in order of decreasing significance: aquifer compaction by overdraft, hydrocompaction (shallow or near-surface subsidence) of moisture deficient deposits above the water table that are wetted for the first time since deposition, petroleum reservoir compaction due to oil and gas withdrawal, and subsidence caused by tectonic forces." In addition to groundwater withdrawal, the plan states that "oil and gas production and tectonic forces may contribute to subsidence in or near the BVGSA" (BVWSD GSA 2020).

Surface Water and Groundwater Quality

This section summarizes available information concerning existing surface water and groundwater quality and the effects of historical oil and gas exploration and production in the Project Area. As will be discussed in Section 4.9.3, Regulatory Setting, surface water and groundwater quality is subject to regulation under several federal, state, County, and local laws, regulations, and programs. Certain regulatory programs utilize different criteria to define "fresh" water supplies or drinking water. Not all water that is identified as "fresh" water in certain regulatory contexts is suitable for use as drinking water. The SDWA defines a groundwater aquifer with TDS concentrations of up to 10,000 mg/L or ppm as a USDW. The identification of the depth to the base of "fresh" water in many CalGEM summaries of active oil fields typically refers to groundwater with a TDS level of up to 3,000 mg/L. Almost no drinking water supplied to urban consumers in California contains TDS levels above 500 mg/L, the secondary (recommended, but not mandatory) maximum contaminant level (MCL) applicable to drinking water under state and federal law. Water supplies with TDS levels significantly above 1,000 mg/L are also less commonly used for most non-potable and agricultural irrigation in the Project Area because of the risk that dissolved ions, commonly called "salts" in high TDS water, will accumulate in and degrade the productivity of agricultural topsoils. However, CalGEM has advised that comments from CalGEM workshops indicate that farmers use water with TDS greater than 4,000 mg/L on crops.

USGS conducts periodic analyses of Project Area water quality in conjunction with state agencies and generally defines water quality in terms of the relative amount of TDS, or salt compounds. The USGS classifies water supplies as follows (USGS 2015):

- Fresh water as a supply with up to 1,000 ppm TDS;
- Slightly saline water as a supply with 1,000 ppm to 3,000 ppm TDS;
- Moderately saline water as a supply with 3,000 ppm to 10,000 ppm TDS; and
- Highly saline water as having 10,000 ppm to 35,000 ppm TDS.

In 1998, CalGEM (then DOGGR) conducted a study of potential oil and gas activity groundwater impacts that utilized a 1962 federal classification of water quality by use. As summarized in the study, Class I surface and subsurface waters are considered usable for all domestic and agricultural purposes and have TDS levels below 700 mg/L. Class II waters are considered unfit for human consumption, possibly harmful to some crops, and have TDS levels ranging from 700 to 2,000 mg/L. Class III surface and subsurface waters contain chemical concentrations that are unfit for human consumption and almost all crop use, and have TDS levels above 2,000 mg/L (DOGGR 1998). Seawater generally has a TDS content of 35,000 mg/L. Based on the USGS and CalGEM classifications, the 10,000 mg/L TDS criterion for identifying a potential USDW under the federal SDWA represents a conservative threshold that is within the range of moderate to highly saline water and could contain TDS at levels up to 20 times higher than the applicable secondary drinking water MCL. Significant treatment, potentially similar to industrial-scale water desalination facilities, would be required before water with TDS levels near 10,000 mg/L could be used for potable or most non-potable irrigation purposes.

The ~~*California State Water Resources Control Board (*~~SWRCB~~*)*~~ sets statewide policies for the protection of surface water and groundwater quality under federal and state laws that are implemented in specific regions of the state by nine RWQCBs through the adoption and enforcement of water quality control plans, commonly called "basin plans" (CVRWQCB 2004). The CVRWQCB regulates water quality in the Project Area under the Tulare Lake Basin Water Quality Control Plan (Tulare Lake Basin Plan). The Tulare Lake Basin Plan designates existing and potential beneficial uses for surface waters and groundwater in the plan area, including municipal (drinking), agricultural, industrial, recreational, and fish and wildlife uses. A list of the beneficial use designations, and the acronyms that identify these uses in the Tulare Lake Basin Plan is provided in Table 4.9-6.

Table 4.9-6: Tulare Lake Basin Plan Beneficial Use Summary

Abbreviation	Name	Description
MUN	Municipal and Domestic Supply	Uses of water for community, military, or individual water supply systems including drinking water supply
AGR	Agricultural Supply	Uses of water for farming, horticulture, or ranching, including, but not limited to, irrigation, stock watering, or support of vegetation for range grazing
IND	Industrial Service Supply	Uses of water for industrial activities that do not depend primarily on water quality, including mining, cooling water supply, hydraulic conveyance, gravel washing, fire protection, and oil well repressurization
PRO	Industrial Process Supply	Uses of water for industrial activities that depend primarily on water quality
POW	Hydropower Generation	Uses of water for hydropower generation
REC-1	Water Contact Recreation	Uses of water for recreational activities involving body contact with water where ingestion of water is reasonably possible, including swimming, wading, water-skiing, skin and scuba diving, surfing, white-water activities, fishing, and use of natural hot springs
REC-2	Non-Contact Water Recreation	Uses of water for recreational activities involving proximity to water but where there is generally no body contact with water or any likelihood of ingestion of water, including picnicking, sunbathing, hiking, beachcombing, camping, boating, tide pool and marine life study, hunting, sightseeing, and aesthetic enjoyment in conjunction with the above activities
WARM	Warm Freshwater Habitat	Includes support for reproduction and early development of warm water fish
COLD	Cold Freshwater Habitat	Uses of water that support cold water ecosystems, including preservation or enhancement of aquatic habitats, vegetation, fish, and wildlife, including invertebrates
WILD	Wildlife Habitat	Uses of water that support terrestrial or wetland ecosystems, including preservation and enhancement of terrestrial habitats or wetlands, vegetation, wildlife (e.g., mammals, birds, reptiles, amphibians, invertebrates), and wildlife water and food sources
RARE	Rare, Threatened, or Endangered Species	Uses of water that support aquatic habitats necessary, at least in part, for the survival and successful maintenance of plant and animal species established under state or federal law as rare, threatened, or endangered
SPWN	Spawning, Reproduction, and/or Early Development	Uses of water that support high quality aquatic habitats suitable for reproduction and early development of fish (limited to cold water fisheries)

Table 4.9-6: Tulare Lake Basin Plan Beneficial Use Summary

Abbreviation	Name	Description
GWR	Groundwater Recharge	Uses of water for natural or artificial recharge of groundwater for purposes of future extraction, maintenance of water quality, or halting of saltwater intrusion into freshwater aquifers
FRSH	Freshwater Replenishment	Uses of water for natural or artificial maintenance of surface water quantity or quality

Source: CVRWQCB 2004

The Tulare Lake Basin Plan also identifies applicable numerical and narrative water quality objectives that are necessary to protect each designated beneficial use and implementation programs that will achieve the applicable objectives. Commonly regulated constituents in the Tulare Lake Basin Plan include ammonia, oil and grease, salinity, suspended materials, and turbidity. The Tulare Lake Basin Plan incorporates state and federal anti-degradation policies, which require that whenever the existing quality of surface water or groundwater is higher than applicable objectives, existing water quality levels must be maintained unless it has been demonstrated that the change in water quality is consistent with the maximum benefit to the people of the state, will not unreasonably affect present and anticipated beneficial use of the water, and will not cause the water to exceed applicable water quality objectives (SWRCB 1968). Discharges that would reduce water quality must be specifically permitted by the CVRWQCB through the issuance of WDRs (CVRWQCB 2004).

The Tulare Lake Basin Plan identifies several watershed drainage areas, or hydrologic units that contain streams, ephemeral drainages and other surface waters in the Project Area. As shown on Figure 4.9-9, streams in the eastern Subarea are generally within hydrologic units 554 and 555. Western Subarea streams are included in hydrologic units 556 and 559, and valley floor waters, including surface water in the central Subarea, are located in hydrologic units 557 and 558.

The designated beneficial uses for surface waters in each hydrologic unit in the Project Area are summarized in Table 4.9-7. Several surface waters have been designated for more than one beneficial use.

Groundwater beneficial uses are designated in the Tulare Lake Basin Plan for detailed analysis units (DAUs), which are subunits that have been identified within the overall region. The locations of the DAUs as mapped by the CVRWQCB within the Project Area are shown on Figure 4.9-10.

The designated beneficial uses for each DAU groundwater unit in the Tulare Lake Basin Plan are summarized in Table 4.9-8. Groundwater in several areas has been designated for more than one beneficial use.

Table 4.9-7: Tulare Lake Basin Plan Surface Water Beneficial Use Designations

Stream[a]	MUN	AGR	IND	PRO	POW	REC-1	REC-2	WARM	COLD	WILD	RARE	SPW	GWR	FRSH
554, 557 Kern River														
Above Lake Isabella	●				●	●	●	●	●	●	●	●		●
Lake Isabella	●					●	●	●	●	●				●
Lake Isabella to KR-1[b]	●					●	●	●	●	●	●			
Below KR-1[b]	●	●	●	●	●	●	●	●		●	●		●	
555, 558 Poso Creek	●					●	●	●	●	●			●	●
552 Mill Creek, Source to Kings River	●					●	●	●		●			●	●
552, 553, 554, 555 Other East Side Streams	●	●				●	●	●	●	●			●	
556, 559 West Side Streams	●		●	●		●	●	●		●	●		●	
551, 557, 558 Valley Floor Waters	●		●	●		●	●	●		●	●		●	

Notes:
Table is a partial reproduction of the Basin Plan Table II-1 for the Tulare Lake Hydrologic Basin (CVRWQCB 2004).
[a] Bold indicates surface waters that are in the Project Area.
[b] KR-1: Southern California Edison Kern River Powerhouse No. 1.

Key:
AGR = agricultural supply
COLD = cold freshwater habitat
FRSH = freshwater replenishment
GWR = groundwater recharge
IND = industrial service supply
MUN = municipal and domestic supply
POW = hydropower generation
PRO = industrial process supply
RARE = rare, threatened, or endangered species
REC-1 = water contact recreation
REC-2 = non-contact water recreation
SPWN = spawning, reproduction, and/or early development
WARM = warm freshwater habitat
WILD = wildlife habitat

Table 4.9-8: Tulare Lake Basin Plan Groundwater Beneficial Use Designations

Hydrologic Unit	DAU[a]	MUN	AGR	IND	PRO	REC-1	REC-2	WILD
Kern County Basin								
	245	●	●	●				
	254[b]	●	●	●	●	●	●	●
	255	●	●	●				●
	256	●	●	●	●			
	257	●	●	●		●		
	258	●	●	●	●			
	259[c]	●	●	●				
	260	●		●				
	261	●	●	●				
All Other Groundwaters [d]		●						

Source: Basin Plan Table II-2 for the Tulare Lake Hydrologic Basin (CVRWQCB 2004)

Notes:

[a] Groundwater contained in the lower Transition Zone and Santa Margarita formation within 3,000 feet of the Kern Oil and Refining Company proposed injection wells in Section 25, T30S, R28E, MDB&M, is not suitable, or potentially suitable, for municipal or domestic supply (MUN).

[b] Groundwater contained in the basal Etchegoin formation, Chanac formation, and Santa Margarita formation within, and extending to one-quarter mile outside the administrative boundary of the Fruitvale Oil Field, as defined by the State of California, Department of Conservation, Division of Oil and Gas in Application for Primacy in the Regulation of Class II Injection Wells Under Section 1425 of the Safe Drinking Water Act, dated April 1981, is not suitable, or potentially suitable, for municipal or domestic supply (MUN). However, the upper groundwater zone (groundwater to a depth of 3,000 feet) retains the MUN beneficial use.

© Groundwater and spring water within 0.5-mile radius of the McKittrick Waste Treatment (formerly Liquid Waste Management) site in Section 29, T30S, R22E, MDB&M, have no beneficial uses.

[d] Groundwater in the San Joaquin, Etchegoin, and Jacalitos formations within 0.5 mile of existing surface impoundments P-1, P-2, P-3, P-4, P-4 1/2, P-5, P-6, P-7, P-8, P-9, P-10, P-11, P-12/12A, P-13, P-14, P-15, P-16, P-17, P-18, P- 19, and P-20, and proposed surface impoundments P-21, P-24, P-25, P-27, P-28, and P-29 at the Kettleman Hills Facility (Sections 33 and 34, T22S, R18E, and Section 3, T23S, R18E, MDB&M) of Chemical Waste Management is not a municipal or domestic supply (MUN).

Key:
AGR = agricultural supply
DAU = detailed analysis unit.
IND = industrial service supply
MUN = municipal and domestic supply
PRO = industrial process supply
REC-1 = water contact recreation
REC-2 = non-contact water recreation
WILD = wildlife habitat

Consistent with state drinking water policy (SWRCB 1988), the Tulare Lake Basin Plan designates all groundwater within the Project Area for municipal (MUN) beneficial use, subject to the potential removal of, or exception to this designation in specific locations by means of a formal basin plan amendment process. The CVRWQCB considers the following criteria for making exceptions to the groundwater MUN beneficial use designation: (1) TDS levels in an aquifer must exceed 3,000 mg/L (or an equivalent measure of electrical conductivity) and the aquifer cannot be reasonably expected to supply a public water system; (2) there is contamination, either by natural processes or by human activity (unrelated to a specific pollution incident), that cannot reasonably be treated for domestic use using either best management practices (BMPs) or best economically achievable treatment practices; (3) the water source cannot provide sufficient water to supply a single well capable of producing an average, sustained yield of 200 gallons per day; or (4) the aquifer is regulated as a geothermal energy producing source or has been exempted administratively pursuant to the federal UIC program for the production of hydrocarbon or geothermal energy, provided that injected fluids do not constitute a hazardous waste. Figure 4.9-11 shows approved groundwater beneficial use aquifer exemptions.

The SWRCB has adopted a “sources of drinking water” policy that states that all ground and surface waters of the state are considered suitable or potentially suitable for municipal or domestic water supply and should be so designated by each RWQCB, subject to certain exceptions. One exception listed in the policy includes an aquifer that “is regulated as a geothermal energy producing source or has been exempted administratively pursuant to 40 Code of Federal Regulations (CFR), Section 146.4 for the purpose of underground injection of fluids associated with the production of hydrocarbon or geothermal energy, provided that these fluids do not constitute a hazardous waste under 40 CFR 261.3” (SWRCB 1988, 2006). As discussed below, state and federal agencies are currently updating the status of aquifer exemptions in the Project Area. Figure 49-11 identifies the locations in the Project Area where the groundwater MUN beneficial use has been removed by the CVRWQCB in the Tulare Lake Basin Plan.

The Tulare Lake Basin Plan identifies waters that are not attaining applicable water quality standards, or impaired waters, after technology-based limits and the best available technology used for pollutant management have been implemented in accordance with Section 303(d) of the Clean Water Act (CWA). There are no impaired water bodies listed under Section 303(d) of the CWA in the Project Area.

Surface water resources in the Project Area primarily consist of rainfall and snowmelt flows in natural streams and watercourses, generally originating from the eastern side of the Tulare Lake Hydrologic Basin and springs and upland watersheds in the Sierra Nevada range, and imported water delivered to the region through the SWP and federal CVP water recovery and conveyance facilities. Ephemeral watercourses are located in the western portion of the Project Area and carry water for brief periods only during significant storm events. The distribution of surface waters within the Project Area is discussed in more detail in Section 4.4, Biological Resources of the 2015 FEIR, and is shown on Figure 4.4-3 of that document. The SWP and CVP systems are discussed in more detail in Section 4.17, Utilities and Service Systems. As shown in Table 4.9-1, in 2012, oil and gas production utilized about 8,778 AFY of M&I water in addition to 234,959 AF of produced water. In an average year, urban water demand is about 235,000 AFY, and agricultural demand is about 2.67 million AFY in the Project Area. The amount of Project Area surface water supplies that are used for oil and gas exploration and production varies from year to year in accordance with hydrologic conditions. In drier years, groundwater is used to a greater extent than surface supplies (see Section 4.17, Utilities and Service Systems).

In December 2016, the EPA released a final version of a study titled *Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States* (EPA 2016a). As summarized by the EPA, the report was unable to fully assess the potential impacts on drinking water resources both locally and nationally due to data gaps and uncertainties. The report stated that "[i]t was not possible to calculate or estimate the national frequency of impacts on drinking water resources from activities in the hydraulic fracturing water cycle or fully characterize the severity of impacts" (EPA 2016a) Impacts from hydraulic fracturing activities were found to be more frequent or severe under the following circumstances (EPA 2016b):

- Water withdrawals for hydraulic fracturing in times or areas of low water availability, particularly in areas with limited or declining groundwater resources;
- Spills during the handling of hydraulic fracturing fluids and chemicals or produced water that result in large volumes or high concentrations of chemicals reaching groundwater resources;
- Injection of hydraulic fracturing fluids into wells with inadequate mechanical integrity, allowing gases or liquids to move to groundwater resources;
- Injection of hydraulic fracturing fluids directly into groundwater resources;
- Discharge of inadequately treated hydraulic fracturing wastewater to surface water; and
- Disposal or storage of hydraulic fracturing wastewater in unlined pits, resulting in contamination of groundwater resources.

Additional information on groundwater quality and oil and gas activities is provided above for each of the KCS GSPs and management area plans in the Project Area.

Surface Water Quality Data

Surface water quality data for the Project Area and each Subarea was obtained by identifying available analysis results for current and historical river, creek and stream sampling locations maintained by the state Surface Water Ambient Monitoring Program, the state Irrigated Lands Regulatory Program (SWRCB 2012), the California Environmental Data Exchange Network (SWRCB 2012), the USGS National Water Information System (USGS 2014), and the EPA Storage and Retrieval (STORET) Legacy Data Center (EPA 2014). Sampling data from agricultural canals or tile drains was not utilized because constructed facilities used in crop production are not representative of natural water quality conditions in the Project Area. The locations of the water sampling sites that were used in the surface water quality analysis are shown on Figure 4.9-12.

The extent of the available surface water quality data and coverage varies for each Project Subarea. There are 15 unique and 17 total sampling sites in the Eastern Subarea, and current water quality data are available for six of these locations. The remaining sampling sites are no longer in use, and historical data for these locations were obtained from the EPA STORET database. There are two unique and three total surface water sampling stations in the Central Subarea. Eleven surface water quality sample sites were identified in the Western Subarea, but none is currently in operation and historical data for these locations were obtained from the EPA STORET database.

Tables 4.9-9 and 4.9-10 summarize water quality data for the Kern River at four locations from 2004 through 2006, and for Deer Creek, Poso Creek, and El Paso Creek at four locations from 2009 through 2012.

Table 4.9-11 summarizes water quality data available from 2002 through 2012, and Table 4.9-12 summarizes historical water quality data from samples taken from 1951 through 1991 for each of the Project Subareas. Surface water quality data for the Western Subarea are not available after 1991, and information for the Western Subarea is not included in Table 4.9-11.

Stream, river, and creek data for the period 2002 to 2012 (Tables 4.9-9 to 4.9-11) do not indicate significant differences between the Central and Eastern Subareas. Surface water results in both Subareas exhibit similar levels of TDS, hardness, chloride, sodium, and specific conductivity. The data suggest that surface water quality based on TDS levels, specific conductance or hardness is slightly higher in the Eastern Subarea, most likely due to the Subarea's closer proximity to stream and spring flows from the Sierra Nevada. On average, surface waters in the Central and Eastern Subareas have TDS levels below the secondary drinking water MCL of 500 mg/L.

Data from 1951 to 1991 (Table 4.9-12) is generally consistent with more recent surface water quality sampling results, and indicates that surface water quality improves from west to east in the Project Area. As shown in Table 4.9-12, TDS, alkalinity, nitrate, hardness, chloride, sodium, specific conductivity, and boron levels were typically higher in the Western Subarea than in the Central or Eastern Subareas. These results likely reflect the fact that watercourses on the western side of the Project Area flow only during periods of sustained rainfall and traverse through marine rocks and soils that contain salts and other compounds that rapidly dissolve in water. Surface water in the eastern Project Area generally flows more frequently and through granitic channels that do not mobilize constituents to the same extent.

As discussed in Section 4.17, Utilities and Service Systems, the SWP and CVP supply systems import water pumped from the southern edge of the Sacramento Delta and collected in reservoirs located along the western face of the Sierra Nevada range to the Project Area. Water quality data for the CVP system is maintained by the KCWA, the region's primary imported water wholesale supplier. Water quality data for the SWP system is maintained by the DWR. Table 4.9-13 summarizes available water quality data for CVP supplies, and Table 4.9-14 summarizes water quality data for SWP imports in the Project Area.

The sampling results in Tables 4.9-13 and 4.9-14 show that SWP and CVP supplies exhibit high levels of water quality. CVP supplies have an average specific conductance (an alternative measure of dissolved inorganic materials and ions) of 210 microSiemens per centimeter and TDS of 130 mg/L. SWP water has a slightly higher average specific conductance of 460 microSiemens per centimeter and TDS concentration of 260 mg/L. These levels are below the secondary drinking water MCL for TDS. Other constituents in Project Area imported water are below applicable primary and secondary drinking water MCLs.

Although TDS levels in SWP and CVP imported water are relatively low, the Tulare Lake Basin Plan states that the Project Area is a generally closed hydrological basin with little surface and subsurface outflow. As a result, salts contained in imported water remain and accumulate within due to imported water. The Tulare Lake Basin Plan indicates that the paramount water quality problem in the Project Area is the accumulation of salts (CVRWQCB 2004).

Surface Water Quality and Existing Oil and Gas Operations

There have been no studies or reports indicating that current oil field activities significantly affect Project Area surface water quality. Several decades ago, produced water from major Project Area oil fields was discharged into local watercourses, including the Kern River (Christie 1999). Subsequently enacted state and federal laws prohibit the discharge of solid wastes or fluids associated with oil and gas exploration and production into surface waters, except as may be allowed by an applicable permit. A review of publicly available discharge permits issued by the CVRWQCB did not identify any currently applicable permitted direct discharges of produced water or other materials associated with oil and gas exploration or production into Project Area surface waters. In 2007, the CVRWQCB issued WDRs, a form of discharge permit under state law, for the discharge of up to 1.68 million gallons per day of treated produced water into an ephemeral tributary of Poso Creek. The permit was rescinded in 2013, and the produced water is now injected into wells regulated under the UIC program for EOR purposes or disposal (CVRWQCB 2013a).

Table 4.9-9: Kern River Water Quality Data Summary 2004 to 2006

Water Quality Parameters	Units	Station Name: Ker MM14/MM15 (Station Code 554KER070)						Station Name: Rancheria Road (Station Code 554KER080)					
		Avg.	Med.	Min	Max	N	Date Range	Avg.	Med.	Min	Max	N	Date Range
General Water Quality													
Alkalinity, Total	mg/L as $CaCO_3$	38	-	-	-	1	06/26/03	40	40	39	40	2	6/26/03 – 06/26/03
Ammonium	mg/L as N	0.024	0.019	0.0086	0.053	8	12/12/02 - 05/26/04	0.065	0.018	ND	0.232	7	12/12/02- 05/26/04
Calcium	mg/L	10	-	-	-	1	06/26/03	11	-	-	-	1	6/26/03
Chloride	mg/L	3.7	-	-	-	1	06/26/03	3.7	-	-	-	1	6/26/03
Dissolved oxygen	mg/L	11	11	10	13	9	03/27/02 - 05/26/04	11	11	10	12	9	3/27/02- 05/26/04
Magnesium	mg/L	1.6	-	-	-	1	06/26/03	1.6	-	-	-	1	6/26/03
Nitrate + Nitrite	mg/L as N	0.11	0.073	0.026	0.28	6	12/12/02 - 05/26/04	0.12	0.088	0.037	0.28	6	12/12/02- 05/26/04
Nitrate	mg/L as N	ND	-	-	-	1	06/26/03	ND	-	-	-	1	6/26/03
Nitrite	mg/L as N	ND	-	-	-	1	06/26/03	ND	-	-	-	1	6/26/03
Nitrogen, Total Kjeldahl	mg/L	0.36	0.33	ND	0.50	6	03/27/02 - 05/26/04	0.46	0.51	ND	0.57	6	12/12/02- 05/26/04
Orthophosphate, Dissolved	mg/L as P	0.036	0.034	0.01	0.073	5	12/12/02 - 05/26/04	0.037	0.034	0.0076	0.076	5	12/12/02- 05/26/04
pH	pH units	8.4	8.5	8.1	8.6	9	03/27/02 - 05/26/04	8.4	8.5	8.1	8.6	9	3/27/02-5/26/1904
Phosphorus, Total	mg/L as P	0.076	0.050	0.045	0.13	5	12/12/02 - 05/26/04	0.079	0.050	0.046	0.15	5	12/12/02 – 05/26/04
Potassium	mg/L	1.6	-	-	-	1	06/26/03	1.6	-	-	-	1	6/26/03
Sodium	mg/L	7.7	-	-	-	1	06/26/03	8.3	8.3	8.2	8.3	2	6/26/03 – 06/26/03
Specific conductivity	µS/cm	139	130	96	178	9	03/27/02 - 05/26/04	150	137	114	195	8	6/20/02 – 05/26/04
Sulfate	mg/L	5.2				1	06/26/03	6.5				1	6/26/03
Temperature	°C	15	15	8.7	22	9	03/27/02 - 05/26/04	16	14	10	22	9	3/27/02 – 05/26/04
Total dissolved solids	mg/L	76	-	-	-	1	06/26/03	71	-	-	-	1	6/26/03

Table 4.9-9: Kern River Water Quality Data Summary 2004 to 2006

Water Quality Parameters	Units	Station Name: Ker MM14/MM15 (Station Code 554KER070)						Station Name: Rancheria Road (Station Code 554KER080)					
		Avg.	Med.	Min	Max	N	Date Range	Avg.	Med.	Min	Max	N	Date Range
Metals													
Iron, Total	µg/L /L	220	-	-	-	1	06/26/03	185	185	172	198.5	2	06/26/03 – 06/26/03
Manganese, Total	µg/L	46	-	-	-	1	06/26/03	44	-	-	-	1	06/26/03
Other Water Quality Parameters													
Boron	mg/L	0.75	-	-	-	1	06/26/03	0.0775	0.0775	0.0771	0.078	2	06/26/03 – 06/26/03
Microbial Indicators													
Coliform, Fecal	MPN/100 mL	20	8.0	ND	83	9	03/27/02 – 05/26/04	30	5.5	2.0	140	10	03/27/02 – 05/26/04
Coliform, Total	MPN/100 mL	130	80	28	276	9	03/27/02 – 05/26/04	133	125	8.0	273	10	03/27/02 – 05/26/04
E. Coli	MPN/100 mL	19	4.0	ND	83	9	03/27/02 – 05/26/04	32	7.0	2.0	151	9	03/27/02 – 05/26/04
Fecal Streptococci	MPN/100 mL	47	47	17	77	2	03/27/02 – 06/20/02	89	89	16	162	2	03/27/02 – 06/20/02

Source: Appendix S-1, 2015 FEIR
Key:
°C = degrees Celsius
Avg = Average
Med = Median
mg/L = milligrams per liter
mL= milliliter
MPN = Most Probable Number
N = number of results
ND = not detected above the method reporting limit
P = Phosphorus
µg/L = micrograms per liter
µS/cm = microSiemens per centimeter

Table 4.9-10: Deer Creek, Poso Creek, and El Paso Creek Water Quality Data Summary 2009 to 2012

Water Quality Parameters	Units	Station Name: Deer Creek at Road 120 (Station Code 558DCR120)						Station Name: Deer Creek at Road 176 (Station Code 558DCR178)					
		Average	Median	Min[(a)]	Max[(b)]	N	Date Range	Average	Med.	Min[(a)]	Max[(b)]	N	Date Range
General Water Quality													
Ammonia, Total	mg/L as N	ND	-	-	-	18	5/12/2009 - 4/18/2012	ND	ND	ND	0.16	19	5/12/2009 - 4/18/2012
Calcium	mg/L	8.0	4.3	2.0	21	18	5/12/2009 - 4/18/2012	7.2	4.0	1.9	19	19	5/12/2009 - 4/18/2012
Color	color units	41	15	8.4	108	18	5/12/2009 - 4/18/2012	33	13	7.7	150	19	5/12/2009 - 4/18/2012
Dissolved Oxygen	mg/L	8.7	8.4	7.7	10	19	5/12/2009 - 4/18/2012	8.9	8.5	7.7	11	19	5/12/2009 - 4/18/2012
Hardness	mg/L as $CaCO_3$	26	14	6.5	70	18	5/12/2009 - 4/18/2012	24	13	6.0	66	19	5/12/2009 - 4/18/2012
Magnesium, Total	mg/L	1.54	ND	ND	4.4	18	5/12/2009 - 4/18/2012	1.5	ND	ND	4.36	19	5/12/2009 - 4/18/2012
Nitrate + Nitrite, Total	mg/L as N	0.15	0.050	ND	0.50	18	5/12/2009 - 4/18/2012	0.19	0.050	ND	0.56	19	5/12/2009 - 4/18/2012
Nitrogen, Total Kjeldahl	mg/L	ND	ND	ND	1.0	18	5/12/2009 - 4/18/2012	ND	ND	ND	0.83	19	5/12/2009 - 4/18/2012
OrthoPhosphate as P, Dissolved	mg/L	0.069	0.060	ND	0.16	18	5/12/2009 - 4/18/2012	0.062	0.041	0.011	0.15	19	5/12/2009 - 4/18/2012
pH	pH units	7.8	7.7	7.1	8.8	19	5/12/2009 - 4/18/2012	7.6	7.6	7.1	8.2	19	5/12/2009 - 4/18/2012
Phosphorus, Total	mg/L as P	0.041	0.018	ND	0.14	18	5/12/2009 - 4/18/2012	0.05	0.02	ND	0.20	19	5/12/2009 - 4/18/2012
Specific Conductivity, Total	µS/cm	74	50	21	200	19	5/12/2009 - 4/18/2012	76	49	20	192	19	5/12/2009 - 4/18/2012
Temperature	°C	21	22	15	29	19	5/12/2009 - 4/18/2012	18	19	11	25	19	5/12/2009 - 4/18/2012
Total Dissolved Solids	mg/L	62	37	21	152	18	5/12/2009 - 4/18/2012	52	36	14	132	19	5/12/2009 - 4/18/2012
Total organic carbon	mg/L	3.3	2.5	1.1	8.3	18	5/12/2009 - 4/18/2012	3.0	2.4	1.0	6.8	19	5/12/2009 - 4/18/2012

Table 4.9-10: Deer Creek, Poso Creek, and El Paso Creek Water Quality Data Summary 2009 to 2012

Water Quality Parameters	Units	Station Name: Deer Creek at Road 120 (Station Code 558DCR120)						Station Name: Deer Creek at Road 176 (Station Code 558DCR178)					
		Average	Median	Min[(a)]	Max[(b)]	N	Date Range	Average	Med.	Min[(a)]	Max[(b)]	N	Date Range
Total Suspended Solids	mg/L	8.2	6.3	ND	20	18	5/12/2009 - 4/18/2012	13	13	ND	33	19	5/12/2009 - 4/18/2012
Turbidity, Total	NTU	6.6	5.3	1.2	13	18	5/12/2009 - 4/18/2012	5.7	4.4	1.3	13	19	5/12/2009 - 4/18/2012
Metals													
Arsenic, Total	µg/L	1.5	1.7	ND	1.9	7	5/12/2009 - 8/17/2010	1.6	1.6	1.1	2.2	8	5/12/2009 - 8/17/2010
Cadmium, Dissolved	µg/L	ND	-	-	-	7	5/12/2009 - 8/17/2010	ND	ND	ND	0.10	8	5/12/2009 - 8/17/2010
Cadmium, Total	µg/L	ND	ND	ND	0.14	7	5/12/2009 - 8/17/2010	ND	-	-	-	8	5/12/2009 - 8/17/2010
Copper, Dissolved	µg/L	3.6	4.2	1.6	4.5	7	5/12/2009 - 8/17/2010	6.5	3.2	1.7	18	8	5/12/2009 - 8/17/2010
Copper, Total	µg/L	8.4	5.8	4.1	20	7	5/12/2009 - 8/17/2010	6.9	6.2	2.9	14	8	5/12/2009 - 8/17/2010
Lead, Dissolved	µg/L	ND	-	-	-	7	5/12/2009 - 8/17/2010	0.24	ND	ND	0.80	8	5/12/2009 - 8/17/2010
Lead, Total	µg/L	0.57	0.60	0.40	0.79	7	5/12/2009 - 8/17/2010	1.3	0.68	0.37	4.2	8	5/12/2009 - 8/17/2010
Molybdenum, Total	µg/L	1.6	ND	ND	4.6	7	5/12/2009 - 8/17/2010	1.3	ND	ND	3.9	8	5/12/2009 - 8/17/2010
Nickel, Dissolved	µg/L	ND	-	-	-	7	5/12/2009 - 8/17/2010	ND	ND	ND	1.6	8	5/12/2009 - 8/17/2010
Nickel, Total	µg/L	1.0	ND	ND	2.8	7	5/12/2009 - 8/17/2010	ND	1.0	ND	1.5	8	5/12/2009 - 8/17/2010
Selenium, Total	µg/L	ND	-	-	-	7	5/12/2009 - 8/17/2010	ND	-	-	-	8	5/12/2009 - 8/17/2010
Zinc, Dissolved	µg/L	ND	-	-	-	7	5/12/2009 - 8/17/2010	ND	ND	ND	11	8	5/12/2009 - 8/17/2010
Zinc, Total	µg/L	11	11.2	ND	18	7	5/12/2009 - 8/17/2010	13	ND	ND	24	8	5/12/2009 - 5/12/2009
Microbial Indicators													
Coliform, Fecal	MPN/100 mL	165	80.0	22	500	20	5/12/2009 - 4/18/2012	138	80	13	300	21	5/12/2009 - 4/18/2012
Coliform, Total	MPN/100 mL	1667	2200	300	2420	35	5/12/2009 - 4/18/2012	1775	1700	166	2420	39	5/12/2009 - 4/18/2012
E. coli	MPN/100 mL	100	56	8.4	302	17	5/12/2009 - 4/18/2012	120	64	14	353	20	5/12/2009 - 4/18/2012

Table 4.9-10: Deer Creek, Poso Creek, and El Paso Creek Water Quality Data Summary 2009 to 2012

Water Quality Parameters	Units	Station Name: Deer Creek at Road 120 (Station Code 558DCR120)						Station Name: Deer Creek at Road 176 (Station Code 558DCR178)					
		Average	Median	Min[(a)]	Max[(b)]	N	Date Range	Average	Med.	Min[(a)]	Max[(b)]	N	Date Range
Other Water Quality Parameters													
Boron, Total	µg/L	17	ND	ND	43	7	5/12/2009 - 8/17/2010	13	10	ND	27	8	5/12/2009 - 8/17/2010
Pesticides[(c)]													
Chlorpyrifos, Total	µg/L	ND	ND	ND	0.020	6	5/12/2009 - 8/17/2010	ND	-	-	-	7	5/12/2009 - 8/17/2010
Diazinon, Total	µg/L	ND	-	-	-	9	5/12/2009 - 8/17/2010	ND	-	-	-	10	5/12/2009 - 8/17/2010
Dichlorvos, Total	µg/L	ND	-	-	-	6	5/12/2009 - 8/17/2010	ND	-	-	-	7	5/12/2009 - 8/17/2010
Phosmet, Total	µg/L	ND	-	-	-	6	5/12/2009 - 8/17/2010	ND	-	-	-	7	5/12/2009 - 8/17/2010
Trifluralin, Total	µg/L	ND	-	-	-	6	5/12/2009 - 8/17/2010	ND	-	-	-	7	5/12/2009 - 8/17/2010
General Water Quality													
Ammonia, Total	mg/L as N	ND	ND	ND	0.20	9	3/24/2010 - 4/4/2012	0.53	0.53	0.22	0.827	2	3/26/2011 - 4/18/2011
Calcium	mg/L	27	26	22	33	9	3/24/2010 - 4/4/2012	62	62	57	67	2	3/26/2011 - 4/18/2011
Color	color units	-	-	-	-	-	-	-	-	-	-	-	-
Oxygen, Dissolved, Total	mg/L	8.8	9	7.8	9.7	9	3/24/2010 - 4/4/2012	8.3	8.3	7.6	8.9	2	3/26/2011 - 4/18/2011
Hardness	mg/L as CaCO3	92	88	76	111	9	3/24/2010 - 4/4/2012	234	234	218	250	2	3/26/2011 - 4/18/2011
Magnesium, Total	mg/L	5.9	5.7	5.0	7.0	9	3/24/2010 - 4/4/2012	19	19	18	20	2	3/26/2011 - 4/18/2011
Nitrate + Nitrite, Total	mg/L as N	0.41	0.20	0.07	0.92	9	3/24/2010 - 4/4/2012	2.6	2.6	1.9	3.4	2	3/26/2011 - 4/18/2011
Nitrogen, Total Kjeldahl	mg/L	ND	ND	ND	1.10	9	3/24/2010 - 4/4/2012	1.3	1.3	0.61	1.9	2	3/26/2011 - 4/18/2011
OrthoPhosphate as P, Dissolved	mg/L	0.50	0.54	0.25	0.62	9	3/24/2010 - 4/4/2012	0.64	0.64	0.51	0.77	2	3/26/2011 - 4/18/2011
pH	pH units	8.2	8.2	7.4	8.6	9	3/24/2010 - 4/4/2012	8.6	8.6	8.5	8.7	2	3/26/2011 - 4/18/2011

Table 4.9-10: Deer Creek, Poso Creek, and El Paso Creek Water Quality Data Summary 2009 to 2012

Water Quality Parameters	Units	Station Name: Deer Creek at Road 120 (Station Code 558DCR120)						Station Name: Deer Creek at Road 176 (Station Code 558DCR178)					
		Average	Median	Min[(a)]	Max[(b)]	N	Date Range	Average	Med.	Min[(a)]	Max[(b)]	N	Date Range
Phosphorus, Total	mg/L as P	0.14	0.16	0.020	0.21	9	3/24/2010 - 4/4/2012	0.61	0.61	0.37	0.85	2	3/26/2011 - 4/18/2011
Specific Conductivity, Total	µS/cm	269	262	223	332	18	3/24/2010 - 4/4/2012	448	450	411	481	4	3/26/2011 - 4/18/2011
Temperature	°C	21	18	15	29	9	3/24/2010 - 4/4/2012	20	20	14	26	2	3/26/2011 - 4/18/2011
Total Dissolved Solids	mg/L	191	184	155	226	9	3/24/2010 - 4/4/2012	297	297	282	312	2	3/26/2011 - 4/18/2011
Total organic carbon	mg/L	5.6	5.8	4.0	7.0	9	3/24/2010 - 4/4/2012	6.0	6.0	5.9	6.1	2	3/26/2011 - 4/18/2011
Total Suspended Solids, Particulate	mg/L	29	28	ND	50	9	3/24/2010 - 4/4/2012	212	212	138	286	2	3/26/2011 - 4/18/2011
Turbidity, Total	NTU	17	16	3.3	33	9	3/24/2010 - 4/4/2012	171	171	97	245	2	3/26/2011 - 4/18/2011
Metals													
Arsenic, Total	µg/L	8.2	8.2	8.1	8.3	2	3/24/2010 - 4/27/2010	-	-	-	-	-	-
Cadmium, Dissolved	µg/L	ND	-	-	-	2	3/24/2010 - 4/27/2010	-	-	-	-	-	-
Cadmium, Total	µg/L	ND	-	-	-	2	3/24/2010 - 4/27/2010	-	-	-	-	-	-
Copper, Dissolved	µg/L	7.1	7.1	4.3	9.9	2	3/24/2010 - 4/27/2010	-	-	-	-	-	-
Copper, Total	µg/L	5.7	5.7	4.9	6.5	2	3/24/2010 - 4/27/2010	-	-	-	-	-	-
Lead, Dissolved	µg/L	ND	-	-	-	2	3/24/2010 - 4/27/2010	-	-	-	-	-	-
Lead, Total	µg/L	0.78	0.78	0.64	0.93	2	3/24/2010 - 4/27/2010	-	-	-	-	-	-

Table 4.9-10: Deer Creek, Poso Creek, and El Paso Creek Water Quality Data Summary 2009 to 2012

Water Quality Parameters	Units	Station Name: Deer Creek at Road 120 (Station Code 558DCR120)						Station Name: Deer Creek at Road 176 (Station Code 558DCR178)					
		Average	Median	Min[(a)]	Max[(b)]	N	Date Range	Average	Med.	Min[(a)]	Max[(b)]	N	Date Range
Molybdenum, Total	µg/L	8.9	-	-	-	1	4/27/2010	-	-	-	-	-	-
Nickel, Dissolved	µg/L	1.9	1.9	ND	3.1	2	3/24/2010 - 4/27/2010	-	-	-	-	-	-
Nickel, Total	µg/L	1.2	1.2	1.1	1.4	2	3/24/2010 - 4/27/2010	-	-	-	-	-	-
Selenium, Total	µg/L	ND	-	-	-	2	3/24/2010 - 4/27/2010	-	-	-	-	-	-
Zinc, Dissolved	µg/L	ND	-	-	-	2	3/24/2010 - 4/27/2010	-	-	-	-	-	-
Zinc, Total	µg/L	11	11	ND	12	2	3/24/2010 - 4/27/2010	-	-	-	-	-	-
Microbial Indicators													
Coliform, Fecal	MPN/100 mL	578	500	23	1700	9	3/24/2010 - 4/4/2012	2650	2650	535	4765	2	3/26/2011 - 4/18/2011
Coliform, Total	MPN/100 mL	2360	2419	331	5450	18	3/24/2010 - 4/4/2012	9960	3710	2419	26250	4	3/26/2011 - 4/18/2011
E. coli	MPN/100 mL	568	454	33	1760	9	3/24/2010 - 4/4/2012	833	833	412	1253	2	3/26/2011 - 4/18/2011
Other Water Quality Parameters													
Boron, Total	µg/L	63	63	54	73	2	3/24/2010 - 4/27/2010	-	-	-	-	-	-
Pesticides(c)													
Chlorpyrifos, Total	µg/L	0.036	ND	ND	0.084	3	3/24/2010 - 4/27/2010	-	-	-	-	-	-
Diazinon, Total	µg/L	0.026	ND	ND	0.053	3	3/24/2010 - 4/27/2010	-	-	-	-	-	-
Dichlorvos, Total	µg/L	ND	ND	ND	0.14	3	3/24/2010 - 4/27/2010	-	-	-	-	-	-

Table 4.9-10: Deer Creek, Poso Creek, and El Paso Creek Water Quality Data Summary 2009 to 2012

Water Quality Parameters	Units	Station Name: Deer Creek at Road 120 (Station Code 558DCR120)						Station Name: Deer Creek at Road 176 (Station Code 558DCR178)					
		Average	Median	Min[(a)]	Max[(b)]	N	Date Range	Average	Med.	Min[(a)]	Max[(b)]	N	Date Range
Phosmet, Total	µg/L	ND	ND	ND	0.10	3	3/24/2010 - 4/27/2010	-	-	-	-	-	-
Trifluralin, Total	µg/L	ND	ND	ND	0.047	3	3/24/2010 - 4/27/2010	-	-	-	-	-	-

Source: 2015 FEIR Appendix S-1 (SREIR Volume 5) (Central Valley RWQCB ILRP, data available from CEDEN (SWRCB 2012) and STORET Data Warehouse (EPA 2014))
Notes:
Avg
(a) Minimum value calculated as the 5th percentile. When one or more result is ND, the minimum is reported as ND.
(b) Maximum value calculated as the 95th percentile.
(c) For Deer Creek at Road 120 and Deer Creek at Road 176, 76 additional pesticides were measured (N = 2 to 9) between 2009 and 2010 and were not detected. For Poso Creek at Zerker Road, 53 additional pesticides were measured (N = 1 to 3) in 2010 and were not detected. No pesticides data is reported for El Paso Creek.
Where "ND", average, median, minimum, and maximum are calculated assuming a value equal to one-half the reporting limit.

Key:
°C = degrees Celsius
Avg = Average
ILRP = Irrigated Lands Regulatory Program
Med = Median
mg/L = milligrams per liter
mL = milliliter
N = number of results
ND = not detected above the method reporting limit
P = Phosphorus
RWQCB = Regional Water Quality Control Board
µg/L = micrograms per liter
µScm = unit of conductivity

Table 4.9-11: Project Subarea Surface Water Quality Data Summary 2002 to 2012

Water Quality Parameters	Units	Western					Central					Eastern				
		Avg	Median	Min	Max	N[a]	Avg	Median	Min	Max	N[a]	Avg	Median	Min	Max	N[a]
General Water Quality																
Alkalinity, Total	mg/L as $CaCO_3$	*(no data available from SWAMP or ILRP for rivers and creeks in this sub-area)*					61	63	57	64	1	39	39	38	40	2
Ammonia, Total	mg/L as N						0.16	0.10	ND	0.8	4	0.033	0.018	ND	0.23	5
Calcium	mg/L						28	20	2.0	67	4	9.4	10	1.9	19	3
Chloride	mg/L						5.0	5.1	3.5	6.4	1	3.7	3.7	3.7	3.7	2
Color	color units						31	18	8.4	108	2	33	13	7.7	150	1
Dissolved oxygen	mg/L						8.8	8.7	7.7	10	2	10	10	7.6	13	6
Hardness	mg/L as $CaCO_3$						100	68	6.5	250	4	24	13	6.0	66	1
Magnesium, Total	mg/L						7.3	5.7	ND	20	4	1.6	1.6	ND	4.4	3
Nitrate	mg/L as N						ND	1	-	-	-	ND	ND	ND	ND	2
Nitrate + Nitrite	mg/L as N						0.80	0.13	ND	3.4	4	0.12	0.07	ND	0.56	5
Nitrogen, Total Kjeldahl (TKN)	mg/L						0.25	0.25	0.25	1.1	2	0.53	0.46	ND	1.90	6
Orthophosphate, Dissolved	mg/L as P						0.29	0.30	ND	0.62	2	0.141	0.036	ND	0.77	6
pH	pH units						8.0	7.9	7.1	8.8	3	8.3	8.5	7.1	8.8	6
Phosphorus, Total	mg/L as P						0.26	0.16	ND	0.85	3	0.070	0.050	ND	0.20	5
Sodium	mg/L						14	14	12	17	1	8.0	8.0	7.7	8.3	2
Specific conductivity	µS/cm						171	165	21	332	3	190	146	20	481	6
Temperature	°C						21	20	15	29	2	17	16	9	26	6
Total dissolved solids (TDS)	mg/L						118	101	21	226	3	124	167	14	312	4
Total organic carbon (TOC)	mg/L						4.4	4.2	1.1	8.3	4	3.0	2.4	1.0	6.8	1
Total Suspended Solids	mg/L						83	28	ND	286	3	13	13	ND	33	1
Turbidity	NTU						50	11	1.2	245	4	5.7	4.4	1.3	13	1

Table 4.9-11: Project Subarea Surface Water Quality Data Summary 2002 to 2012

Water Quality Parameters	Units	Western					Central					Eastern				
		Avg	Median	Min	Max	N[a]	Avg	Median	Min	Max	N[a]	Avg	Median	Min	Max	N[a]
Metals[b]																
Arsenic, Total	µg/L						4.5	4.0	ND	8.3	3	1.6	1.6	1.1	2.2	1
Cadmium, Dissolved	µg/L						ND	ND	ND	ND	3	ND	ND	ND	0.10	1
Cadmium, Total	µg/L						ND	ND	ND	0.14	2	ND	-	-	-	1
Copper, Dissolved	µg/L						3.6	4.2	ND	9.9	3	6.5	3.2	1.7	18.3	1
Copper, Total	µg/L						7.0	5.8	4.1	20.3	2	6.9	6.2	2.9	13.8	1
Iron, Total	µg/L						-	-	-	-	-	203	203	172	220	2
Lead, Dissolved	µg/L						ND	ND	ND	ND	3	0.24	ND	ND	0.80	1
Lead, Total	µg/L						0.7	0.7	0.4	0.9	2	1.3	0.68	0.37	4.2	1
Manganese, Total	µg/L						-	-	-	-	-	45	45	44	46	2
Molybdenum, Total	µg/L						5.2	4.5	ND	8.9	2	1.3	ND	ND	3.9	1
Nickel, Dissolved	µg/L						0.9	0.9	ND	3.1	3	ND	ND	ND	1.6	1
Nickel, Total	µg/L						1.1	1.2	1.1	2.8	2	ND	1.0	ND	1.5	1
Selenium, Total	µg/L						ND	ND	ND	ND	3	ND	-	-	-	1
Zinc, Dissolved	µg/L						ND	ND	ND	ND	3	ND	ND	ND	11	1
Zinc, Total	µg/L						10.6	10.9	ND	18.3	2	13	ND	ND	24	1
Microbial Indicators																
Coliform, Fecal	MPN/100 mL						372	290	22	1,700	2	496	26	2	4,765	5
Coliform, Total	MPN/100 mL						2,013	2,310	300	5,450	2	2,059	180	8	26,250	5
E. Coli	MPN/100 mL						334	255	8	1,760	2	189	17	2	1,253	5

Table 4.9-11: Project Subarea Surface Water Quality Data Summary 2002 to 2012

Water Quality Parameters	Units	Western					Central					Eastern				
		Avg	Median	Min	Max	N[(a)]	Avg	Median	Min	Max	N[(a)]	Avg	Median	Min	Max	N[(a)]
Other Water Quality Parameters																
Boron	µg/L						62	63	ND	156	3	4.8	0.75	ND	27	3

Source: Appendix S-1, 2015 FEIR (SWAMP and ILRP monitoring data available from CEDEN database [SWRCB 2012]; KCWA 2011b, 2012, 2013, 2014)
Notes:
Statistics are calculated based on the composite historical results for each monitoring location, e.g., AVERAGE (average alkalinity for Station No. 1, average alkalinity for Station No. 2, etc.), MIN (minimum alkalinity for Station No. 1, minimum alkalinity for Station No. 2), etc.
For calculating statistics, ND is assumed to equal 1/2 reporting limit if known or zero if unknown. Blank cells indicate data is not available.
(a) N is the number of monitoring stations on rivers or creeks in this geographic sub-area that have information on the indicated water quality parameter. In cases where N = 1, the average, median, minimum, and maximum are based on the historic results for the site from multiple sampling events. If N = 1 and there has been only one sampling event at the site, the (single) result is shown in place of the average (with no value for median, min, or max).
(b) Metals concentrations for Kern River reported by KCWA (2011b, 2012, 2013, 2014) are assumed to be dissolved metals except arsenic is assumed to be total arsenic (site located in Central Groundwater Basin sub-area).
Key:
°C = degrees Celsius
ILRP = Irrigated Lands Regulatory Program
mg/L = milligrams per liter
mL = milliliter
MPN = Most Probable Number
NTU =
SWAMP = Surface Water Ambient Monitoring Program
µg/L = micrograms per liter
µS/cm = microSiemens per centimeter

Table 4.9-12: Project Subarea Surface Water Quality Data Summary 1951-1991

Water Quality Parameters	Units	Western					Central					Eastern				
		Avg	Median	Min	Max	N(a)	Avg	Median	Min	Max	Na	Avg	Median	Min	Max	N(a)
General Water Quality																
Alkalinity, Total	mg/L as $CaCO^3$	190	192	99	305	8	139	-	-	-	1	151	123	29	523	12
Ammonia, Total	mg/L as N	0.12	0.0	0.0	0.99	2	-	-	-	-		0.0004	0.0002	0.0	0.00 1	3
Calcium	mg/L	339	469	14	591	8	45	-	-	-	1	46	26	0.0	288	11
Chloride	mg/L	226	108	38	922	9	229	-	-	-	1	76	41	2.0	382	11
Dissolved oxygen	mg/L	0.2	0.2	0.1	0.4	2	-	-	-	-	-	-	-	-	-	-
Hardness	as 3	1282	1620	59	3590	9	135	-	-	-	1	198	92	24	1102	11
Magnesium, Total	mg/L	136	80	4.4	589	8	5.7	-	-	-	1	18	6.0	1.0	115	11
Nitrate	mg/L as N	4.2	1.3	0.2	21	8	0.1	-	-	-	1	0.62	0.23	0.0	3.6	11
Nitrate + Nitrite	mg/L as N	-	-	-	-	-	-	-	-	-	-	0.16	0.17	0.01	0.47	5
Nitrogen, Total Kjeldahl	mg/L	0.19	0.17	0.10	0.38	2	-	-	-	-	-	0.38	0.30	0.21	0.60	3
Orthophosphate, Dissolved	mg/L as P	0.007	0.005	0.002	0.018	2	-	-	-	-	-	0.04	0.03	0.0	0.13	5
pH	pH units	7.2	7.1	6.7	7.8	9	8.3	-	-	-	1	7.7	7.7	7.0	8.4	12
Phosphorus, Total	mg/L as P	5.4	0.1	0.0	22	2	-	-	-	-	-	0.10	0.05	0.02	0.27	5
Sodium	mg/L	519	422	96	1170	8	96	-	-	-	1	84	28	6.3	365	11
Specific conductivity	µS/cm	3923	3875	628	8320	8	1050	-	-	-	1	665	368	81	2652	12
Temperature	°C	6.1	6.2	-0.6	12.9	2	-	-	-	-	-	16	16	3.0	26	9
Total dissolved solids	mg/L	49	43	10	108	2	-	-	-	-	-	-	-	-	-	-
Turbidity	NTU	5.2	2.6	1.0	22	2	-	-	-	-	-	-	-	-	-	-

Table 4.9-12: Project Subarea Surface Water Quality Data Summary 1951-1991

Water Quality Parameters	Units	Western					Central					Eastern				
		Avg	Median	Min	Max	N[(a)]	Avg	Median	Min	Max	N[a]	Avg	Median	Min	Max	N[(a)]
Metals[(b)]																
Arsenic, Dissolved	µg/L	-	-	-	-	-	*(no metals data available from EPA STORET for rivers and creeks in this sub-area)*					5.0	0.0	0.0	16	1
Arsenic, Total	µg/L	2.9	2.5	0.0	6.8	3						-	-	-	-	-
Cadmium, Dissolved	µg/L	-	-	-	-	-						0.0	0.0	0.0	0.0	1
Cadmium, Total	µg/L	0.49	0.49	0.34	0.73	2						-	-	-	-	-
Copper, Dissolved	µg/L	-	-	-	-	-						0.9	0.0	0.0	5.0	1
Copper, Total	µg/L	1.4	0.85	0.29	4.7	2						0.0	1	-	-	-
Iron, Dissolved	µg/L	-	-	-	-	-						34	20	0.0	90	1
Iron, Total	µg/L	126	160	0.0	274	3						335	335	331	340	1
Lead, Dissolved	µg/L	-	-	-	-	-						0.0	0.0	0.0	0.0	1
Lead, Total	µg/L	0.33	0.39	0.0	0.73	3						-	-	-	-	-
Manganese, Dissolved	µg/L	-	-	-	-	-						6.0	5.0	0.0	16	1
Selenium, Total	µg/L	-	-	-	-	-						6.0	0.0	0.0	20	1
Zinc, Dissolved	µg/L	-	-	-	-	-						3.3	0.0	0.0	15	1
Zinc, Total	µg/L	-	-	-	-	-						10	-	-	-	1

Table 4.9-12: Project Subarea Surface Water Quality Data Summary 1951-1991

Water Quality Parameters	Units	Western					Central					Eastern				
		Avg	Median	Min	Max	N[(a)]	Avg	Median	Min	Max	N[a]	Avg	Median	Min	Max	N[(a)]
Other Water Quality Parameters																
Boron	µg/L	1500	1600	400	3200	8	900	-	-	-	1	404	200	0.0	1560	11

Source: Appendix S-1, 2015 FEIR (EPA STORET Legacy Data Center [for data before January 1, 1999])
Notes:
Statistics are calculated based on the composite historical results for each monitoring location, e.g., average alkalinity for Station No. 1, average alkalinity for Station No. 2, etc.), MIN (minimum alkalinity for Station No. 1, minimum alkalinity for Station No. 2, etc.).
Values of "0.0" are as shown in the data source and likely indicate ND. Blank cells indicate data is not available.
(a) N is the number of monitoring stations on rivers or creeks in this geographic sub-area that have information on the indicated water quality parameter. In cases where N = 1, the average, median, minimum, and maximum are based on the historic results for the site from multiple sampling events. If N = 1 and there has been only one sampling event at the site, the (single) result is shown in place of the average (with no value for median, min, or max).
Key:
°C = degrees Celsius
µg/L = micrograms per liter
µS/cm = microSiemens per centimeter
a^3 = hardness
EPA STORET = U.S. Environmental Protection Agency storage and retrieval
mg/L = milligrams per liter
mL = milliliter
ND = non-detect
NTU = nephelometric turbidity units
N = nitrogen
P =Phosphorus

Table 4.9-13: Central Valley Project Water Quality in Friant-Kern Canal and Kern River Water Quality near Bakersfield, CA, 2010-2013

Water Quality Parameters	Units	Friant-Kern Canal, 2010 – 2013[a]					Kern River, 2010 – 2013[a]				
		Avg	Median	Min[b]	Max[c]	N[d]	Avg	Median	Min[b]	Max[c]	N[d]
General Water Quality											
Alkalinity, Total	mg/L as $CaCO_3$	49	45	20	83	4	61	63	57	64	4
Ammonia	mg/L as N	ND	-	-	-	4	0.019	0.012	ND	0.050	4
Bicarbonate	mg/L	56	47	25	99	4	75	76	69	78	4
Calcium	mg/L	17	13	4.9	34	4	14	15	13	16	4
Carbonate	mg/L	3.0	ND	ND	10	4	ND	-	-	-	4
Chloride	mg/L	25	16	2.2	61	4	5.0	5.1	3.5	6.4	4
Color	Units	17	15	11	24	4	21	20	16	29	4
Hardness, Total	mg/L as	51	46	13	94	4	47	48	42	51	4
Magnesium	mg/L	2.2	1.5	0.16	5.1	4	2.7	2.7	2.5	3.0	4
Nitrate + Nitrite	mg/L as N	0.66	0.31	ND	1.8	4	ND	-	-	-	4
Nitrate	mg/L as N	0.7	0.3	ND	1.8	4	ND	-	-	-	4
Nitrite	mg/L as N	ND	-	-	-	4	ND	-	-	-	4
pH	Units	8.1	8.0	7.6	8.9	4	7.9	7.9	7.8	7.9	4
Phosphate	mg/L	ND	-	-	-	4	ND	-	-	-	4
Potassium	mg/L	1.3	1.2	1.1	3.0	4	1.9	1.9	1.8	12.0	4
Sodium	mg/L	20	15	4.5	2.8	4	14	14	12	17	4
Specific Conductance	µS/cm	213	198	54	227	4	169	165	156	189	4
Sulfate	mg/L	16	14	1.3	34	4	13	13	8.5	18	4
Total Dissolved Solids	mg/L	129	122	40	393	4	102	101	96	109	4
Total Organic Carbon	mg/L	2.0	2.3	0.72	41	4	2.6	2.5	2.1	3.3	4
Turbidity	NTU	1.6	1.4	0.56	1.7	4	6.1	6.4	3.4	8.4	4

Table 4.9-13: Central Valley Project Water Quality in Friant-Kern Canal and Kern River Water Quality near Bakersfield, CA, 2010-2013

Water Quality Parameters	Units	Friant-Kern Canal, 2010 – 2013[a]					Kern River, 2010 – 2013[a]				
		Avg	Median	Min[b]	Max[c]	N[d]	Avg	Median	Min[b]	Max[c]	N[d]
Metals											
Aluminum	µg/L	ND	91	10	160	4	335	299	235	485	4
Antimony	µg/L	87	-	-	-	4	ND	-	-	-	4
Arsenic	µg/L	1.0	ND	ND	3.4	4	3.8	4.0	3.2	4.0	4
Barium	µg/L	ND	-	-	-	4	ND	-	-	-	4
Beryllium	µg/L	ND	-	-	-	4	ND	-	-	-	4
Cadmium	µg/L	ND	-	-	-	4	ND	-	-	-	4
Chromium	µg/L	0.25	ND	ND	0.85	4	0.25	ND	ND	0.85	4
Chromium (Hexavalent)	µg/L	0.25	ND	ND	0.85	4	ND	-	-	-	4
Copper	µg/L	ND	-	-	-	4	ND	-	-	-	4
Iron	µg/L	79	69	ND	172	4	436	408	208	701	4
Lead	µg/L	ND	-	-	-	4	ND	-	-	-	4
Manganese	µg/L	ND	-	-	-	4	37	38	33	41	4
Mercury	µg/L	ND	-	-	-	4	ND	-	-	-	4
Nickel	µg/L	ND	-	-	-	4	ND	-	-	-	4
Selenium	µg/L	ND	-	-	-	4	ND	-	-	-	4
Silver	µg/L	ND	-	-	-	4	ND	-	-	-	4
Thallium	µg/L	ND	-	-	-	4	ND	-	-	-	4
Zinc	µg/L	ND	-	-	-	4	ND	-	-	-	4
Other Water Quality Parameters											
Asbestos	MFL	ND	-	-	-	4	ND	-	-	-	4
Boron	mg/L	0.078	0.075	ND	0.16	4	0.11	0.13	0.02	0.16	4
Bromide	mg/L	0.088	0.055	ND	0.22	4	0.013	0.015	0.0015	0.020	4
Cyanide	mg/L	ND	-	-	-	4	ND	-	-	-	4
Fluoride	mg/L	0.10	0.08	ND	0.21	4	.24	0.24	0.21	0.28	4
Foaming Agents	mg/L	ND	-	-	-	4	0	-	-	-	4
Methyl tert-butyl ether	mg/L	ND	-	-	-	4	ND	-	-	-	4

Table 4.9-13: Central Valley Project Water Quality in Friant-Kern Canal and Kern River Water Quality near Bakersfield, CA, 2010-2013

Water Quality Parameters	Units	Friant-Kern Canal, 2010 – 2013[(a)]					Kern River, 2010 – 2013[(a)]				
		Avg	Median	Min[(b)]	Max[(c)]	N[(d)]	Avg	Median	Min[(b)]	Max[(c)]	N[(d)]
Odor	Units	5.3	6.0	3.5	6.0	4	ND	5.0	3.2	6.0	4
Perchlorate	mg/L	ND	-	-	-	4	4.8	-	-	-	4
Silica	mg/L	15	15	12	19	4	ND	5.7	4.2	16	4
Thiobencarb	mg/L	ND	-	-	-	4	8.2	-	-	-	4
Unregulated Volatile Organics[e]	mg/L	ND	-	-	-	4	ND	-	-	-	4
Unregulated Non-Volatile Synthetic Organics[f]	mg/L	ND	-	-	-	4	ND	-	-	-	4
Gross Alpha	pCi/L	0.91	ND	ND	3.1	4	ND	ND	ND	2.0	4
Gross Beta	mrem/yr	ND	-	-	-	4	0.60	-	-	-	4
Radium 226	pCi/L	0.36	ND	ND	12	4	ND	ND	ND	0.88	4
Radium 226 + Radium 228	pCi/L	ND	-	-	-	4	0.26	-	-	-	4
Radium 228	pCi/L	ND	-	-	-	4	0.46	ND	ND	1.5	4
Strontium-90	pCi/L	ND	-	-	-	4	ND	-	-	-	4
Tritium	pCi/L	ND	-	-	-	4	ND	-	-	-	4
Uranium	pCi/L	0.77	ND	ND	2.6	4	1.6	1.5	1.5	1.9	4

Table 4.9-13: Central Valley Project Water Quality in Friant-Kern Canal and Kern River Water Quality near Bakersfield, CA, 2010-2013

Water Quality Parameters	Units	Friant-Kern Canal, 2010 – 2013[(a)]					Kern River, 2010 – 2013[(a)]				
		Avg	Median	Min[(b)]	Max[(c)]	N[(d)]	Avg	Median	Min[(b)]	Max[(c)]	N[(d)]
SDWA Regulated Constituents[g]											
Regulated Volatile Organics[h]	mg/L	ND	-	-	-	4	ND	-	-	-	4
Regulated Non-Volatile Synthetic Organics[i]	mg/L	ND	-	-	-	4	ND	-	-	-	4

Sources: Appendix S-1, 2015 FEIR from KCWA 2011b, 2012, 2013, 2014

Notes:

(a) Statistics calculated based on four years of reported data. Where "ND", average, median, minimum, and maximum assume a concentration of zero (no reporting limit provided by data source).

(b) Minimum values calculated as 5th percentile. When one or more result is ND, the minimum is reported as ND.

(c) Maximum values calculate as 95th percentile.

(d) N = 4 based on four reports (KCWA 2011b; 2012; 2013; 2014) that each reported a single value for each parameter. The reports did not indicate whether the result was based on multiple measurements.

(e) 35 compounds were measured and were not detected. Complete list available from KCWA (2011b; 2012; 2013; 2014).

(f) 20 compounds were measured and were not detected. Complete list available from KCWA (2011b; 2012; 2013; 2014).

(g) Some parameters listed under above categories are also regulated by the SDWA.

(h) 27 compounds were measured and were not detected. Complete list available from KCWA (2011b; 2012; 2013; 2014). (i) 33 compounds were measured and were not detected. Complete list available from KCWA (2011b; 2012; 2013; 2014).

Key:
µg/L = micrograms per liter
µS/cm = microSiemens per centimeter
EPA STORET = U.S. Environmental Protection Agency storage and retrieval
MFL = million fibers per liter
mg/L = milligrams per liter
mrem/yr = health effect of ionizing radiation per year
ND = not detected
NTU = nephelometric turbidity units
P = Phosphorus
pCi/L = picocuries per liter
SDWA = Safe Drinking Water Act

Table 4.9-14: State Water Project Water Quality in California Aqueduct at Kettleman City, California, 2004 to 2014

Water Quality Parameters	Units	Station Code: KA017226/Kettleman CK-21				
		Average	**Median**	**Min[(a)]**	**Max[(b)]**	**N**
General Water Quality						
Alkalinity, Total	mg/L as $CaCO_3$	72	73	47	90	127
Ammonium	mg/L as N	0.016	0.010	ND	0.040	118
Calcium	mg/L	19	19	13	27	121
Chloride	mg/L	72	74	27	114	123
Dissolved Organic Carbon	mg/L	3.4	3.1	2.2	5.6	122
Dissolved oxygen (field)	mg/L	9.3	9.3	7.3	11.6	121
Hardness	mg/L as $CaCO_3$	99	101	60	140	121
Magnesium	mg/L	12	13	7	18	121
Nitrate + Nitrite	mg/L as N	0.57	0.51	0.09	1.30	121
Nitrate	mg/L as N	0.56	0.53	0.11	1.26	123
Nitrogen, Total Kjeldahl	mg/L as N	0.37	0.40	0.200	0.70	118
Orthophosphate, Dissolved	mg/L as P	0.067	0.060	0.05	0.100	121
pH (field)	pH units	NA	7.8	7.0	8.4	123
Phosphorus, Total	mg/L as P	0.092	0.090	0.060	0.14	118
Sodium	mg/L	51	52	23	76	121
Specific Conductivity	μS/cm	455	477	244	623	124
Sulfate	mg/L	36	35	9	61	123
Temperature (field)	°C	18	17	1	25	123
Total dissolved solids (TDS)	mg/L	257	272	9.5	361	127
Total organic carbon	mg/L	3.6	3.3	142	6.1	192
Total suspended solids	mg/L	5.0	4.0	2.3	15.0	128
Turbidity (field)	NTU	5.4	3.9	ND	13	123
Metals						
Aluminum, Total	μg/L	104	87	24	248	33
Antimony, Dissolved	μg/L	ND	-	-	-	118
Antimony, Total	μg/L	ND	-	-	-	33
Arsenic, Dissolved	μg/L	2.1	2.0	ND	3.0	121
Arsenic, Total	μg/L	2.0	2.0	ND	3.0	33

Table 4.9-14: State Water Project Water Quality in California Aqueduct at Kettleman City, California, 2004 to 2014

Water Quality Parameters	Units	Station Code: KA017226/Kettleman CK-21				
		Average	Median	Min[a]	Max[b]	N
Barium, Total	µg/L	30	29	25	39	33
Beryllium, Dissolved	µg/L	ND	-	-	-	118
Beryllium, Total	µg/L	ND	-	-	-	33
Cadmium, Total	µg/L	ND	-	-	-	33
Chromium, Dissolved	µg/L	1.1	ND	ND	3.0	121
Chromium, Total	µg/L	ND	-	-	-	33
Copper, Dissolved	µg/L	1.6	2.0	ND	2.0	121
Copper, Total	µg/L	1.7	2.0	ND	2.0	33
Iron, Dissolved	µg/L	9.7	ND	ND	30	121
Iron, Total	µg/L	153	122	32	382	33
Lead, Dissolved	µg/L	ND	-	-	-	121
Lead, Total	µg/L	ND	-	-	-	33
Manganese, Dissolved	µg/L	ND	ND	ND	5.0	121
Manganese, Total	µg/L	20	16	6	49	33
Nickel, Dissolved	µg/L	1.1	ND	ND	2.0	118
Nickel, Total	µg/L	1.6	2.0	1.0	2.0	33
Selenium, Dissolved	µg/L	ND	ND	ND	2.0	122
Selenium, Total	µg/L	ND	ND	ND	2.0	33
Silver, Total	µg/L	ND	-	-	-	33
Zinc, Dissolved	µg/L	ND	-	-	-	121
Zinc, Total	µg/L	ND	ND	ND	8.2	33
Other Water Quality Parameters						
Boron	mg/L	0.16	0.20	0.05	0.30	121
Bromide	mg/L	0.23	0.22	00.07	0.40	123
Fluoride	L	ND	-	-	-	48
SDWA Regulated Constituents[c]						
Primary drinking water standards						
Disinfection Byproducts (DBPs) [d]	µg/L	ND	-	-	-	30
Organics[e]	µg/L	ND	-	-	-	30

Table 4.9-14: State Water Project Water Quality in California Aqueduct at Kettleman City, California, 2004 to 2014

Water Quality Parameters	Units	Station Code: KA017226/Kettleman CK-21				
		Average	Median	Min(a)	Max(b)	N
2,4-D	µg/L	ND	ND	ND	0.16	30
Simazine	µg/L	0.029	ND	ND	0.097	30

Source: 2015 FEIR Appendix S-1 from DWR 2014
Notes:
(a) Minimum value calculated as the 5th percentile. When one or more result is ND, the minimum is reported as ND.
(b) Maximum value calculated as the 95th percentile.
(c) Some parameters listed under General Water Quality and Metals are regulated by the SDWA.
(d) Trihalomethanes only.
(e) Results from regulated organics were below reporting limit except 2,4-D and Simazine.
Where "ND", average, median, minimum, and maximum are calculated assuming a value equal to one-half the reporting limit.
Key:
°C = degrees Celsius
µg/L = micrograms per liter
µS/cm = microSiemens per centimeter
L = liter
mg/L = milligrams per liter
N = number of results
NA = not applicable
ND = not detected above the method reporting limit
NTU = nephelometric turbidity units
SDWA = Safe Drinking Water Act

As discussed in Section 4.9.3, Regulatory Setting, to address chronic water supply concerns in arid portions of the country, regulations adopted under the federal CWA allow produced water that meets specified criteria to be used for agricultural or wildlife propagation purposes in onshore locations west of the 98th meridian (which extends through central Texas, Oklahoma, Nebraska, Kansas, and North and South Dakota east of the Rocky Mountains). In 2007, the CVRWQCB issued WDRs for the delivery and blending of treated produced water to the CWD in the eastern project Subarea for agricultural irrigation. The 2007 WDRs allowed for the discharge of the blended and treated produced water into certain canals and reservoirs regulated by the CVRWQCB and also for discharge into the Poso Creek system when supplies exceeded irrigation demand. In 2011, the CVRWQCB determined that the blended produced water discharges into the Poso Creek system exceeded applicable WDR arsenic concentration limits (CVRWQCB 2011). In response, discharges of blended produced water to the Poso Creek system were eliminated by routing any excess supplies by pipeline to percolation ponds managed by the Famoso Groundwater Banking Project. In 2012, the CVRWQCB issued revised WDRs for the use of the Famoso facilities and determined that arsenic in the blended produced water would be retained in the soil surfaces of the percolation facility, and would not change or degrade groundwater quality (CVRWQCB 2012).

In 1998, the CVRWQCB prepared WDRs Order R5-1998-205, including a for an operator in the Jasmin Field. The WDRs/Monitoring and Reporting Program provides regulatory oversight for the operator to reuse good quality produced water (not exceeding Basin Plan limitations) for local agriculture applications. The reuse blends the produced water with other surface and/or groundwater for distribution by the Jasmin Ranchos Mutual Water District.

Produced water is not currently used for agriculture or wildlife propagation in the Western or *most of the* Central portions of the Project Area. The KTWD is located near the California Highway 65 and the intersection of State Route 155 within the Eastern Subarea. The KTWD completed an environmental impact report (EIR), including an addendum in 2019, for a proposed modified project that would deliver produced water to existing crops within the District (SCH Number: 2015021024) (CEQA 2015). Additional use of treated produced water has been considered, but has not yet been formally proposed, in other Project Area locations, partially in response to the prolonged drought that affected California and other portions of the western United States. Produced water is reused in the Jasmin Field and by CWD under WDRs issued by the CVRWQCB. *As of October 2020, the CVRWQCB has issued the following WDRs for produced water use for agriculture: California Resources Production Corporation, Order No. R5-2006-0050; Chevron USA and Cawelo Water District Order No. R5-2012-0058 and Revised Monitoring and Reporting Program (MRP) Order No. R5-2012-0058; Valley Water Management Company and Cawelo Water District Order No. R5-2012-0059; Hathaway, LLC and Jasmin Mutual Water District Order No. 98-205; and California Resources Production Corporation and North Kern Water Storage District Order No. R5-2015-0127, Revised MRP Order No. R5-2015-0127 and Order No. R5-2016-0093: Amendment to Waste Discharge Requirements Order No. R5-2015-0127; and E&B Natural Resources, Order No. R5-2019-0024 (California Water Boards, Central Valley 2020).* Additional information concerning produced water reuse for SGMA purposes in provided in the discussion of KCS GSPs and management area plans and SGMA Projects above. *Additional information concerning the regulation, monitoring and continued scientific investigation of produced water reuse for agriculture and food safety is provided in Section 4.9.3, Regulatory Setting, Produced Water Reuse for Agricultural Irrigation.*

Well installation, drilling and related construction activities can result in the discharge of drilling mud and fluids to land surfaces around and adjacent to a well if the construction does not utilize a closed-loop system that captures and recirculates muds and fluids in portable storage tanks. Drilling muds and fluids in other construction operations are typically impounded in unlined, shallow ponds constructed adjacent to a well. Several constituents are used during the drilling process for lubrication, well stability, and mud evacuation, among other purposes. Table 4.9-15 lists the common chemicals used in Project Area oil and during gas well drilling operations.

Table 4.9-15: Chemicals Commonly Used in Drilling Fluid in Project Area

Ingredients[a]	
Water	Marble White
Asphsol Supreme	MDC
Barite	MI Gel
Calcium Carbonates	MI Water
CF Desco II	Mix II F, M, C
Citric Acid	PolyPac

Table 4.9-15: Chemicals Commonly Used in Drilling Fluid in Project Area

Ingredients[a]	
CleanFaze	PolyPlus
Cottonseed Hulls and Pellets	PolySwell
Defoam X and A	Potassium Chloride
DrilZone L	PowerVis
D-Solver	PrimaSeal
DualFlo	SafeCarb
DuoVis	SAPP
FloVis Plus	Sawdust
Gelex	Soda Ash
Gelite	Sodium Bicarbonate
G-Seal Plus	Sodium Chloride
KlaStop	SP-101
Kwik-Seal	Tannathin
Lime	ThruTrol
MagmaFiber	VinSeal
MagOx	Walnut Shell
	WellZyme A

Source: Appendix S-1, 2015 FEIR
Note:
[a] As reported by Chevron USA

For several years, the CVRWQCB included oil and gas well drilling discharges as one of several Project Area activities that were considered to pose a low threat to water quality and for which requirements to file a report of waste discharge were waived. In 2013, the CVRWQCB declined to extend the waiver for the discharge of oil and gas-related drilling muds and fluids (CVRWQCB 2013b). In response, oil and gas well construction in the Project Area either utilize closed-loop systems that avoid any discharge of drilling muds and fluids, or obtain regulatory coverage under SWRCB General Order 2003-0003-DWQ, which addresses low-threat discharges to land (SWRCB 2003). The SWRCB maintains a list of Project Area and other oil and gas operators enrolled under General Order 2003-0003-DWQ (SWRCB 2003). CalGEM maintains online copies of the California Environmental Quality Act (CEQA) documentation for oil and gas well permits approved since 2010 that include closed loop drilling systems for several well construction projects in the Project Area (DOGGR 2015b).

Additional information on surface water quality and oil and gas activities is provided above for each of the KCS GSPs and management area plans in the Project Area.

Storm Water Discharge and NPDES Permitting

The SWRCB has adopted a statewide General National Pollutant Discharge Elimination System (NPDES) Permit for Storm Water Discharges Associated with Construction and Land Disturbance Activities (the General Construction General Permit) (WQ Order No. 2009-0009–DWQ, as modified by 2010-0014-DWQ and 2012-006-DWQ) and a statewide General NPDES Permit for Storm Water Discharges Associated with Industrial Activities (Industrial General Permit) (Order 97-03-DWQ, expiring June 30, 2015, and Order 2014-0057-DWQ [effective July 1, 2015]). Where applicable, the Construction General Permit and the Industrial General Permit require the preparation of a stormwater pollution prevention plan, the implementation of BMPs, and other monitoring and management measures to reduce water quality impacts that could result from discharges of contaminated stormwater from the covered activities. Oil and gas exploration, construction, and operational activities are subject to these general permits, with some exceptions as discussed below.

Under the CWA, stormwater runoff from oil and gas operations is exempt from the NPDES permitting requirements so long as (1) it is composed entirely of “flows which are from conveyances or systems of conveyances” (e.g., pipes, conduits, ditches, and channels) used for the collection of runoff; and (2) it is not contaminated by and has not come into contact with “any overburden, raw material, intermediate products, finished product, byproduct, or waste products located on the site of such operations” per CWA Section 402(*l*)(2). As a result of legislative and regulatory developments and related legal challenges over the past 10 years (described in Section 4.9.3, Regulatory Setting), the EPA interprets this exemption to apply only if there have been no reportable discharges of hazardous substances or of harmful quantities of oil from the facility; and the runoff does not contribute to a violation of a water quality standard, as determined through the application of best available technology. Based on these highly restrictive conditions for exemption, most construction-related stormwater discharges from oil and gas construction sites that are 1 acre or more in size are subject to the Construction General Permit. Sites that are very small (less than 1 acre in size and not part of a “common plan” disturbing more than 1 acre) and that are determined to have no potential to contribute to a water quality standards violation are exempt from the Construction General Permit. None of these exemptions is self-executing, meaning that a discharger in the Project Area must obtain a waiver or exemption from the CVRWQCB. The SWRCB summarizes stormwater construction activity associated with oil and gas exploration online (SWRCB 2015a). An EPA Fact Sheet addressing permitting requirements for oil and gas stormwater discharges is available online (EPA 2009).

Oil and gas production and exploration coverage under and compliance with the Construction General Permit varies significantly by individual operator and facility throughout the Project Area, depending on the size and nature of the construction activity and the physical setting of each site, including its proximity and hydrologic connection to waters of the United States). CalGEM maintains online copies of the CEQA documentation for several oil and gas well permits approved since 2010 showing that several permitted activities in the Project Area were considered to be exempt or subject to waiver from some or all of the Construction General Permit requirements (DOGGR 2015b). Updates to the state Construction General Permit are discussed in Section 4.9.3, Regulatory Setting.

Oil and gas operations are considered industrial activities and are subject to the Industrial General Permit. In appropriate circumstances, an operator may apply reduce or avoid compliance requirements by filing and certifying a notice of non-applicability (NONA) supported by No Discharge Technical Report prepared by a state-licensed engineer. Oil and gas facilities may qualify for a NONA if they are (1) engineered and constructed to contain the maximum historic precipitation event (or series of events) so that there will be no discharge of industrial stormwater to waters of the United States; or (2) located in basins or other physical locations that are not hydrologically connected to waters of the United States. As discussed in the 2015 FEIR Section 4.4, Biological Resources, the regulatory definition of "waters of the United States," in general, and the delineation of any such waters in the Project Area under the existing and proposed new rules, is also subject to significant and ongoing legal uncertainty. As a result, the extent to which oil and gas production and exploration activities in the Project Area must obtain coverage under and comply with the Industrial General Permit continues to evolve. Updates to the Industrial General Permit are discussed in Section 4.9.3, Regulatory Setting.

Groundwater Quality Data

Groundwater quality data for the Project Area and each Subarea was obtained by utilizing the most recent legislatively mandated study (SWRCB 2013) of impaired drinking water wells maintained by the California Department of Public Health, summaries of two Groundwater Ambient Monitoring and Assessment (GAMA) well water quality research reports prepared by the USGS (Shelton et al. 2008; Burton et al. 2012), and an analysis of available online water quality sampling results for shallower and deeper wells in the Project Area from 2007 through 2012. As discussed above, a generally impermeable clay layer located primarily in the Western and Central Subareas physically divides many Project Area groundwater resources from deeper oil-bearing reservoirs. According to the California Water Plan Update 2013 (DWR 2013), human activities have generally not affected water quality in the deeper San Joaquin valley aquifers, including groundwater located under the regional clay layer. Evidence of anthropogenically related constituents is more likely to be detected in shallower groundwater zones throughout the valley and above the clay layer.

Oil and gas activity groundwater impacts were analyzed in a 1989 CalGEM (then DOGGR) study, which concluded that many constituents know to occur in oil field produced water and other wastes, such as carbonates, bicarbonates, hydroxides, borates, silicates, phosphates, and organic substances, are also associated with municipal sewage and many industrial wastes. Groundwater quality in the Project Area has been affected by the use of imported water, overdraft, and soil salt that increase net TDS loads to surface soils, present and past climate conditions, and by the rocks and sediments that come into contact with water. The CalGEM report noted that produced oil field water seldom contains significant or detectable amounts of ammonia, nitrate, heavy metals or phosphate, while agricultural activity, including the application of fertilizers and pesticides, do not generally contain high amounts of boron or chloride. Consequently, elevated boron or chloride levels could indicate oil and gas production and exploration activity impacts to groundwater. However, the study also found that these constituents were detected in high concentrations in locations where no historical groundwater injection or production has occurred (Mitchell 1989).

As a result, the analysis concluded that elevated boron and chloride can occur in Kern County from sources other than oil and gas production and exploration activities.

The federal secondary MCL for chloride is 250 mg/L. Secondary MCLs are based on consumer acceptance and are not enforced by the federal government. No primary or secondary MCL has been established for boron. The California Department of Public Health has adopted health-based advisory notification levels for chemicals in drinking water that are not subject to an MCL. The notification level for boron is 1,000 micrograms per liter or 1 mg/L.

CWC Section 10782 required the SWRCB to prepare and submit a report to the California legislature identifying communities that rely on contaminated groundwater as a primary source of drinking water. The SWRCB completed the report in January 2013, which included an analysis of wells within the Project Area that did not meet at least one drinking water MCL on two occasions during 2002 through 2010 (SWRCB 2013). Appendix S-1 in the 2015 FEIR, Table 3-10 summarizes the results of the study for wells in the Project Area. As noted by the SWRCB in the report, over 98% of Californians served by public water suppliers are provided with safe drinking water. Although many water suppliers draw from contaminated groundwater sources, most are able to treat or blend the water with cleaner supplies to meet applicable standards.

The report identified public water systems that draw from one or more contaminated groundwater wells prior to any treatment or blending. As a result, the report provides a conservative assessment of Project Area drinking water because it excludes all wells that met applicable MCLs prior to subsequent treatment or blending. As shown in Table 3-10 in Appendix S-1 of the 2015 FEIR, about 79 wells in the Project Area exceeded at least one drinking water MCL on two occasions from 2001 through 2010. The most commonly detected constituent above applicable MCLs in Project Area drinking water wells in the SWRCB study was arsenic, which occurs naturally in the regional aquifers. Radionucleatides, generally from natural sources, and nitrates and other chemicals, likely associated with agricultural activity, were also detected in several Project Area wells.

The USGS has prepared two studies of groundwater quality in the Project Area based on the results of the state GAMA program, which tests and provides water quality results for more than 200,000 wells located throughout the state. Data are reported for multiple groundwater levels, including (1) shallow wells located in regulated cleanup sites or used for private domestic water; (2) intermediate depth water supply wells; and (3) deeper wells ranging from hundreds to thousands of feet below the ground used for public water supply and agricultural irrigation. The USGS developed summaries of water quality in the Project Area by identifying about 47 wells to facilitate a randomized grid-based statistical analysis of water quality testing results generated in 2006. The locations of the wells used in the two USGS studies are shown on Figure 4.9-13.

The first USGS analysis of the well data was published in 2008 to provide a statistically valid representation of groundwater quality parameters in the Project Area (Shelton et al. 2008). Table 4.9-16 summarizes the results of the 2008 study.

Table 4.9-16: USGS GAMA Well Water Quality Data Summary

Water Quality Parameter	Units	Average	Median	Min[(a)]	Max[(b)]	N
General Water Quality						
Alkalinity, Bicarbonate	mg/L	86	84	26	144	14
Ammonia	mg/L as N	0.004	ND	ND	0.02	14
Calcium	mg/L	55	35	14	136	14
Chloride	mg/L	53	33	9	158	14
Dissolved oxygen	mg/L	3.4	3.0	0.1	8.2	14
Magnesium	mg/L	8.6	1.2	0.05	38	14
Nitrite	mg/L as N	0.05	ND	ND	0.27	14
Nitrite + Nitrate	mg/L as N	4.3	2.4	0.4	13	14
pH	pH units	8.2	8.0	7.7	9.3	14
Phosphate	mg/L as P	0.005	0.004	ND	0.01	14
Potassium	mg/L	3.0	1.8	0.5	8.3	14
Silicon	mg/L	19	20	14	23	14
Sodium	mg/L	71	42	21	180	14
Specific Conductivity	µS/cm	667	417	208	1,669	14
Sulfate	mg/L	151	42	20	649	14
Temperature	°C	23	22	18	28	14
Total Dissolved Solids	mg/L	448	250	171	1,238	14
Total Nitrogen	mg/L as N	27	17	0.4	93	14
Total Organic Carbon	mg/L	0.5	0.4	0.3	0.8	14
Metals						
Antimony	µg/L	0.2	0.2	ND	0.8	14
Arsenic	µg/L	5.5	2.3	1.3	18	14
Barium	µg/L	51	48	16	107	14
Beryllium	µg/L	0.03	ND	ND	0.2	14
Cadmium	µg/L	0.02	ND	ND	0.07	14
Chromium, Total	µg/L	1.2	1.0	0.03	3.2	14
Cobalt	µg/L	0.07	0.05	ND	0.16	14
Copper	µg/L	1.3	0.8	0.3	3.5	14
Iron, Total	µg/L	5.3	2.0	ND	16.2	14
Lead	µg/L	0.5	0.2	ND	1.6	14
Lithium	µg/L	10.6	5.0	2.5	46	14
Manganese	µg/L	5.9	0.5	ND	69	14
Molybdenum	µg/L	7.0	3.0	0.8	25	14

Table 4.9-16: USGS GAMA Well Water Quality Data Summary

Water Quality Parameter	Units	Average	Median	Min[(a)]	Max[(b)]	N
Nickel	µg/L	0.7	0.8	0.1	1.9	14
Selenium	µg/L	1.4	0.6	ND	6.7	14
Strontium	µg/L	599	391	155	2,360	14
Tungsten	µg/L	0.7	0.2	0.1	6.2	14
Uranium	µg/L	5.7	5.5	0.4	15	14
Vanadium	µg/L	11.8	6.5	1.3	53	14
Zinc	µg/L	8.4	7.5	0.9	19	14
Other Water Quality Parameters						
1,2,3-Trichloropropane	µg/L	0.03	ND	ND	0.2	14
Boron	µg/L	223	139	23	626	14
Bromide	mg/L	0.2	0.1	0.03	0.7	14
Fluoride	mg/L	0.3	0.2	0.1	0.8	14
Iodide	mg/L	0.01	0.002	ND	0.04	14
Isopropylbenzene	µg/L	ND	ND	ND	0.01	14
Radionuclides						
Gross Alpha; 72-hour Count	pCi/L	6.2	5.2	1.4	11.5	10
Gross Alpha; 30-day Count	pCi/L	2.9	1.9	0.5	7.9	10
Gross Beta; 72-hour Count	pCi/L	3.2	2.1	1.1	8.9	10
Gross Beta; 30-day Count	pCi/L	4.1	3.0	1.3	8.9	10
Radium-226	pCi/L	0.1	0.1	0.04	0.4	10
Radium-228	pCi/L	2.5	0.4	0.2	12.1	10
Radon-222	pCi/L	761	672	331	1,428	10
Uranium-234	pCi/L	2.1	1.9	0.1	4.4	14
Uranium-235	pCi/L	3.0	0.2	0.02	13.7	14
Uranium-238	pCi/L	1.7	1.6	0.1	3.9	14
SDWA Regulated Constituents						
Primary Drinking Water Standards						
Disinfection Byproducts (DBPs)	µg/L	-	-	-	-	-
Chloroform	µg/L	0.1	ND	ND	0.7	14
Organics	µg/L	-	-	-	-	-
1,2-Dichloropropane	µg/L	0.1	0.1	ND	0.4	14
Benzene	µg/L	0.01	ND	ND	0.02	14

Table 4.9-16: USGS GAMA Well Water Quality Data Summary

Water Quality Parameter	Units	Average	Median	Min[(a)]	Max[(b)]	N
Dibromochloropropane	μg/L	0.02	ND	ND	0.04	14
Tetrachloroethene	μg/L	0.04	ND	ND	0.15	14

Source: Appendix S-1, 2015 FEIR; Shelton et al. 2008
Notes:
(a) Minimum value calculated as the 5th percentile. When one or more result is ND, the minimum is reported as ND.
(b) Maximum value calculated as the 95th percentile.
(c) Some parameters listed under above categories are also regulated by the SDWA.
Where "ND", average, median, minimum, and maximum are calculated assuming a value equal to one-half the reporting limit, or equal to zero if result reported as 0.0, i.e., no detection limit provided.
Key:
°C = degrees Celsius
μg/L = micrograms per liter
μS/cm = microSiemens per centimeter
mg/L = milligrams per liter
N = number of results (reported for a subset of grid wells as defined by Shelton et al., 2008)
NA = not applicable
ND = not detected above the method reporting limit, refer to Burton and Belitz (2012)
P = phosphorus
pCi/L = picocuries per liter

The 2008 USGS study found that the detections of most inorganic constituents were below health-based thresholds. Nitrate and arsenic were detected above MCL levels in two wells, and vanadium was detected above California notification levels in one sample. The USGS found that volatile organic compounds (VOCs) and pesticides were detected in about 60% of the grid wells and that all of these detections were below health-based thresholds except for a fumigant (1,2-dibromo-3-chloropropane [DBCP]) used in agriculture detected above the applicable MCL in one sample. None of the data for the wells in the USGS study reported chloride above the secondary MCL level (250 mg/L) or boron in concentrations above the state notifications level (1 mg/L). A second analysis of the Project Area well grid data was published by the USGS in 2012 and compared the concentration distributions for individual water quality parameters with applicable federal and state regulatory MCL thresholds for protecting human health, secondary MCLs, or human health advisory levels. The data from the grid was interpolated to approximate constituent concentrations in the primary aquifer underlying the analysis area (Burton et al. 2012). The USGS designated concentrations as high if they were greater than an applicable threshold, and “moderate” if they were greater than one-half of the applicable threshold or at least 10% of applicable thresholds for organic and special-interest constituents. The study characterized non-detections and concentrations less than moderate levels as low. The primary findings of the 2012 USGS study included the following:

- TDS levels were estimated to be high in 14% and at moderate levels in 17% of the primary Project Area aquifer.
- Sulfate was estimated to occur in high concentrations in 8% and at moderate concentrations in 6% of the primary aquifer.

- Chloride was estimated to be present at high concentrations in 2% and at moderate concentrations in 4% of the primary aquifer.
- Iron and/or manganese were present at high concentrations in 13% and at moderate concentrations in 6% of the primary aquifer.
- Trace or minor elements were found to be present at high concentrations in 20% and at moderate concentrations in 27% of the primary aquifer. More specifically:
  - Fluoride was reported at high concentrations in 4% and at moderate concentrations in 2% of the primary aquifer.
  - Arsenic, antimony, boron, and vanadium occurred at high concentrations in 2% of the primary aquifer, mainly near the southern Tehachapi mountains.
  - Lead, thallium, and selenium were detected at high concentrations in less than 2% of the primary aquifer.
  - Nitrate was found at high concentrations in 5% and at moderate concentrations in 13% of the primary aquifer. The USGS study did not determine whether high and moderate nitrate detections were related to natural background conditions, agricultural and livestock operations, or septic tank systems.
  - Solvents, including carbon tetrachloride and trichloroethene, were reported at high concentrations in less than 1% and at moderate concentrations in 4% of the primary aquifer.
  - Trihalomethanes, a constituent potentially attributable to municipal water disinfection and chlorinated landscape irrigation water were present at moderate concentrations in 4% of the primary aquifer.
  - VOCs (e.g., organic synthesis reagents and gasoline hydrocarbons) were not detected at high concentrations and were found in moderate concentrations (specifically for benzene) in 2% of the primary aquifer.
  - The fumigant DBCP was reported at high concentrations in 2% of the primary aquifer, and DBCP and other fumigants were found at moderate concentrations in 4% of the primary aquifer.
  - Perchlorate, an inorganic constituent, and NDMA, a semi-volatile organic compound, were not found at high concentrations in the primary aquifer, but perchlorate was detected at moderate concentrations in 6% of the aquifer.
  - Naturally-occurring radioactive constituents, primarily radium and uranium, were detected at high concentrations in 6% and at moderate concentrations in 13% of the primary aquifer.

Water quality testing data available online from 2007 to 2013 were compiled for GAMA, California Department of Public Health, DWR, and other wells that are monitored for public drinking and M&I water supplies, agricultural irrigation, and other purposes in each of the Project Subareas. The dataset includes wells that are screened in shallower locations, generally above the depth of the impermeable clay layer in the region, and deeper wells screened below the clay boundary. The locations of the wells for which 2007 through 2012 water quality data were analyzed are shown on Figure 4.9-14.

Table 4.9-17 summarizes the data results for shallow wells in the 2007 to 2013 dataset. The shallower wells were generally installed above the level of the Corcoran Clay or equivalent clay layers in the Project Area.

The shallow well data for 2007 through 2013 shows that, in general, the Western Subarea has significantly lower groundwater quality than is typical of the Central and Eastern Subareas. TDS levels in the Western Subarea averaged 12,433 mg/L, compared with an average of 931 mg/L in the Central Subarea and 5,789 mg/L in the Eastern Subarea. Average chloride, bicarbonate, selenium, and vanadium levels were several times higher in the Western Subarea than in the Central and Eastern Subareas. Boron was detected in the Central Subarea, but not in the Western and Eastern Subareas where oil activities occur to a much greater extent. Arsenic levels were higher in the Eastern Subarea, a result consistent with the elevated arsenic levels detected in blended produced water supplied to the CWD discussed above. Expanded monitoring of blended produced water and other irrigation water is also being required more generally in the Project Area (Cart 2015a).

Table 4.9-18 summarizes the data results for the deeper wells in the 2007 to 2013 dataset. These wells were generally located at depths below the Corcoran Clay or equivalent clay layers in the Project Area.

The deeper well data for 2007 through 2013 exhibit less variation among the Project Subareas, although most constituent concentrations were higher in the Western Subarea. Average iron and bicarbonate levels were highest in the Eastern Subarea. Average and median chloride levels in the deeper well dataset were below the secondary MCL (250 mg/L) in all locations. Boron was detected in some Western Subarea wells above the California notification level of 1 mg/L.

The 2007 to 2013 groundwater quality data are generally consistent with the USGS data summaries and indicate that groundwater quality improves from west to east in the Project Area. The observed groundwater quality differences between the three Subareas are influenced, in part, by geologic factors. Streams recharging groundwater in the Eastern Subarea and in most of the Central Subarea originate in the Sierra Nevadas and flow for longer, more sustained periods of time through channels underlain by low-solubility igneous and metamorphic rocks. As a result, Eastern and Central Subarea water composition tends to exhibit a calcium-carbonate character, with lower TDS levels. Groundwater recharge in the Western Subarea is mainly a function of infrequent runoff carried by ephemeral channels incised into the Coast Ranges. The channels flow through marine-derived sedimentary materials that are more easily dissolved and mineralize surface flows and underlying groundwater. For example, sulfate is present at elevated concentrations in west subbasin groundwater due to contact with gypsum-containing sediments. Elevated sodium concentrations in the Western Subarea also reflect the exchange of calcium and magnesium ions for sodium and potassium ions initially bound to clay minerals in the marine sediments.

Table 4.9-17: Shallow Well Water Quality 2007 to 2013 Data Summary

Water Quality Parameters	Units	Western							Central							Eastern						
		Average	**Median**	**Min(a)**	**Max(b)**	**Number of Wells**	**Number of Samples**	**Number of Non-detects**	**Average**	**Median**	**Min(a)**	**Max(b)**	**Number of Wells**	**Number of Samples**	**Number of Non-detects**	**Average**	**Median**	**Min(a)**	**Max(b)**	**Number of Wells**	**Number of Samples**	**Number of Non-detects**
General Water Quality																						
Alkalinity, Bicarbonate	mg/L	2,002	2,650	69	11,342	11	186	0	239	220	55	647	23	39	0	222	240	93	443	18	113	0
Chloride	mg/L	3,880	3,700	981	10,100	23	203	0	201	180	41	576	40	223	0	292	200	39	946	20	121	0
Magnesium	mg/L	184	110	21	600	23	203	0	24	20	5.1	64	39	224	0	171	170	10	838	19	117	1
Nitrite	mg/L	0.0	ND	ND	0.0	12	12	7	0.1	ND	0.2	2.1	30	298	278	-	-	-	-	0	-	0
Nitrate	mg/L	50	ND	0.6	370	27	125	65	3.0	0.1	0.1	20	40	348	160	ND	-	-	-	1	5	5
Potassium	mg/L	35	28	5.8	109	23	203	0	4.9	4.7	2.7	8.1	39	225	0	38	38	3.5	171	19	116	6
Sodium	mg/L	3,541	4,200	684	10,361	23	203	0	59	54	30	100	39	225	0	2,127	580	42	7,679	19	117	0
Conductivity	µS/cm	17,000	17,768	6,083	39,299	11	191	0	-	-	-	-	0	-	0	9,300	10,171	2,120	28,039	6	7	0
Sulfate	mg/L	2,825	2,000	634	7,017	33	217	0	141	64	7.6	558	41	225	1	4,203	2,500	55	25,877	20	121	0
Total Organic Carbon	**mg/L**	**-**	**-**	**-**	**-**	**0**	**-**	**0**	**-**	**-**	**-**	**-**	**0**	**-**	**0**	**-**	**-**	**-**	**-**	**0**	**-**	**0**
Total Dissolved Solids	**mg/L**	**12,433**	**12,000**	**4,458**	**26,827**	**23**	**198**	**0**	**961**	**830**	**273**	**2,274**	**40**	**203**	**0**	**5,793**	**4,050**	**341**	**21,485**	**20**	**120**	**0**
Metals																						
Antimony	µg/L	0.0	ND	0.0	0.0	12	12	0	0.0	0.0	-	-	6	4.0	0	ND	0.0			6	16	0
Arsenic	µg/L	10	7.8	4.7	38	18	19	7	19	5.0	2.5	97	46	62	38	173	5.9	0.7	494	10	31	11
Barium	µg/L	29	11	3.3	83	18	19	6	179	180	49	441	40	189	1	33	29	13	97	7	20	4
Cadmium	µg/L	0.7	0.4	0.2	3.0	18	19	8	0.7	ND	-	-	20	21	21	3.3	1.0	1.6	17	6	16	8
Copper	µg/L	2.1	3.0	2.5	4.4	18	19	7	2.5	ND	2.3	15	23	30	21	1.9	ND	3.1	15	6	16	12
Chromium, Total	µg/L	4.0	ND	5.5	12	18	19	10	2.3	2.5	1.5	7	46	62	50	0.2	ND	0.6	1.3	6	16	13
Iron, Total	µg/L	ND	ND	-	-	12	12	12	610	15	30	2,748	39	224	111	1,275	160	61	4,942	19	113	47
Lead	µg/L	ND	ND	-	-	18	19	19	2.0	ND	2.0	23	48	162	149	ND	ND			6	16	16
Manganese	µg/L	18	3.2	0.4	42	12	12	1	955	180	31	6,370	39	224	60	401	30	7.5	4,982	5	19	6
Nickel	µg/L	78	27	10	235	18	19	1	4.1	2.5	1.2	10	28	44	34	21	5.5	10	117	6	16	8
Selenium	µg/L	168	180	13	1,238	18	19	5	7.1	ND	5.9	53	20	21	15	39	4.4	4.4	341	6	16	8
Uranium	pCi/L	-	-	-	-	0	0	0	-	-	-	-	0	0	0	-	-	-	-	0	0	0
Vanadium	µg/L	7.5	ND	3.2	41	18	19	10	1.1	ND	2.3	3.0	20	21	18	-	-	-	-	0	0	0
Zinc	µg/L	13	19	13	32	18	19	7	35	24	8.8	153	23	30	9	3.3	ND	4.1	30	6	16	12
Other Water Quality Parameters																						
1,2-Dichloroethane	mg/L	0.0	ND	0.0	0.0	35	278	235	0.0	ND	0.0	0.2	43	413	223	0.0	ND	0.0	0.2	16	102	82
Boron	mg/L	-	-	-	-	5	-	0	1.2	1.3	0.3	3.1	15	9	0	-	-	-	-	0	-	0

Table 4.9-17: Shallow Well Water Quality 2007 to 2013 Data Summary

Water Quality Parameters	Units	Western							Central							Eastern						
		Average	Median	Min[(a)]	Max[(b)]	Number of Wells	Number of Samples	Number of Non-detects	Average	Median	Min[(a)]	Max[(b)]	Number of Wells	Number of Samples	Number of Non-detects	Average	Median	Min[(a)]	Max[(b)]	Number of Wells	Number of Samples	Number of Non-detects
Bromide	mg/L	14	7.0	2.7	35	0	87	0	0.2	0.2	0.1	0.2	0	17	0	-	-	-	-	0	-	0
Fluoride	mg/L	-	-	-	-	0	-	0	-	-	-	-	3	-	0	-	-	-	-	0	-	0
SDWA Regulated Constituents																						
Primary drinking water standards																						
Disinfection Byproducts																						
Trihalomethanes	mg/L	-	-	-	-	0	-	0	-	-	-	-	0	-	0	-	-	-	-	0	-	0
Organics																						
Benzene	mg/L	0.1	ND	0.0	1.2	42	456	332	0.2	ND	0.0	0.4	292	3,070	2,367	0.0	ND	0.0	0.7	26	228	155

Source: Appendix S-1, 2015 FEIR (GAMA Database, Dataset EDF – assumed to be environmental monitoring wells screened above the Corcoran Clay [SWRCB 2014])
Notes:
(a) Minimum value calculated as the 5th percentile. When one or more result is ND, the minimum is reported as ND.
(b) Maximum value calculated as the 95th percentile.
(c) Some of the constituents and parameters listed above (e.g., General Water Quality) may also be regulated under the SDWA
Key:
μg/L = micrograms per liter
mg/L = mg/L = milligrams per liter
ND = not detected above the method reporting limit
pCi/L = picocuries per liter Where "ND", average, median, minimum, and maximum are calculated assuming a concentration of zero (no reporting limit provided by data source)
SDWA = Safe Water Drinking Act

Table 4.9-18: Deep Well Water Quality 2007 to 2013 Data Summary

Water Quality Parameters	Units	Western							Central							Eastern						
		Average	Median	Min(a)	Max(b)	Number of Wells	Number of Samples	Number of Non-detects	Average	Median	Min(a)	Max(b)	Number of Wells	Number of Samples	Number of Non-detects	Average	Median	Min(a)	Max(b)	Number of Wells	Number of Samples	Number of Non-detects
General Water Quality																						
Alkalinity, Bicarbonate	mg/L	89	83	19	270	22	38	3	96	90	33	218	223	446	2	157	150	76	279	71	117	0
Calcium	mg/L	64	36	12	180	22	38	2	37	30	8	103	225	461	0	72	52	15	189	72	122	0
Chloride	mg/L	118	39	8.3	366	22	38	2	34	23	7.4	85	224	466	1	81	41	10	252	73	130	0
Magnesium	mg/L	6.3	0.7	0.0	26	22	38	3	3.5	2.3	0.1	22	225	459	66	12	8.4	0.8	51	72	122	0
Nitrite	mg/L	0.0	0.0	0.0	0.2	25	43	40	0.0	ND	0.0	0.8	252	582	522	0.0	0.0	0.0	0.3	81	146	137
Nitrate	mg/L	12.4	6.9	0.4	85	28	150	33	20	16	1.3	109	285	2,665	182	22	16	1.3	127	90	1,146	49
Potassium	mg/L	1.7	0.7	0.2	4.8	22	38.0	15	1.5	1.4	0.6	3.9	216	430	178	3.8	3.3	1.4	8.5	69	112	8
Sodium	mg/L	107	76	25	274	22	38	2	43	31	14	90	225	451	0	63	52	23	131	72	122	0
Conductivity	µS/cm	603	946	233	2,362	22	42	1	360	434	186	797	229	566	0	588	693	268	1,375	75	190	0
Sulfate	mg/L	165	89	18	561	22	38	2	56	26	8.1	132	225	458	3	108	55	16	304	71	122	0
Total Organic Carbon	**mg/L**	-	-	-	-	**0**	-	**0**	**1.0**	**0.4**	**0.1**	**1.3**	**94**	**219**	**90**	**0.2**	**0.1**	**0.1**	**1.0**	**12**	**12**	**7**
Total Dissolved Solids	**mg/L**	**593**	**510**	**138**	**1,568**	**22**	**36**	**0**	**266**	**210**	**105**	**491**	**224**	**454**	**0**	**449**	**310**	**138**	**985**	**73**	**125**	**0**
Metals																						
Antimony	µg/L	0.0	0.0	0.0	0.0	22	37.0	36	0.0	0.0	0.0	0.0	243	488	441	0.0	0.0	0.0	0.0	77	127	118
Arsenic	µg/L	9.0	4.9	1.6	28	27	253	37	8.0	4.9	0.9	35	251	1,228	317	8.7	6.4	1.3	30	83	929	73
Barium	µg/L	33	24	10	90	22	37	5	33	6.8	4.5	293	244	489	262	77	62	32	228	77	130	39
Cadmium	µg/L	0.2	0.1	0.3	0.8	22	37	37	0.2	ND	0.1	1.5	244	489	485	0.3	0.1	0.2	1.1	77	130	129
Copper	µg/L	3.6	1.0	0.9	17	21	47	40	6.2	0.6	0.9	40	228	500	421	11	5.0	1.3	46	72	135	115
Chromium, Total	µg/L	3.0	4.0	1.4	11	22	37	32	2.4	0.5	0.8	17	244	492	421	2.9	1.5	1.4	14	77	134	125
Iron, Total	µg/L	195	25	6.1	589	19	35	27	64	0.0	5.8	338	225	521	432	533	25	5.9	2,038	73	143	95
Lead	µg/L	0.5	0.5	0.2	1.7	21	42	36	0.9	0.1	0.1	4.2	237	508	418	1.0	0.5	0.1	4.5	76	138	117
Manganese	µg/L	9.2	5.0	1.9	48	19	35	28	5.8	0.1	0.5	49	225	513	453	18	5.0	1.0	98	73	136	103
Nickel	µg/L	2.7	5.0	1.5	12	22	37	36	2.2	ND	0.5	20	244	491	467	3.4	0.5	1.0	18	77	132	122
Selenium	µg/L	2.1	1.0	0.3	8.6	23	41	34	1.1	0.4	0.3	5.1	244	489	380	1.5	1.0	0.5	6.7	77	130	87
Uranium	pCi/L	15	15	4.5	36	9	22	0	7.6	2.4	0.2	49	109	304	26	15	7.6	0.3	129	27	82	3
Vanadium	µg/L	6.6	4.9	2.5	14	3	3	0	8.4	4.8	0.9	25	67	94	12	11	9.0	1.8	39	10	11	0
Zinc	µg/L	18	10	8.7	83	19	35	30	12	ND	2.6	83	224	453	396	25	10	3.1	180	71	119	100
Other Water Quality Parameters																						
1,2-Dichloroethane	mg/L	0.0	0.0	-	-	20	28	28	0.0	ND	0.0	0.0	241	1,439	1,439	0.0	ND	0.0	0.0	68	167	167
Boron	mg/L	1.6	0.3	0.0	8.3	10	62	4	0.2	0.1	0.0	0.4	26	487	10	0.2	0.2	0.1	0.5	8	131	0

Table 4.9-18: Deep Well Water Quality 2007 to 2013 Data Summary

Water Quality Parameters	Units	Western							Central							Eastern						
		Average	Median	Min(a)	Max(b)	Number of Wells	Number of Samples	Number of Non-detects	Average	Median	Min(a)	Max(b)	Number of Wells	Number of Samples	Number of Non-detects	Average	Median	Min(a)	Max(b)	Number of Wells	Number of Samples	Number of Non-detects
Bromide	mg/L	0.1	0.1	0.0	4.4	1	16	0	0.1	0.1	0.0	3.1	10	47	0	0.2	0.2	0.1	0.3	0	8	0
Fluoride	mg/L	0.1	0.1	-	-	22	1	5	0.1	0.1	0.0	0.2	244	18	73	-	-	-	-	77	-	15
SDWA Regulated Constituents																						
Primary drinking water standards																						
Disinfection Byproducts (DBPs)																						
Trihalomethanes	mg/L	0.0	0.0	0.0	0.0	20	32	27	0.0	ND	0.0	0.0	233	1,434	1,252	0.0	ND	0.0	0.0	68	170	159
Organics																						
Benzene	mg/L	0.0	0.0	-	-	20	28	28	0.0	ND	0.0	0.0	241	1,440	1,440	0.0	ND	0.0	0.0	68	191	186

Source: Appendix S-1 in 2015 FEIR (GAMA Database, Dataset CDPH – assumed to be deep wells screened below the Corcoran Clay [SWRCB 2014])
Notes
(a) Minimum value calculated as the 5th percentile. When one or more result is ND, the minimum is reported as ND.
(b) Maximum value calculated as the 95th percentile.
(c) Some of the constituents and parameters listed above (e.g., General Water Quality) may also be regulated under the SDWA
Where "ND", average, median, minimum, and maximum are calculated assuming a concentration of zero (no reporting limit provided by data source).
Key:
µg/L = micrograms per liter
CDPH = California Department of Public Health
mg/L = mg/L = milligrams per liter
ND = not detected above the method reporting limit
pCi/L = picocuries per liter

As of 2012, there were 235 sites had active federal NPDES permits issued under the CWA, and 167 facilities had active WDRs (56 general WDRs and 112 individual WDRs) issued under state law in the Project Area and in adjacent urban and other locations. A list of the NPDES permits and WDRs issued within the Project Area is provided in Tables B-1 and B-2 of Appendix B in the 2015 FEIR.

Groundwater Quality and Existing Oil and Gas Operations

Section IV of the Tulare Lake Basin plan states that "[o]il field producers continue to use hundreds of sumps as oil/wastewater separators and as wastewater disposal sumps. Some oilfield wastewaters contain salts, oil and grease, metals, and organics which can present a threat to the beneficial uses of underlying good quality ground water." The Tulare Lake Basin Plan also states that, "[d]ue to historical practices, degradation of ground water from oil field wastewater disposal occurred in some areas. The petroleum industry has been eliminating oilfield wastewater disposal sumps." In response, the Tulare Lake Basin Plan indicates that "[w]ith the gradual elimination of the use of sumps for disposal, increased amounts of produced wastewater are being discharged to Class II injection wells" (CVRWQCB 2004).

Consistent with the Basin plan summary of sump and pond use, since 1993, the volume of produced water and other permitted Class II well injection activities, including reuse and disposal in the Project Area, has nearly doubled from a low of about 104,900 AF in 2001 to 193,500 AF in 2013 (Figure 4.9-15).

As shown in Table 4.9-19, total Class II injection volumes in the Project Area rose by about 88,500 AF during 2001 through 2013. Produced water disposal accounted for over 61% of this increase (54,200 AF). About 38% of the net injection growth in the Project Area since 2001 was from increased cyclic steam and water flood EOR activities.

Table 4.9-19: Project Area Injection Volumes, 2001 to 2013

	2001 (AF)	**2013 (AF)**	**Net Increase (AF)**	**Percent of Increase**
Cyclic Steam EOR	9,727	19,712	9,985	11%
Steam Flood EOR	38,641	38,801	160	0.2%
Water Flood EOR	24,525	48,673	24,149	27%
Water Disposal	32,059	86,294	54,235	61%
TOTAL	**104,952**	**193,480**	**88,528**	**100%**

Source: DOGGR 2014
Note:
Data is for all District 4 fields and includes a small amount of production activity outside of the Project Area.
Key:
AF = acre-feet
EOR = enhanced oil recovery

Water quality in hydrocarbon zones and other aquifers beneath existing oil fields is compiled by CALGEM based on subsurface logs and drilling information reported on field data sheets. In many cases, the sheets identify hydrocarbon pools and water quality information that are located in more than one geologic formation. The datasheets and geologic cross-sections for Project Area oil fields are included in CALGEM's summary of California Oil Fields, Volume 1 - Central California (DOGGR 1998). The datasheets for Project Area well fields include formation, pool, and associated water quality information developed during various periods since the early 1900s. Some of the datasheets also identify the presence and depth to the base of "fresh" water resources located above the hydrocarbon formation. As discussed above, the definition of fresh water is subject to variation in different regulatory contexts. The CALGEM oil field data generally identify fresh water as an aquifer with TDS levels of less than 3,000 mg/L.

A summary of the primary formations, hydrocarbon bearing pools, stratigraphic information, and average pool depth for Project Area oil fields by Subarea is included in Table 2.1 of Appendix S-1 in the 2015 FEIR. Table J-11 in the CalGEM draft EIR (DOGGR 2015a) summarizes available salinity data and TDS concentrations in the hydrocarbon-bearing zones and the depth to the base of freshwater for each of the oil fields in the Project Area. These data indicate that groundwater quality in hydrocarbon bearing zones that would generate produced water during oil and gas production varies from field to field and in different formations within a single field.

In 1989, CalGEM (then DOGGR) conducted a study of the effects of oil field operations on USDWs in Kern County (Mitchell 1989). The study included water quality data derived from groundwater samples in 18 Project Area oil fields. Table 4.9-20 summarizes the water quality analysis results of the DOGGR study for the 18 fields.

The range of oil field groundwater quality data in the 1989 study results was similar to the results summarized in the California oil fields datasheets maintained by DOGGR. Average TDS levels in some fields were below 10,000 mg/L; in others, TDS levels approached the salinity levels associated with seawater (35,000 mg/L).

In 2015, Kennedy-Jenks reviewed existing WDRs for surface water discharges of produced water in the Project Area. Sixteen WDRs issued over the period from 2002 to 2012 were found to report data on produced water quality data (see Appendix S-1, 2015 FEIR). Table 4.9-21 summarizes the reported TDS, chloride, boron, and benzene, toluene, ethylbenzene, and xylene levels in produced water at each location.

Table 4.9-20: Produced Water Quality, 1989 DOGGR Analysis

Field		TDS (ppm)	Sodium (ppm)	Calcium (ppm)	Magnesium (ppm)	Barium (ppm)	Bicarbonate (ppm)	Chloride (ppm)	Sulfate (ppm)	Boron (ppm)	Iodide (ppm)	pH
Antelope Hills	Average Median Minimum Maximum *N*	7,142	2,431	14	10	2	2,162	2,291	58	20	-	8.3
		7,807	2,485	11	10	-	2,379	2,048	29	20	-	8.4
		2,394	710	5	4	-	1,098	483	0	12	-	8.0
		10,699	3,784	29	15	-	3,223	4,300	173	27	-	8.4
		5	*5*	*5*	*4*	*1*	*5*	*5*	*5*	*2*	-	*5*
Asphalto	Average Median Minimum Maximum *N*	24,282	8,587	86	28	9	3,611	11,604	61	-	6	7.9
		27,605	9,957	104	21	5	3,908	13,330	36	-	-	7.9
		15,296	3,674	15	11	5	2,001	5,510	15	-	-	7.2
		29,293	10,949	149	61	17	4,652	15,602	218	-	-	8.6
		9	*9*	*9*	*9*	*3*	*9*	*9*	*9*	-	*1*	*9*
Belgian Ant	Average Median Minimum Maximum *N*	13,043	4,663	200	44	-	1,291	6,203	25	159	-	7.9
		15,353	5,611	178	43	-	1,354	6,800	17	126	-	7.9
		3,610	935	87	32	-	644	1,050	10	96	-	7.3
		16,334	6,040	324	60	-	1,830	9,367	61	256	-	8.4
		5	*5*	*5*	*5*	-	*5*	*5*	*5*	*3*	-	*4*
Blackwells Corner	Average Median Minimum Maximum *N*	16,276	5,877	192	269	-	3,404	8,191	19	-	-	7.3
		-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-
		1	*1*	*1*	*1*	-	*1*	*1*	*1*	-	-	*1*
Buena Vista (Front)	Average Median Minimum Maximum *N*	30,809	9,865	980	400	9	222	17,827	202	10	-	7.7
		34,623	11,695	1,107	415	9	224	21,161	4	10	-	7.6
		22,848	6,061	685	350	8	192	10,975	2	10	-	7.5
		34,956	11,839	1,147	434	9	249	21,345	600	10	-	7.9
		3	*3*	*3*	*3*	*2*	*3*	*3*	*3*	*1*	-	*3*
Buena Vista (Hills)	Average Median Minimum Maximum *N*	14,971	4,980	349	294	18	381	8,920	29	-	-	-
		-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-
		1	*1*	*1*	*1*	*1*	*1*	*1*	*1*	-	-	-
Chico Martinez	Average Median Minimum Maximum *N*	22,183	7,508	197	277	5	3,472	10,716	7	-	-	6.9
		22,183	7,508	197	277	5	3,472	10,716	7	-	-	6.9
		21,984	7,455	174	242	4	3,148	10,299	1	-	-	6.9
		22,381	7,560	220	312	6	3,795	11,132	13	-	-	7.0
		2	*2*	*2*	*2*	*2*	*2*	*2*	*2*	-	-	*2*

Table 4.9-20: Produced Water Quality, 1989 DOGGR Analysis

Field		TDS (ppm)	Sodium (ppm)	Calcium (ppm)	Magnesium (ppm)	Barium (ppm)	Bicarbonate (ppm)	Chloride (ppm)	Sulfate (ppm)	Boron (ppm)	Iodide (ppm)	pH
Cymric	Average	7,541	2,362	92	102	0	2,303	2,688	31	-	-	7.1
	Median	-	-	-	-	-	-	-	-	-	-	-
	Minimum	-	-	-	-	-	-	-	-	-	-	-
	Maximum	-	-	-	-	-	-	-	-	-	-	-
	N	*1*	*1*	*1*	*1*	*1*	*1*	*1*	*1*	-	-	*1*
Elk Hills	Average	25,821	8,385	877	388	5	1,287	14,652	310	17	58	7.3
	Median	29,032	10,015	934	371	5	354	16,885	67	18	55	7.3
	Minimum	952	287	24	3	4	43	520	2	4	41	6.2
	Maximum	47,074	16,104	2,446	1,114	5	5,287	29,217	2,063	29	80	8.0
	N	*21*	*21*	*21*	*21*	*2*	*21*	*21*	*21*	*3*	*4*	*20*
Lost Hills	Average	22,840	7,050	284	170	10	1,779	12,842	793	114	-	7.4
	Median	22,869	6,467	240	144	9	1,026	13,967	26	110	-	7.4
	Minimum	7,247	115	16	5	6	232	3,829	0	36	-	6.7
	Maximum	31,886	12,469	810	531	15	3,485	17,340	7,570	202	-	8.0
	N	*11*	*11*	*11*	*11*	*3*	*11*	*10*	*10*	*4*	-	*11*
McDonald Ant.	Average	8,658	3,307	40	11	-	5,189	2,386	33	12	-	8.4
	Median	8,989	3,307	40	11	-	5,189	2,386	33	-	-	8.3
	Minimum	3,350	2,650	5	10	-	2,326	1,461	27	-	-	8.1
	Maximum	13,635	3,964	74	11	-	8,052	3,310	38	-	-	8.8
	N	*3*	*2*	*2*	*2*	-	*2*	*2*	*2*	*1*	-	*3*
McKittrick	Average	13,801	4,838	85	46	-	3,789	5,510	15	72	-	7.8
	Median	11,829	3,883	80	55	-	3,638	4,505	5	72	-	7.8
	Minimum	9,052	3,379	36	7	-	2,166	2,937	2	33	-	7.8
	Maximum	26,672	9,292	148	75	-	5,694	11,300	54	111	-	7.8
	N	*6*	*5*	*5*	*5*	-	*5*	*5*	*5*	*2*	-	*2*
Midway Sunset	Average	12,008	4,426	156	143	-	2,802	5,622	153	76	-	7.9
	Median	10,829	3,438	41	54	-	2,895	4,326	38	52	-	8.0
	Minimum	4,479	1,323	5	2	-	738	300	0	10	-	6.5
	Maximum	29,702	10,391	586	525	-	4,941	16,600	441	248	-	8.6
	N	*13*	*14*	*14*	*14*	-	*14*	*14*	*11*	*7*	-	*12*
N. Antelope Hills	Average	20,722	7,800	112	64	-	2,393	11,307	-	48	-	-
	Median	20,722	-	-	-	-	2,393	11,307	-	48	-	-
	Minimum	19,924	-	-	-	-	2,393	11,109	-	34	-	-
	Maximum	21,520	-	-	-	-	2,393	11,505	-	61	-	-
	N	*2*	*1*	*1*	*1*	-	*1*	*2*	-	*2*	-	-

Table 4.9-20: Produced Water Quality, 1989 DOGGR Analysis

Field		TDS (ppm)	Sodium (ppm)	Calcium (ppm)	Magnesium (ppm)	Barium (ppm)	Bicarbonate (ppm)	Chloride (ppm)	Sulfate (ppm)	Boron (ppm)	Iodide (ppm)	pH
N. Belridge	Average Median Minimum Maximum *N*	19,287	6,899	367	61	-	653	10,713	605	-	-	7.0
		21,829	7,938	357	46	-	656	12,184	477	-	-	7.1
		360	137	27	4	-	233	121	9	-	-	6.2
		42,523	14,915	971	185	-	1,227	24,375	1,298	-	-	7.8
		7	*7*	*7*	*7*	-	*7*	*7*	*7*	-	-	*4*
Paloma	Average Median Minimum Maximum *N*	18,218	6,527	184	38	-	2,265	9,139	66	-	-	6.8
		19,605	7,090	188	37	-	2,471	9,780	78	-	-	6.8
		8,920	3,067	127	26	-	659	4,895	16	-	-	6.6
		24,742	8,862	232	51	-	3,460	12,100	92	-	-	7.2
		4	*4*	*4*	*4*	-	*4*	*4*	*4*	-	-	*4*
Pleito Ranch	Average Median Minimum Maximum *N*	11,958	3,896	488	86	-	634	6,674	125	43	-	7.5
		-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-
		1	*1*	*1*	*1*	-	*1*	*1*	*1*	*1*	-	*1*
S. Belridge	Average Median Minimum Maximum *N*	19,723	7,275	232	234	-	2,434	10,524	497	47	-	7.7
		13,391	4,467	177	234	-	1,976	7,135	103	47	-	7.8
		2,034	663	24	57	-	259	516	1	33	-	7.2
		48,262	17,244	485	407	-	5,514	25,314	2,662	61	-	8.1
		7	*7*	*7*	*7*	-	*7*	*7*	*7*	*2*	-	*4*

Source: 2015 FEIR Appendix S-1 (Data from Mitchell 1989)
Key:
N = number of analyses reported
Ppm = parts per million
TDS = Total Dissolved Solids

Table 4.9-21: Produced Water Quality in CVRWQCB WDRs, 2002-2014

Permit ID	Permittee	Lease	Site	APN	Concentration, mg/L			Concentration, µg/L			
					TDS	Chloride	Boron	Benzene	Toluene	Ethylbenzene	Xylene
R5-2002-0194	Petro Resources, Inc.	Sp-Section 29 Lease	Midway-Sunset Oilfield	220-080-29-5	24,000	12,600	37	170	11	180	250
R5-2002-0195	Petro Resources, Inc.	Sp–Section 33 Lease	Midway-Sunset Oilfield	220-091-17-5	24,000	12,600	37	170	11	180	250
R5-2002-0196	Pyramid Oil Company	Section 28 Lease	Midway-Sunset Oilfield	220-080-28-7	32,350	19,140	53	-	-	-	-
R5-2002-0197	Pyramid Oil Company	Pike Lease	Midway-Sunset Oilfield	220-080-28-7	32,350	19,140	53	-	-	-	-
R5-2004-0056	Bob Ferguson – Independent	Government - Ferguson Lease	Asphalto Oilfield	157-220-08-00-1	25,000	15,000	175	12.5	<5	<5	<5
R5-2004-0057	Cather-Herley Oil Company	California Federal A Lease	Asphalto Oilfield	157-220-06-00-5	25,000	15,000	175	12.5	<5	<5	<5
R5-2004-0058	Crimson Resource Management Corp.	Asphalto Standard Lease	Asphalto Oilfield	57-210-05-00-9	25,000	15,000	175	12.5	<5	<5	<5
R5-2005-0163	Howard E. Caywood, Inc.	Section 19 & 24 Leases	Midway-Sunset Oilfield	298-040-23-9	22,000	12,000	28	-	-	-	-
R5-2006-0072	Aera Energy LLC	South Wastewater Disposal Facility	South Belridge Oilfield	098-113-04-6	13,000	68,000	90	-	-	-	-
R5-2006-0073	Aera Energy LLC	Row 4 / Lost Hills Wastewater Disposal Facility	South Belridge Oilfield	085-220-31-7	24,000	13,000	80	-	-	-	-
R5-2006-0134	Aera Energy LLC	Highway 33 Wastewater Disposal Facility	South Belridge Oilfield	085-210-45	33,000	13,000	78	-	-	-	-
R5-2006-0135	Aera Energy LLC	Reagan Wastewater Disposal Facility	South Belridge Oilfield	085-210-18	33,000	14,000	83	-	-	-	-
R5-2013-0054	Aera Energy LLC	Post-Closure Maintenance and Corrective Action	North Belridge Oilfield	069-220-36	29,000	7,800	23	-	-	-	-
R5-2013-0056	Chevron USA, Inc.	Post-Closure Maintenance and Corrective Action Section 29 Surface Impoundments	Lost Hills Oilfield	058-180-18-3	11,000	4,200	15	-	-	-	-
R5-2013-0061	ExxonMobil Production Company Hill Lease Surface Impoundments	Post-Closure Maintenance and Corrective Action	South Belridge Oilfield	085-210-10-2	15,000	7,500	40	-	-	-	-
R5-2014-0019	Aera Energy LLC	North Belridge Solid Waste Disposal Site	Post-Closure Maintenance	085-110-10-01-9	3,300	750	1	-	-	-	-

Source: Appendix S-1, 2015 FEIR
Key:
APN = assessor's parcel number
µg/L = micrograms per liter
mg/L = milligrams per liter
TDS = total dissolved solids

In 2002, the California Department of Toxic Substances Control (DTSC) published a report on the findings of a field research analysis of oil exploration and production wastes conducted in 2000 and 2001. The purpose of the study was to obtain scientific data about the characteristics of oil exploration and production wastes, and determine whether the wastes were being properly managed in accordance with federal and state law. The study collected exploration and production waste samples at six oil production facilities in Los Angeles County and two oil production facilities in Kern County, including samples of produced water, drilling waste, oily sludge, and foam treatment waste. The DTSC concluded that none of the exploration and production waste streams sampled and analyzed during the study were hazardous under federal or state laws. Produced water and oily sludges were found in certain cases to meet federal toxicity characteristic for hazardous waste, but were exempted from regulation as a hazardous waste by law. Ten of 36 oily sludge samples—primarily the concentrated residue in the bottom of tanks and similar impoundments—exhibited other characteristics of hazardous waste under state law. The DTSC report concluded that, depending on formation characteristics or facility operations, certain exploration and production wastes, such as oily sludges, may be subject to management by the state as hazardous wastes even if they are exempted from hazardous waste regulations under federal law (DTSC 2002).

As shown in Table 4.9-1, about 30,223 AF of produced water was disposed in Project Area-produced water ponds in 2012. Almost all of these ponds were unlined, earthen ponds constructed in upland locations. The CVRWQCB and CalGEM are in the process of conducting an inventory of active and inactive ponds used for disposal of produced water in the Project Area and other locations in the San Joaquin Valley. Published reports indicate that, as of March 2015, the CVRWQCB had identified 355 inactive ponds previously used for produced water disposal, 370 ponds that are active and permitted, and 208 active ponds that were not issued WDRs or other disposal permits. According to the Project applicants, the CVRWQCB's initial list was based, in part, on outdated aerial maps, and the agency is currently updating this list of permitted and unpermitted ponds based on new information supplied by the oil and gas industry. The CVRWQCB has indicated that it intends to bring all active produced water ponds into regulatory compliance or require closure of any produced water ponds that cannot meet applicable water quality standards by December 2016 (BakersfieldNow.com 2015).

The Tulare Lake Basin Plan states that historical use of produced water ponds is known to have affected groundwater in the Project Area. The CVRWQCB has determined that produced water discharges into unlined ponds have impacted downgradient groundwater in several Project Area locations, including ponds adjacent to the North Belridge oil field (CVRWQCB 2013b), the Section 29 surface impoundments at the Lost Hills oil field (CVRWQCB 2013d) and ponds adjacent to the South Belridge oil field CVRWQCB 2013e). The produced water disposal facilities in these instances have been closed and are no longer in operation. Each CVRWQCB post closure order, described above, includes a monitoring and reporting program to monitor the extent of the impacts in groundwater and the natural attenuation of the impacts over time. Although downgradient water quality impacts have been documented from certain ponds, to date there is no confirmed instance documented by a regulatory agency in which the use of a produced water pond has impaired operational agricultural or drinking water wells. However, in 2001, an almond grower who owned orchards downgradient from unlined ponds located in the western Subarea filed a lawsuit asserting that produced water disposed to the unlined ponds had contaminated the groundwater underlying the orchard and killed the almond trees. In 2009, a jury ruled in the grower's favor and awarded the grower $8.5 million in damages, but subsequent efforts to obtain additional punitive damages were unsuccessful (Barrios 2013).

Prior to December 4, 2013, unlined sumps were used throughout the Project Area to contain drilling muds and drilling cuttings discharged when drilling a well. After December 4, 2013, these drilling mud pits have only been used in the Eastern and Western Subareas because coverage under the State Water Resources Control Board General Order 2003-0003-DWQ has not been obtained by any operator to use drilling mud pits in the Central Subarea. Drilling mud pits cannot be used for the discharge of other oil field wastes such as, but not limited to, well completion fluids, well stimulation treatment (WST) fluids, or produced water. A video posted online in October 2012 of a well drilling operation to the east of the City of Shafter, in the Central Subarea, shows the discharge of WST fluids to a drilling sump. After an investigation by CVRWQCB staff determined that WST fluids were in the drilling sump for 12 days, the operator agreed to pay the maximum administrative civil liability amount for the unpermitted discharge to the sump (CVRWQCB 2013f).

On November 2013, the CVRWQCB issued 78 investigative orders (Section 13267 Orders) to operators that required submission of well drilling and workover (repair and improvement) information during the period from January 1, 2012 to November 15, 2013. In 2014, CVRWQCB staff reported that all operators responded with the required information for 6,381 new wells and 8,291 workovers of existing wells (CVRWQCB 2014a).

Based on the information submitted by oil and gas operators, the CVRWQCB determined that unpermitted discharges of well completion fluids, produced water, or stimulation fluids had occurred to drilling sumps in other Project Area locations. Certain operators subsequently agreed to stipulated settlements and the payment of administrative civil liabilities related to unpermitted drilling sump violations, including unpermitted drilling sump discharges in the Western Subarea (CVRWQCB 2014a, 2014b) and the Poso Creek oil field (CVRWQCB 2014c) and, as of March 2015, a proposed civil liability settlement (CVRWQCB 2015) for the unpermitted discharge of well stimulation fluids in the South Belridge oil field. To date, there are no confirmed reports of impacts to surface water or groundwater quality associated with unpermitted discharges to drilling sumps in the Project Area.

Underground Injection Control

As shown on Figure 4.9-15 and in Table 4.9-19, oil and gas operators in the Project Area have significantly increased the use of Class II injection wells regulated under the UIC program under the federal SDWA to reduce the use of unlined surface ponds for produced water and other permitted disposal. Since 1983, CalGEM has administered the UIC program in California under the terms of a primacy agreement with the EPA and regulates all oil and gas EOR-related and produced water disposal injection activities in the Project Area. CalGEM and the SWRCB executed a memorandum of agreement (MOA) in 1988 that establishes CalGEM as the primary state agency for the approval of oil and gas production and exploration discharges in Class II wells. The MOA has been incorporated into the Tulare Lake Basin Plan (CVRWQCB 2004).

The primary objective of the SDWA and the UIC program is to protect existing and potential USDWs, which are defined by federal law to include aquifers with TDS concentrations of up to 10,000 mg/L. Injection wells used in connection with oil and gas exploration and production operations are regulated as Class II facilities under the UIC program. The SDWA prohibits any Class II well from injecting into a USDW unless the aquifer has been exempted in accordance with applicable criteria and regulatory requirements. Class II injection wells must be constructed to avoid any discharges into a non-exempt USDW, including the installation of multiple cement and pipe barriers to isolate well fluids from contact with USDWs that may be traversed by a well in shallower geologic formations.

In February 2015, the CCST published the first of three studies required by state legislation evaluating well stimulation, including a description of well construction requirements and technology used in California (CCST 2015). Multiple steps are required to install and secure wells with protective cement and pipe casing. The initial step is to install a steel pipe, or casing, with diameter slightly smaller than the borehole diameter as a well is drilled. The space between the pipe and the borehole wall, or the annulus, is then filled with cement to secure the casing. The cemented casing is designed to limit fluid movement in the well solely to the interior of the pipe, prevent borehole collapse, and hydraulically isolate, or ensure the zonal isolation of, all internal well flows from contact with adjacent rock formations or aquifers. Different types of cements are used to secure the casing, depending on the depth, temperature, pressure, and chemical environment of a well. A series of pressure tests and wireline logging using sonic and ultrasonic tools are performed to verify that the well has been correctly cemented and contains no locations where well fluids can leak to the surrounding formations.

Several layers of casing are installed in a well. As shown on Figure 4.9-16, the first is called the conductor casing and consists of a pipe with a diameter larger than other well casings. The conductor casing prevents surface materials from collapsing into the drill hole and is either driven into the ground by a pile driver or placed in the hole after drilling. The next layer of casing is called the surface casing and protects freshwater aquifers from drilling mud as well as well fluids carried during the life of the well. The surface casing is smaller in diameter than, and is installed inside, the conductor casing. The conductor casing extends from the bottom of the borehole to the ground surface. Depending on the depth of a well, a production casing or an intermediate casing may be installed. An intermediate casing is used in deeper wells for additional support. The production casing is a pipe that extends through at least part of the surface casing in shallow wells or the intermediate casing in deeper wells to the top of the oil or gas producing zone or to the bottom of the drilled hole. In some instances, a production liner may be sealed to a length of intermediate casing.

The cementing process is completed after each casing segment is installed into the borehole. Dispersants and spacers are pumped down the casing and to the bottom of the well and travel back to the surface in the borehole annulus to prepare the formation and case pipe for cement bonding. Cement that is designed to withstand the operational temperature and physical stresses associated with the well is added through the casing and fills the annulus to the surface. Once the cement sets, the residual cement and any remaining items from the cement operation that are at the bottom of the hole are drilled out to continue deepening the borehole.

The CCST study indicated that leakage due to casing and cement failures represents one of the most likely pathways for unintentional well fluid migration to underground formations (CCST 2015). Other studies have indicated that well failure, or blowout rates, in the Project Area have been significantly reduced over time by improved well construction technologies. Blowout rates due to well operations in California Oil and Gas District 4 from 1991 to 2005 ranged from one per 10,000 to one per 60,000 well-years, depending on the oil field activity taking place at the time of the blowout. In District 4, the well blowout rate was one in 20,000 well-years for all wells in operation, with a rate of one per 15,000 well-years in thermal-recovery fields and one per 60,000 well years in non-thermal-recovery fields during this period.

The number of blowouts per year in District 4 declined by about 80% between 1991 and 2005. The decline in some rates has been statistically significant, with the well construction blowout rate down from one per 1,500 operations in the 1990s to one per 5,200 operations in the 2000s, and the steam injection well blowout rate down from one per 6,000 well-years in the 1990s to one per 100,000 well-years in the 2000s. There is circumstantial evidence that rates decreased due to improvements in production practices, such as improved cementing of steam-injection wells and management of geomechanical processes in reservoirs. These downward trends do not correlate with changes in production activity in the district. This demonstrates that risk in the hydrocarbon industry has and can be significantly reduced with focused effort (Jordan and Benson 2009).

As of August 2014, the CalGEM online database indicated that there were 11,970 active wells in the Project Area used for steam flood, water flood, cyclic steam, or disposal injection. About 1,093 active injection wells were used for produced water and other disposal purposes. CalGEM has indicated that a total of 613 spills and 87 well leaks were reported in the Project Area (DOGGR District 4) from 2009 through 2014 (DOGGR 2015a). There have been no confirmed reports of drinking or agricultural groundwater quality impacts as a result of injection activity in the Project Area.

In 2011, the EPA published an independent audit of the California UIC program that identified a number of potential compliance issues, including the possibility that injection wells had been permitted to discharge into aquifers that met the USDW criteria but that had not been exempted in accordance with applicable requirements (Horsely-Witten Group 2011). A March 2015 report by the California Environmental Protection Agency indicated that discharges to nonexempt USDWs were apparently permitted due to (1) inconsistencies in the records maintained by state and federal officials regarding the exempt status of 11 aquifers located under oil fields that were operational in 1983 when CalGEM (then DOGGR) was granted primacy for the UIC program; and (2) other permitting errors, including (a) border confusion regarding the aerial extent of exemptions granted in conjunction with the documentation in the early 1980s compared with the larger extent of most oil field administrative boundaries; (b) expanding productive limits over time beyond the production portions of oil fields at the time when an aquifer was exempted; (c) depth confusion regarding the formations that are subject to exemption which resulted in injection above or below the exempt aquifer and into non-exempt zones; and (d) the fact that, in certain cases, only portions of an aquifer were exempted and not the entire aquifer (CalEPA 2015).

Eight of the 11 aquifers for which exemption records reflect inconsistencies are located in the Project Area. These aquifers are listed in Table 4.9-22 by oil field and with reference to the formation in which the aquifers occur.

Table 4.9-22: Project Area Oil Fields Subject to USDW Exemption Review

Oil Field	Geologic Formation
Blackwell's Corner	Tumey
Kern Bluff	Kern River
Kern Front	Santa Margarita
Kern River	Chanac
Kern River	Santa Margarita
Mount Poso	Walker
Round Mountain	Olcese
Round Mountain	Walker

Source: CATC 2015

The SWRCB and CALGEM initiated a work plan to address the UIC program issues identified by the EPA review and subsequent analysis of oil field operations. In February 2015, CalGEM, then DOGGR, provided the EPA, and publicly released, a list of 2,553 wells in the state that were injecting into non-exempt aquifers.

In May 2015, the SWRCB and CalGEM (then DOGGR) published a letter to the EPA stating that "approximately 3,600 cyclic steam wells that had some injection reported in 2014" had been identified, and that CalGEM databases show these wells "as not being associated to a permitted injection project." Almost all of these cyclic steam wells are located in the Project Area. The May 2015 letter states that because that most of the cyclic steam wells inject steam for a limited duration and volume into "zones laden with hydrocarbons" or formations with "little or essentially no permeability, the wells are "very unlikely" to pose a threat to water supply wells (DOGGR 2015c).

The March 2015 list of wells injecting into non-exempt aquifers also identified 532 disposal wells injecting into non-hydrocarbon producing zones, including 388 in the Project Area. These wells were referred to as "Category 1" for review because they were permitted to inject Class II fluid for disposal purposes "into non-exempt, non-hydrocarbon-bearing aquifers" or "into the 11 aquifers that have historically been treated as exempt." CalGEM determined that 176 of the 532 wells were injecting into zones containing water with TDS levels of less than 3,000 mg/L. About 163 of these wells are identified by CalGEM as located in Region 4, which generally comprises the Project Area (DOGGR 2015c). Due to their proximity to relatively high-quality groundwater, the UIC work plan developed by CalGEM has initially focused on these 176 wells and injection wells within one mile at the surface and within 500 vertical feet underground of a drinking or agricultural water supply. As of March 2015, 23 injection wells in the Project Area were ordered to cease operations due to proximity to drinking or agricultural water supplies. CALGEM has indicated that it will complete the review of the 176 highest priority injection wells by June 2015 (DOGGR 2015d).

In May 2015, the SWRCB and CalGEM (then DOGGR) published a letter to the EPA that provided updated information concerning the priority (Category 1) well review process. The letter indicated that 80 of the 532 Category 1 wells identified in February 2015 had been removed from the Category 1 list for various reasons, including injection into an aquifer that did not meet the criteria for a USDW, wells that had not been completed, or wells that were injecting into exempted aquifers. About 21 of the 176 wells identified in February 2015 as injecting into aquifers with less than 3,000 mg/L of TDS were removed from the Category 1 list. The May 2015 letter also indicated that SWRCB staff had determined that 53 of the remaining 155 wells injecting into aquifers with less than 3,000 mg/L of TDS were "potentially impacting drinking water supply wells." As discussed above, 23 of these wells had been ordered to cease operations due to proximity to drinking or agricultural water supplies. The May 2015 letter states that CalGEM and the SWRCB are "awaiting receipt of additional test data" before determining whether to order a shutdown of any of the other 30 wells by the October 15, 2015, compliance date (DOGGR 2015c).

On March 23, 2020, CalGEM and the SWRCB provided the EPA with a letter updating the status of the aquifer exemption program. The update states that CalGEM is continuing to work in coordination with the state board to develop, where appropriate, aquifer exemption proposals as a process to address the issue of Class II injection wells identified as currently permitted for injection into a potential USDW. The update includes a list of 30 aquifer exemption proposals, 20 of which are shown to have been approved by the EPA from 2017 and 10 of which continue to be processed. The update also identified eight other aquifer exemption proposals where current injection into a potential USDW has not been identified, one of which has been approved by the EPA, and seven of which continue to be processed. The letter states that progress in addressing the aquifer exemptions "continues to demonstrate the State's commitment to protecting public health and the environment while avoiding unnecessary disruption of oil and gas production" (CalGEM 2019a).

In 2015, several parties filed a lawsuit against CalGEM, stating that the aquifer exemption process implemented by the state and approved by the EPA was unlawful. The lawsuit contended that the state had a mandatory duty under the SDWA to order the immediate closure of oil and gas wells injecting fluids into unexempted aquifers. The lawsuit was denied in September 2016 by the Alameda County Superior Court. In August 2018, Superior Court's decision was upheld by the California Court of Appeal, which also denied request to review the appellate decision on October 24, 2018 (*Center for Biological Diversity v. California Department of Conservation* [2018] 26 Cal. App. 5th 161).

Well Stimulation

There have been no confirmed impacts to groundwater in the Project Area related to well stimulation, although analyses conducted to date generally recommend that additional groundwater data be developed to further assess this issue. In August 2014, the CCST, the Lawrence Berkeley National Laboratory, and the Pacific Institute published an assessment of well stimulation activities in California for the federal Bureau of Land Management (BLM) (CCST

2014). BLM leases land in California, including land located in Kern County, for oil and gas exploration and production. The study identified chemical constituents used in at least 2% of the reported well stimulation treatments in California, generally for the period of 2012 through 2014, and identified oral toxicity information where available for these constituents. The majority of the well stimulation chemicals considered in the CCST report, such as guar gum, a gelling agent, or ethanol, a common solvent, were determined to have low hazard potential in terms of oral toxicity. Certain chemicals, such as biocides (e.g., tetrakis [hydroxymethyl] phosphonium sulfate, 2,2-dibromo-3-nitrilopropionamide, and glutaraldehyde), corrosion inhibitors (e.g., propargyl alcohol), and mineral acids (e.g., hydrofluoric acid and hydrochloric acid) were found to present concerns for acute toxicity. Oral toxicity information was not available for about 30% of the constituents used in California well stimulation treatments. Table 4.9-23 lists the chemicals used in at least 2% of the reported well stimulation treatment chemicals for which chemical abstract serviceoral toxicity data could be identified by the CCST. Table 4.9-24 lists the chemicals used in at least 2% of the reported well stimulation treatment chemicals for which chemical abstract service oral toxicity data could not be identified by the CCST.

Table 4.9-23: CCST (2014) Summary of Chemicals Used in California Well Stimulation (Hydraulic Fracturing and Acid Matrix) with Chemical Abstract Service Data Hydraulic Fracturing Chemicals

Chemical/Ingredient Name	CAS Number	Count of Occurrence in Hydraulic Fracturing Fluid	% Occurrence in Fracturing Fluid	Count of Occurrence as Additive	Average Conc. in Fracturing Fluid (% mass)	Average Additive Conc. (% mass)	Oral Toxicity (LD50), Rat (mg/kg)	Oral Toxicity (LD50), Mouse (mg/kg)	Oral Toxicity (LD50), Rabbit (mg/kg)
Quartz (SiO2)	14808-60-7	1384	99.9	4032	23.988	34.1	500	Not Found	Not Found
Guar gum	9000-30-0	1334	96.2	1339	0.198	55.0	6770	8100	7000
Water	7732-18-5	1209	87.2	2047	73.879	94.2	>90000	Not Found	Not Found
Diammonium peroxodisulphate	7727-54-0	1182	85.3	1205	0.012	88.0	495-820	Not Found	Not Found
Sodium hydroxide	1310-73-2	1147	82.8	1148	0.010	10.8	140-340	Not Found	Not Found
Diatomaceous earth, calcined	91053-39-3	1068	77.1	1702	0.014	75.2	Not Found	Not Found	Not Found
Ethylene glycol	107-21-1	1052	75.9	1049	0.029	28.1	4700	7500	Not Found
Cristobalite	14464-46-1	1022	73.7	1022	0.009	1.1	Not Found	Not Found	Not Found
Magnesium nitrate	10377-60-3	1015	73.2	1015	0.000	9.8	5440	Not Found	Not Found
5-Chloro-2-methyl-3(2H)-isothiazolone	26172-55-4	1015	73.2	1015	0.000	9.8	481	Not Found	Not Found
2-Methyl-3(2H)-isothiazolone	2682-20-4	1015	73.2	1015	0.000	4.9	Not Found	Not Found	Not Found
Magnesium chloride	7786-30-3	1015	73.2	1015	0.000	4.9	2800	4700	Not Found
Isotridecanol, ethoxylated	9043-30-5	1014	73.2	959	0.016	5.0	Not Found	Not Found	Not Found
Distillates, petroleum, hydrotreated light	64742-47-8	1000	72.2	1003	0.097	30.2	>15000	Not Found	Not Found
Hemicellulase enzyme concentrate	9025-56-3	992	71.6	658	0.002	3.0	Not Found	Not Found	Not Found
Distillates, petroleum, hydrotreated light paraffinic	64742-55-8	973	70.2	-	0.098	30.4	>5000	Not Found	Found
2-butoxypropan-1-ol	15821-83-7	962	69.4	--	0.000	-	Not Found	Not Found	Not Found
1-butoxypropan-2-ol	5131-66-8	962	69.4	966	0.016	5.3	5.66mL/kg~4 920mg/kg	Not Found	Not Found
1,2-Ethanediaminium	138879-94-4	939	67.7	943	0.057	60.0	Not Found	Not Found	Not Found
Phosphonic acid	13598-36-2	680	49.1	680	0.000	1.0	1500-1895	1700-2172	Not Found
Boron sodium oxide	1330-43-4	676	48.8	677	0.030	27.6	2660	Not Found	Not Found
Methanol	67-56-1	368	26.6	485	0.068	52.5	5628 - 6970	7300	14400

Table 4.9-23: CCST (2014) Summary of Chemicals Used in California Well Stimulation (Hydraulic Fracturing and Acid Matrix) with Chemical Abstract Service Data Hydraulic Fracturing Chemicals

Chemical/Ingredient Name	CAS Number	Count of Occurrence in Hydraulic Fracturing Fluid	% Occurrence in Fracturing Fluid	Count of Occurrence as Additive	Average Conc. in Fracturing Fluid (% mass)	Average Additive Conc. (% mass)	Oral Toxicity (LD50), Rat (mg/kg)	Oral Toxicity (LD50), Mouse (mg/kg)	Oral Toxicity (LD50), Rabbit (mg/kg)
Borax	1303-96-4	364	26.3	364	0.033	25.3	5660	2000	Not Found
Carbonic acid, dipotassium salt	584-08-7	245	17.7	252	0.191	59.2	1870	2570	Not Found
Sodium chloride	7647-14-5	223	16.1	92	0.005	6.3	3000	4000	Not Found
Potassium hydroxide	1310-58-3	201	14.5	179	0.015	0.6	273 - 1230	Not Found	Not Found
Phenol, polymer with formaldehyde	9003-35-4	197	14.2	199	0.529	3.1	>5000	Not Found	Not Found
Glycerin, natural	56-81-5	160	11.5	108	0.037	0.2	5570-12600	4100	27000
Acetic acid	64-19-7	157	11.3	101	0.008	49.8	3310-3530	4960	1200
Silica	7631-86-9	149	10.8	139	0.174	1.7	>20000	Not Found	Not Found
Isopropanol	67-63-0	148	10.7	150	0.072	18.3	4710-5840	3600-4475	5030-7990
Alcohols, C11-14-iso-, C13-rich, ethoxylated	78330-21-9	114	8.2	109	0.003	0.0	Not Found	Not Found	Not Found
Naphthalene	91-20-3	114	8.2	76	0.001	0.8	490-2600	350 - 710	Not Found
Potassium chloride	7447-40-7	113	8.2	111	0.003	100.0	2600	383	Not Found
Talc	14807-96-6	109	7.9	109	0.000	0.0	Not Found	Not Found	Not Found
Tetrakis(hydroxymethyl)phosphonium sulfate	55566-30-8	109	7.9	109	0.003	0.0	248-333	Not Found	Not Found
Vinylidene chloride/methylacrylate copolymer	25038-72-6	105	7.6	105	0.004	0.0	Not Found	Not Found	Not Found
Alcohols, C7-9-iso-, C8-rich, ethoxylated	78330-19-5	103	7.4	103	0.056	0.2	Not Found	Not Found	Not Found
Ethoxylated C14-15 alcohols	68951-67-7	99	7.1	99	0.018	18.9	Not Found	Not Found	Not Found
Zirconium oxychloride	7699-43-6	94	6.8	94	0.017	0.1	2950-3500	1227	Not Found

Table 4.9-23: CCST (2014) Summary of Chemicals Used in California Well Stimulation (Hydraulic Fracturing and Acid Matrix) with Chemical Abstract Service Data Hydraulic Fracturing Chemicals

Chemical/Ingredient Name	CAS Number	Count of Occurrence in Hydraulic Fracturing Fluid	% Occurrence in Fracturing Fluid	Count of Occurrence as Additive	Average Conc. in Fracturing Fluid (% mass)	Average Additive Conc. (% mass)	Oral Toxicity (LD50), Rat (mg/kg)	Oral Toxicity (LD50), Mouse (mg/kg)	Oral Toxicity (LD50), Rabbit (mg/kg)
Glutaraldehyde	111-30-8	91	6.6	80	0.008	35.3	134-1470	100	1.59 ml/kg (50% aqueous solution) ~ 843 mg/kg
Methenamine	100-97-0	90	6.5	92	0.118	0.6	Not Found	569-1853	Not Found
Quaternary ammonium compounds, bis(hydrogenated tallow alkyl)dimethyl, salts with bentonite	68953-58-2	90	6.5	4	0.015	0.1	>8000	Not Found	Not Found
Solvent naphtha, petroleum, heavy arom.	64742-94-5	83	6.0	86	0.010	8.9	7050	Not Found	Not Found
Acetic anhydride	108-24-7	81	5.8	82	0.015	100.0	1780	Not Found	Not Found
Poly(oxy-1,2-ethanediyl), alpha-hexyl-omega-hydroxy	31726-34-8	81	5.8	81	0.017	0.1	Not Found	Not Found	Not Found
Glyoxal	107-22-2	79	5.7	80	0.065	30.0	200-7070	400-1280	>3175
D-Glucitol	50-70-4	79	5.7	80	0.022	10.0	15900	17800	Not Found
Monoethanolamine borate (1:x)	26038-87-9	78	5.6	78	0.041	60.0	Not Found	Not Found	Not Found
2,2-Dibromo-3-nitrilopropionamide	10222-01-2	77	5.6	77	0.004	100.0	178-235	Not Found	118
2-Bromo-3-nitrilopropionamide	1113-55-9	77	5.6	77	0.000	5.0	Not Found	Not Found	Not Found
Triethanolamine	102-71-6	74	5.3	74	0.042	0.2	4200-11300	5400-7800	2200
Boric acid	10043-35-3	70	5.1	71	0.016	30.0	2660-4000	3450	Not Found
Diethylene glycol	111-46-6	70	5.1	68	0.000	0.1	12565-16600	13300-26500	26900
Trimethyl borate	121-43-7	70	5.1	70	0.015	30.0	6140	1290	Not Found
Sodium persulfate	7775-27-1	70	5.1	70	0.005	100.0	Not Found	Not Found	Not Found
2-ethylhexan-1-ol	104-76-7	69	5.0	69	0.000	0.0	2049-3730	2500	1180-1470

Table 4.9-23: CCST (2014) Summary of Chemicals Used in California Well Stimulation (Hydraulic Fracturing and Acid Matrix) with Chemical Abstract Service Data Hydraulic Fracturing Chemicals

Chemical/Ingredient Name	CAS Number	Count of Occurrence in Hydraulic Fracturing Fluid	% Occurrence in Fracturing Fluid	Count of Occurrence as Additive	Average Conc. in Fracturing Fluid (% mass)	Average Additive Conc. (% mass)	Oral Toxicity (LD50), Rat (mg/kg)	Oral Toxicity (LD50), Mouse (mg/kg)	Oral Toxicity (LD50), Rabbit (mg/kg)
Oleic acid	112-80-1	69	5.0	69	0.000	0.0	25000-74000	28000	Not Found
Potassium acetate	127-08-2	69	5.0	68	0.000	0.0	3250	Not Found	Not Found
Potassium cis-9-octadecenoic acid	143-18-0	69	5.0	69	0.000	0.0	>5000	>5000	Not Found
Propylene glycol	57-55-6	69	5.0	69	0.000	0.0	20000-37000	22000-31800	18000-19000
Bis(2-ethylhexyl) sodium sulfosuccinate	577-11-7	69	5.0	69	0.001	0.0	1900-4620	2640	Not Found
Dicoco dimethyl ammonium chloride	61789-77-3	69	5.0	69	0.001	0.0	960	Not Found	Not Found
Alcohols, C10-14, ethoxylated	66455-15-0	69	5.0	69	0.002	0.0	Not Found	Not Found	Not Found
Phenol, 4,4'-(1-methylethylidene)bis-, polymer with 2- (chloromethyl)oxirane, 2-methyloxirane and oxirane	68123-18-2	69	5.0	69	0.007	0.0	Not Found	Not Found	Not Found
Poloxalene	9003-11-6	69	5.0	69	0.002	0.0	5700	3000-45000	Not Found
Calcium chloride anhydrous	10043-52-4	68	4.9	66	0.001	0.0	1000-4179	1940-2045	100-1000
2-Propenoic acid, polymer with sodium phosphinate (1:1), sodium salt	129898-01-7	66	4.8	66	0.011	0.1	Not Found	Not Found	Not Found
2-Butoxyethanol	111-76-2	62	4.5	32	0.028	40.9	470-3000	1200-1519	320
Acetyltriethyl citrate	77-89-4	59	4.3		0.024		7000	1150	Not Found
Citric acid	77-92-9	56	4.0	58	0.022	60.9	3000- 6730	5040	7000
Boric acid, dipotassium salt	1332-77-0	53	3.8	53	0.099	0.4	Not Found	Not Found	Not Found
Tryptones	73049-73-7	47	3.4	6	0.002	5.0	Not Found	Not Found	Not Found
Extract of yeast	08013-01-2	47	3.4	6	0.002	5.0	Not Found	Not Found	Not Found
Teflon	9002-84-0	47	3.4	47	0.000	0.0	Not Found	Not Found	Not Found
Polyethylene glycol	25322-68-3	44	3.2	44	0.001	0.0	600-51310	28915-36000	14000-76000

Table 4.9-23: CCST (2014) Summary of Chemicals Used in California Well Stimulation (Hydraulic Fracturing and Acid Matrix) with Chemical Abstract Service Data Hydraulic Fracturing Chemicals

Chemical/Ingredient Name	CAS Number	Count of Occurrence in Hydraulic Fracturing Fluid	% Occurrence in Fracturing Fluid	Count of Occurrence as Additive	Average Conc. in Fracturing Fluid (% mass)	Average Additive Conc. (% mass)	Oral Toxicity (LD50), Rat (mg/kg)	Oral Toxicity (LD50), Mouse (mg/kg)	Oral Toxicity (LD50), Rabbit (mg/kg)
Formaldehyde, polymer with 4-nonylphenol and oxirane	30846-35-6	44	3.2	44	0.005	0.0	Not Found	Not Found	Not Found
Quaternary ammonium compounds, benzyl-C10- 16alkyldimethyl, chlorides	68989-00-4	44	3.2	44	0.003	0.0	400-900	Not Found	Not Found
Alcohols, C9-11-iso-, C10-rich, ethoxylated	78330-20-8	44	3.2	44	0.006	0.0	Not Found	Not Found	Not Found
Cellulase	9012-54-8	44	3.2	58	0.008	21.2	Not Found	Not Found	Not Found
Sodium sulfate	7757-82-6	43	3.1		0.001		5989	193-6346	Not Found
Naphtha, petroleum, hydrotreated heavy	64742-48-9	42	3.0	42	0.304	60.0	>15000	Not Found	Not Found
Mannanase, endo-1,4-beta-	37288-54-3	41	3.0	-	0.001	-	Not Found	Not Found	Not Found
Ampicillin	69-53-4	41	3.0	-	0.001	-	10000	15200	Not Found
Cellulose, microcrystalline	9004-34-6	41	3.0	-	0.001	-	>5000	Not Found	Not Found
Ethanol	64-17-5	39	2.8	41	0.031	27.7	7060-10600	3450	63000
Hydrogen peroxide	7722-84-1	39	2.8	39	0.000	0.3	376-1617	2000	820
Decyldimethylamine	1120-24-7	38	2.7	38	0.000	0.0	Not Found	Not Found	Not Found
N,N-Dimethyldecylamine oxide	2605-79-0	38	2.7	38	0.020	0.1	Not Found	Not Found	Not Found
Ammonium chloride	12125-02-9	37	2.7	30	0.061	50.3	1650	1300	Not Found
Solvent naphtha, petroleum, light arom.	64742-95-6	33	2.4	33	0.012	16.8	3500-14000	Not Found	Not Found
Hydrogen chloride	7647-01-0	33	2.4	46	0.799	22.5	238-277	Not Found	900
Sodium bicarbonate	144-55-8	32	2.3	-	0.065	-	4220	3360	Not Found
Poly(oxy-1,2-ethanediyl), alpha-tridecyl-omega-hydroxy	24938-91-8	31	2.2	-	-	-	Not Found	Not Found	Not Found

Table 4.9-23: CCST (2014) Summary of Chemicals Used in California Well Stimulation (Hydraulic Fracturing and Acid Matrix) with Chemical Abstract Service Data Hydraulic Fracturing Chemicals

Chemical/Ingredient Name	CAS Number	Count of Occurrence in Hydraulic Fracturing Fluid	% Occurrence in Fracturing Fluid	Count of Occurrence as Additive	Average Conc. in Fracturing Fluid (% mass)	Average Additive Conc. (% mass)	Oral Toxicity (LD50), Rat (mg/kg)	Oral Toxicity (LD50), Mouse (mg/kg)	Oral Toxicity (LD50), Rabbit (mg/kg)
1,2,4-Trimethylbenzene	95-63-6	31	2.2	33	0.001	2.8	3280-6000	Not Found	Not Found
Propargyl alcohol	107-19-7	29	2.1	31	0.001	7.7	20 -110	50	Not Found
Thiourea, polymer with formaldehyde and 1-phenylethanone	68527-49-1	29	2.1	20	0.003	19.5	Not Found	Not Found	Not Found

Oral Toxicity: LD50 (mgchemical/kganimal)
Category 1: x<5
Category 2: 5<x<50
Category 3: 50<x<300
Category 4: 300<x<2000
Category 5: 2000<x<5000
Category >5: x>5000

Table 4.9-23 (Continued) Acid Matrix Chemicals

Chemical/Ingredient Name	CAS Number	# of Wells	% of Wells	Oral Toxicity (LD_{50}), Rat (mg/kg)	Oral Toxicity (LD_{50}), Mouse (mg/kg)	Oral Toxicity (LD_{50}), Rabbit (mg/kg)
2-Ethylhexanol	104-76-7	36	100%	2049-3730	2500	1180-1470
Ethylene glycol	107-21-1	36	100%	4200	7500	Not Found
2-butoxyethanol	111-76-2	36	100%	470-3000	1200-1519	320
Dodecylbenzene sulfonic acid	27176-87-0	36	100%	500-2000	Not Found	Not Found
Methanol	67-56-1	36	100%	5628-6970	7300	14400
Isopropanol	67-63-0	36	100%	4710-5840	3600-4475	5030-7990
Hydrochloric Acid	7647-01-0	36	100%	238-277	Not Found	900
Water	7732-18-5	36	100%	>900000	Not Found	Not Found
Poly(oxy-1,2-ethanediyl), alpha-hexyl-omega-hydroxy(C2H4O)n(c6H140) or Polyethylene glycol monohexyl ether	31726-34-8	36	100%	Not Found	Not Found	Not Found
Acetic acid	64-19-7	29	81%	3310-3530	4960	1200
Benzaldehyde	100-52-7	19	53%	800-1600	28-1600	Not Found
Cinnamaldehyde	104-55-2	19	53%	2220-3400	200-3400	Not Found
Diethylene glycol	111-46-6	19	53%	12565-16600	13300-26500	26900
Ammonium bifluoride	1341-49-7	19	53%	130	Not Found	Not Found
Hydroxylamine hydrochloride	5470-11-1	19	53%	141	408	Not Found
Amine oxides, cocoalkyldimethyl	61788-90-7	19	53%	Not Found	Not Found	Not Found
Formic Acid	64-18-6	19	53%	1100	700	Not Found
Ethoxylated hexanol	66439-45-2	19	53%	Not Found	Not Found	Not Found
Alcohols, C12-16, ethoxylated	68551-12-2	19	53%	Not Found	Not Found	Not Found
Copper dichloride	7447-39-4	19	53%	140-584	190-233	Not Found
Ethylene oxide	75-21-8	19	53%	72-330	280-365	Not Found

Table 4.9-23 (Continued) Acid Matrix Chemicals

Chemical/Ingredient Name	CAS Number	# of Wells	% of Wells	Oral Toxicity (LD_{50}), Rat (mg/kg)	Oral Toxicity (LD_{50}), Mouse (mg/kg)	Oral Toxicity (LD_{50}), Rabbit (mg/kg)
Slica, amorphous – fumed	7631-86-9	19	53%	>20000	Not Found	Not Found
Sodium iodide	7681-82-5	19	53%	4340	1000	Not Found
Citric Acid	77-92-9	19	53%	3000-5730	5040	7000
Poly(oxy-1,2-ethanediyl), a(mony phenyl)-w-hydroxy	9016-45-9	19	53%	1310-16000	>50000	Not Found
Magnesium nitrate	10377-60-3	17	47%	5440	Not Found	Not Found
Prop-2-yn-1-ol	107-19-7	17	47%	20-110	50	Not Found
Oleic acid	112-80-1	17	47%	25000-74000	28000	Not Found
Dodecylbenzene (impunity)	123-01-3	17	47%	>5000	Not Found	Not Found
Linear/branched alcohol ethoxylate (11eo)	127036-24-2	17	47%	Not Found	Not Found	Not Found
Acetic acid, potassium salt	127-08-2	17	47%	3250	Not Found	Not Found
Sodium hydroxide	1310-73-2	17	47%	140-340	Not Found	Not Found
Disodium ethylene diamine tetra-acetate (impurity)	139-33-3	17	47%	2000-3700	400-2050	2300
Potassium oleate	143-18-0	17	47%	>5000	>5000	Not Found
Cristobalite	14464-46-1	17	47%	Not Found	Not Found	Not Found
Crystalline silica	14808-60-7	17	47%	500	Not Found	Not Found
Trisodium ethylene diaminetetracetate (Impurity)	150-38-9	17	47%	2150	2150	Not Found
Pol(oxy-1,2-ethanediyl)	25322-68-3	17	47%	600-51310	28915-36000	14000-76000
5-chloro-2-methyl-2h-isothiazolol-3-one	26172-55-4	17	47%	481	Not Found	Not Found
2-methyl-2h-isothiazol-3-one	2682-20-4	17	47%	Not Found	Not Found	Not Found
Sodium glycolate (impurity)	2836-32-0	17	47%	7110	6700	Not Found
Ethoxylated propoxylated 4-nonylphenol-formaldehyde resin	30846-35-6	17	47%	Not Found	Not Found	Not Found
Alcohol, C11 linear, ethoxylated	34398-01-1	17	47%	Not Found	Not Found	Not Found
Trisodium nitrilotiacetate (impurity)	5064-31-3	17	47%	1100-3500	681-3160	>3500

Table 4.9-23 (Continued) Acid Matrix Chemicals

Chemical/Ingredient Name	CAS Number	# of Wells	% of Wells	Oral Toxicity (LD_{50}), Rat (mg/kg)	Oral Toxicity (LD_{50}), Mouse (mg/kg)	Oral Toxicity (LD_{50}), Rabbit (mg/kg)
Glycerol	5681-5	17	47%	5570-12600	4100	27000
Propylene glycol	57-55-6	17	47%	20000-37000	22000-31800	18000-19000
Dioctyl sulfosuccinate sodium salt	577-11-7	17	47%	1900-4620	2640	Not Found
Dicoco dimethyl quatetnary ammonium chloride	61789-77-3	17	47%	960	Not Found	Not Found
Fatty acids, tall–oil	61790-12-3	17	47%	3200-74000	4600	Not Found
Sodium erythorbate	6381-77-7	17	47%	>5000	Not Found	Not Found
Tetrasodium ethylenediaminetetraacetate	64-02-8	17	47%	1658-4500	20-5-30	Not Found
Heavy aromatic naphtha	64742-94-5	17	47%	7050	Not Found	Not Found
Alkenes, C>10a-	64743-02-8	17	47%	Not Found	Not Found	Not Found
Alkyl (C10-C14) alcohols, ethoxylated	66455-15-0	17	47%	Not Found	Not Found	Not Found
Crosslinked PO/EO-block polymer	68123-18-2	17	47%	Not Found	Not Found	Not Found
Coco-amido-propylamine oxide	68155-09-9	17	47%	Not Found	Not Found	Not Found
Alcohol C9-C11, Ethoxylated	68439-46-3	17	47%	1378	Not Found	Not Found
Thiurea, polymer with formaldehyde and 1-phenylethanone	68527-49-1	17	47%	Not Found	Not Found	Not Found
Alcohols, C14-15, ethoxylated (7ED)	68951-67-7	17	47%	Not Found	Not Found	Not Found
Quaternary ammonium compounds chlorides derivatives	68989-00-4	17	47%	400-900	Not Found	Not Found
Hydrofluoric acid	7664-39-3	17	47%	Not Found	Not Found	Not Found
Sulfuric acid (impurity)	7664-93-9	17	47%	2140	Not Found	Not Found
Magnesium chloride	7786-30-3	17	47%	2800	4700	Not Found
Alcohol, C7-9-iso, C8, ethoxylated	78330-19-5	17	47%	Not Found	Not Found	Not Found
Alcohol, C9-11-iso, C10, ethoxylated	78330-20-8	17	47%	Not Found	Not Found	Not Found
Alcohol, C11-14, ethoxylated	78330-21-9	17	47%	Not Found	Not Found	Not Found
Methyl oxirane polymer with oxirane	9003-11-6	17	47%	2300-5700	1830-45000	35000

Table 4.9-23 (Continued) Acid Matrix Chemicals

Chemical/Ingredient Name	CAS Number	# of Wells	% of Wells	Oral Toxicity (LD_{50}), Rat (mg/kg)	Oral Toxicity (LD_{50}), Mouse (mg/kg)	Oral Toxicity (LD_{50}), Rabbit (mg/kg)
Diatomaceous earth, calcined	91053-39-3	17	47%	Not Found	Not Found	Not Found
Naphthalene (impurity)	91-20-3	17	47%	490-2600	350-710	Not Found
Ammonium chloride	12125-02-9	1	3%	1650	1300	Not Found

Oral Toxicity: LD50 (mgchemical/kganimal)
Category 1: x<5
Category 2: 5<x<50
Category 3: 50<x<300
Category 4: 300<x<2000
Category 5: 2000<x<5000
Category >5: x>5000

Key:
CAS = chemical abstract service
LD_{50} = median lethal dose
mg/kg = milligram per kilogram

Table 4.9-24: CCST (2014) Summary of Chemicals Used in California Well Stimulation without Chemical Abstract Service Data

	Occurrence in Hydraulic Fracturing Fluid	% Occurrence in Fracturing Fluid	Count of Occurrence as Additive	Average Conc. In Fracturing Fluid (% mass)	Average Additive Conc. (% mass)
Amino Alkyl Phosphonic Acid	679	49	679	0.006	30
Contains non-hazardous ingredients which are listed in the non-MS DS section of the report	253	18.3	182	0.068	100
No Hazardous Ingredients	135	9.7	136	0.048	100
Water (Including Mix Water Supplied by Client)	131	9.5	n/a	74.68	n/a
Petroleum Distillate Blend	127	9.2	127	0.549	70
Hemicellulase Enzyme	111	8	111	0.01	100
N.A.	89	6.4	89	0.069	100
Mixture of Surfactant	80	5.8	80	0.081	60
EDTA/Copper chelate	62	4.5	62	0.008	30
Carbohydrates	44	3.2	58	0.035	97.1
Non-hazardous Ingredients	41	3	41	0.067	100
Cured Acrylic Resin	38	2.7	n/a	0.001	n/a
Alkanes /Alkenes	33	2.4	33	0.291	45
Proprietary	33	2.4	33	0.03	61.2
Sulfonate	29	2.1	29	0.007	9.8
Ethoxylated nonylphenol	28	2	38	0.104	35.8
Non-Hazardous Ingredient	28	2	31	0.04	100

Key:
% = percent

The BLM study reached 11 conclusions regarding well stimulation activities in California:

1. Present-day well stimulation practices in California differ significantly from practices used for unconventional shale reservoirs in states such as North Dakota and Texas, and the impacts of hydraulic fracturing observed in other states are not necessarily applicable to California.

2. Acid fracturing has comprised a small fraction of reported well stimulation to date in California, is usually applied in relatively rare carbonate reservoirs, and is not expected to lead to major increases in oil and gas development in the state.
3. The most likely scenario for expanded well stimulation in California is production in and near reservoirs that are currently using well stimulation and that contain oil migrated from source rocks and not from the Monterey Formation shales.
4. Current water demand for well stimulation operations is a small fraction of statewide water use and ranges from 450 to 1,200 AF per year. Ninety-five percent of water currently used for well stimulation is fresh water; the remainder is produced water, and most of the demand occurs in the southwestern San Joaquin Valley.
5. Most chemicals used in reported well stimulation treatments for which toxicity information is available are considered to be of low toxicity or nontoxic. However, a few reported chemicals present concerns for acute toxicity, including biocides and mineral acids. Potential risks posed by chronic exposure to most chemicals used in well stimulation activities remain unknown.
6. There are no publicly recorded instances of subsurface release of contaminated fluids into potable groundwater in California; additional studies and data collection are needed to fully evaluate this potential concern.
7. Current well stimulation practices could allow flowback water containing stimulation chemicals to be mixed with produced water for use in irrigation.
8. Estimated marginal criteria air emissions (e.g., NOx, $PM_{2.5}$, and VOCs [see Section 4.3, Air Quality]) directly related to well stimulation are a small portion of the overall emissions in the San Joaquin Valley, where the vast majority of hydraulic fracturing takes place.
9. Fugitive methane emissions from direct well stimulation in oil wells are likely to be small compared to the total greenhouse gas emissions from oil and gas production in California.
10. Current hydraulic fracturing for oil and gas production in California is not considered to pose a significant seismic hazard. The disposal of produced water from oil and gas production in deep injection wells has caused felt seismic events in several states and could increase seismic hazards in California under certain conditions if similar deep disposal wells were permitted.
11. Overall, the direct impacts of current well stimulation practices appear to be limited and will likely be limited in the future if proper management practices are followed. Existing or as yet unidentified technologies might be developed to extract oil and gas from new

locations, such as the Monterey Formation, and could generate different environmental impacts compared with the impacts associated with current well stimulation activities.

In 2015, Kennedy-Jenks (see Appendix S-1 in the 2015 FEIR) analyzed the chemicals reported in hydraulic fracturing and acid matrix well stimulation interim notices compiled by CalGEM (then DOGGR) through March 2014. Table 4.9-25 summarizes the chemicals and estimated concentrations of each constituent identified in the hydraulic fracturing well stimulation notices. Table 4.9-26 summarizes the chemicals and estimated concentrations of each constituent identified in the acid matrix well stimulation notices.

Table 4.9-25: Representative Chemicals Listed in Hydraulic Fracturing Notices Through March 2014

Ingredients[(a)]	Chemical Abstract Service	Estimated Ingredient Concentration in Fluid (% by mass)[(b)]
Water	7732-18-5	55.41%
Crystalline Silica	14808-60-7	41.80%
Guar Gum	9000-30-0	0.4387%
Petroleum Distillates	64742-47-8	0.2193%
Paraffinic Petroleum Distillates	64742-55-8	0.2193%
Isotridecanol, ethoxylated	9043-30-5	0.0366%
1-buloxy-2-propanol	5131-66-8	0.0366%
Crystalline Silica-Quartz	14808-60-7	0.0366%
Hemicellulase Enzyme Concentrate	9025-56-3	0.0021%
Sodium Tetraborate Decahydrate	1303-96-4	0.0732%
Ethylene Glycol	107-21-1	0.0732%
Sodium Hydroxide	1310-73-2	0.0244%
Oxyakylated Amine Quat	138879-94-4	0.397%
Ammonium persulphate	7727-54-0	0.0083%
Diatomaceous Earth, Calcined	91053-39-3	0.01%
5-Chloro-2-Methyl-4-Isothiazolin-3-One	26172-55-4	0.0020%
Magensium Nitrate	10377-60-3	0.0020%
Magensium Chloride	7786-30-3	0.001%
2-Methyl-4-Isothiazolin-3-One	2682-20-4	0.001%
Crystalline Silica: Cristobalite	14464-46-1	0.0002%
Crystalline Silica: Quartz (SiO2)	14808-60-7	0.0002%
Citric Acid	77-92-9	0.109049%

Table 4.9-25: Representative Chemicals Listed in Hydraulic Fracturing Notices Through March 2014

Ingredients[a]	Chemical Abstract Service	Estimated Ingredient Concentration in Fluid (% by mass)[b]
Ethylene glycol monobutyl ether	111-76-2	0.060756%
Xylene	1330-20-7	0.357930%
Ethyl Benzene	100-41-4	0.107938%
Hydrochloric Acid	7647-01-0	0.576579%
Hydrogen fluroide (hydrofluoric acid)	7664-39-3	0.27228%
Formic Acid	64-18-6	0.10553%
Carboxylic Acid Salt	127-08-2	0.00009%
Methanol	67-56-1	0.003482%
Morpholine	110-91-8	0.000769%
Organic Acid	64-19-7	0.000006%
Organic sulfonic acid amine salt	12068-08-5	0.030652%
Oxyalkylated Alcohole	66455-15-0	0.025637%
Isopropanol	67-63-0	0.013346%
Oxyakylated alkylphenolic resin	63428-92-2	0.005358%
Polyoxyalkylenes	68439-45-2	0.001076%
Light aromatic naphtha	64742-95-6	0.000837%
1,2,4-TMB	95-63-6	0.000544%
1,3,5-TMB	108-67-8	0.00017%
1,2,3-TMB	526-73-8	0.000085%
Xylene	1330-20-7	0.000043%
Alkylaryl sulfonate	68584-27-0	0.000034%
Cumene	98-82-8	0.000019%
Potassium hydroxide	1310-58-3	0.000011%
Cocamidopropyl betaine	61789-40-0	Not Reported
Caprylamidopropyl betaine	73772-46-0	Not Reported Sodium
Chloride	7647-14-5	Not Reported
Glycerol	56-81-5	Not Reported
Isotridecanol, ethoxylated	9043-30-5	0.016542%
1-Butoxy-2-Propanol	5131-66-8	0.016542%
2-Butoxy -1-Propanol	15821-83-7	0.000331%

Table 4.9-25: Representative Chemicals Listed in Hydraulic Fracturing Notices Through March 2014

Ingredients[a]	Chemical Abstract Service	Estimated Ingredient Concentration in Fluid (% by mass)[b]
Potassium carbonate	584-08-7	0.144146%
Potassium Bicarbonate	298-14-6	0.004805%
Methyl Borate	121-43-7	0.010093%
Boric Acid	10043-35-3	0.010093%
Ammonium chloride	12125-02-9	0.087395%
Erythorbic Acid	89-65-6	0.610957%
Phenolic resin	9003-35-7	0.16499%
Potassium borate	1332-77-0	0.06493%
2,2,2''-nitrilotriethanol	102-71-6	0.03495%
Zirconium dichlooride oxide	7699-43-6	0.01888%
Polyethylene glycol monhexyl ether	31726-34-8	0.01575%
Alcohol, C7-9-iso, C8, ethoxylated	78330-19-5	0.01404%
2-Propenoic acid, polymer with sodium phosphinate	129898-01-7	0.00864%
Crosslinked PO/EO-block polymer	68123-18-2	0.00615%
Vinylidene chloride/methylacrylate copolymer	25038-72-6	0.0047%
Non-crystalline silica	7631-86-9	0.00245%
Alcohol, C11-14, ethoxylated	78330-21-9	0.00204%
Tetrakis(hydroxymethyl)phosphonium sulfate	55566-30-8	0.00203%
Methyl oxirane polymer with oxirane	9003-11-6	0.00203%
Dioctyl sulfosuccinate sodium salt	577-11-7	0.00096%
Calcium chloride	10043-52-4	0.00082%
Dicoco dimethyl quaternary ammonium chloride	61789-77-3	0.00069%
Magnesium silicate hydrate (talc)	14807-96-6	0.00025%
Propylene glycol	57-55-6	0.0002%
2,2'-oxydiethanol	111-46-6	0.00009%
2-ethylhexan-1-ol	104-76-7	0.00003%
Potassium oleate	143-18-0	0.00001%

Table 4.9-25: Representative Chemicals Listed in Hydraulic Fracturing Notices Through March 2014

Ingredients[a]	**Chemical Abstract Service**	**Estimated Ingredient Concentration in Fluid (% by mass)[b]**
Oleic acid	112-80-1	0.00001%
Alcohols, C10-12, ethoxylated	67254-71-1	0.00155%
Monoethanolamine borate	26038-87-9	0.09738%
2,2 Dibromo-3-nitrilopropionamide	10222-01-2	0.00122%
2-Monobromo-3-nitrilopropionamide Bentonite, benyzl(hydrogenated tallow alkyl)	1113-55-9	0.00006%
Dimethylammonium stearate complex	121888-68-4	0.00773%
Sodium Persulfate	7775-27-1	0.00782%
disodium octaborate tetrahydrate	12008-41-2	0.1623%
Sodium polyacrylate	9003-04-7	0.15451%
Sodium bisulfite	7631-90-5	0.00097%
Hemicellulase enzyme	9012-54-8	0.00315%
Lactose	63-42-3	0.01051%
Polydimethyl diallyl ammonium chloride	26062-79-3	0.07228%
Polyethelene glycol oleate ester	56449-46-8	0.00155%
Silica gel	112926-00-8	0.00155%
Sodium sulfate	7757-82-6	0.00001%

Source: Appendix S-1, 2015 FEIR
Notes:
[a] Chemicals lists were observed on CalGEM (the DOGGR) Interim Well Stimulation Notices, accessed March 13, 2014. This listing shows chemicals found in a sampling of hydraulic fracture notices from different fields. A chemical is only listed once, even if it shown on multiple notices.
[b] The estimated concentration listed is representative of a "typical" use, based on the information reviewed, and will vary between wells.

Table 4.9-26: Representative Chemicals Listed in Acid Matrix Notices

Ingredients[(a)]	CAS	Max Ingredient Concentration in Fluid (% by mass)[(b)]
Fresh water	7732-18-5	44.83%
Acetic acid	64-19-7	1.63806%
Citric acid	77-92-9	1.38132%
Hydrochloric acid	7647-01-0	25.5402%
Methanol	67-56-1	0.2650%
Diethylene glycol	111-46-6	0.5226%
Cinnamaldehyde	104-55-2	0.5226%
Formic acid	64-18-6	0.8317%
Isopropanol	67-63-0	0.2678%
Dodecylbenzene sulfonic acid	27176-87-0	0.4780%
Isopropanol	67-63-0	0.1434%
Ethylene glycol monobutyl ether	111-76-2	1.6826%
Ethoxylated hexanol	68439-45-2	0.5048%
Ethylene glycol monobutyl ether	111-76-2	0.5282%
Ethylene glycol	107-21-1	0.0440%
Poly(oxy-12-ethandiyl) a-(nonylphenyl)-w-hydroxy-	9016-45-9	0.0880%
2-Ethyl hexanol	104-76-7	Not Reported
Alcohols C12-16 ethoxylated		68551-12-2
Not Reported Amine oxides cocoalkyldimethyl	61788-90-7	Not Reported
Benzaldehyde	100-52-7	Not Reported
Copper dichloride	7447-39-4	Not Reported
Ethylene oxide	75-21-8	Not Reported
Methanol	67-56-1	Not Reported
Poly(oxy-1,2-ethanediyl); alpha-hexyl-omega-hydroxy(C2H4O)N(C6H14O)	31726-34-8	Not Reported
Sodium iodide	7681-82-5	Not Reported
Ammonium bifluoride	1341-49-7	2.21%
Hydroxylamine hydrochloride	5470-11-01	0.07%
Silica amorphous fumed	7631-86-9	0.01%
Hydrofluoric acid	7664-39-3	<1%
Tetrasodium Ethylenediaminetetraacetate	64-2-8	<0.1%

Table 4.9-26: Representative Chemicals Listed in Acid Matrix Notices

Ingredients[(a)]	CAS	Max Ingredient Concentration in Fluid (% by mass)[(b)]
Sodium Erythorbate	6381-77-7	<0.1%
Fatty acids, tall-oil	61790-12-3	<0.1%
Thiourea, polymer with formaldehyde and 1-Phenylethanone	68527-49-1	<0.1%
Linear/branched alcohol ethoxylate	127036-24-2	<0.1%
Alcohols, C14-15, ethoxylated	68951-67-7	<0.1%
Prop-2-yn-1-ol	107-19-7	<0.1%
Sodium glycolate	2836-32-0	<0.01%
Alkenes	64743-02-8	<0.01%
Alcohols, C11-14-iso, ethoxylated	78330-20-8	<0.01%
Alcohols, C7-9-iso, ethoxylated	78330-19-5	<0.01%
Glycerol	56-81-5	<0.01%
Ethoxylated resin	30846-35-6	<0.01%
Alcohol, C11-14, ethoxylated	78330-21-9	<0.01%
Crosslinked PO/EO Polymer	68123-18-2	<0.01%
Alcohol, C11 linear	34398-01-1	<0.01%
Heavy aromatic naphtha	64742-94-5	<0.01%
Quaternary ammonium compounds	68989-00-4	<0.01%
Sodium hydroxide	1310-73-2	<0.01%
Disodium Ethylene Diamine tetra acetate (impurity)	139-33-3	<0.01%
Trisodium Ethylene Diamine tetra acetate (impurity)	150-38-9	<0.01%
Alcohol, C9-C11, ehoxylated	68949-46-3	<0.01%
Alkyl (c10-c14) alcohols, ethoxylated	66455-15-0	<0.01%
Methyl oxirane polymer	9003-11-6	<0.01%
Poly(oxy-1,2-ethaediyl)	25322-68-3	<0.01%
Trisodium nitrilotriacetate (impurity)	5064-31-3	<0.01%
Coco-amido-proplyamine oxide	68155-09-9	<0.01%
Diatomaceous earth, calcined	91053-39-3	<0.001%
Dicoco dimethyl quaternary ammonium chloride	61789-77-3	<0.001%
Dioctyl sulfosuccinate sodium salt	577-11-7	<0.001%
Naphthale (impurity)	91-20-3	<0.001%

Table 4.9-26: Representative Chemicals Listed in Acid Matrix Notices

Ingredients[a]	**CAS**	**Max Ingredient Concentration in Fluid (% by mass)[b]**
Dodecyl benzene	123-01-3	<0.001%
Sulfuric acid (impurity)	7664-93-9	<0.001%
Magnesium nitrate	10377-60-3	<0.001%
Propylene glycol	57-55-6	<0.001%
5-chloro2-2methyl-2h-isothiazol-3-one	26172-55-4	<0.001%
Magnesium chloride	7786-30-3	<0.0001%
2-ethylhexan-1-ol	2682-20-4	<0.0001%
Crystalline silica	14808-60-7	<0.0001%
Cristobalite	14464-46-1	<0.0001%

Source: 2015 FEIR Appendix S-1
Notes:

[a] Chemicals lists were observed on CALGEM Interim Well Stimulation Notices, accessed March 13, 2014. This listing shows chemicals found in a sampling of hydraulic fracture notices from different fields. A chemical is only listed once, even if it shown on multiple notices.

[b] The estimated concentration listed is representative of a "typical" use, based on the information reviewed, and will vary between wells.

California has enacted several new laws pertaining to well stimulation, including significantly expanded pre- and post-treatment notice and disclosure requirements under SB 4. The notices and disclosures must include estimates of total water use by source, the types and amounts of chemicals used in each treatment, and an analysis of constituent levels in treatment flowback water recovered at the well head. In February 2015, the *Los Angeles Times* reported that high levels of benzene had been detected in produced water samples, based on flowback water test results reported in publicly available well stimulation notices and disclosures submitted to CALGEM (Cart 2015b). A 1993 CalGEM (then DOGGR) study of benzene in produced water generated by oil and gas activities in Kern County found that hydrocarbon-bearing formations contain benzene and that the benzene concentrations tend to increase with the incidence of heavier (lower American Petroleum Institute gravity) oil deposits (Gamache 1993). A 2012 USGS study of geogenic sources of benzene in aquifers used for public supply generally concluded that benzene levels in state drinking water were low and that benzene occurs in groundwater mainly from geological factors, including proximity to hydrocarbon bearing formations (Landon and Belitz 2012). As shown in Table 4.9-21, and consistent with the USGS and CalGEM studies, benzene has been detected in produced water drawn from hydrocarbon bearing formations.

Floodplains and Drainages

A Federal Insurance Rate Map (FIRM) was developed by the Federal Emergency Management Agency (FEMA) for Kern County, California (unincorporated areas). The map identifies locations in the Project Area that are subject to a 100-year flood hazard risk, or inundation from flooding at least once over 100 years. Figure 4.9-17 shows the locations that are subject to a 100-year flood hazard risk and to undetermined but potential risks of flooding within the Project Area. Mapped and potential flood risk areas overlie several existing oil fields.

Portions of the Project Area could also be subject to inundation by upstream dam failures, particularly the potential failure of Lake Isabella dam. Lake Isabella is 35 miles northeast of Bakersfield. Lake Isabella was created by a dam completed by the USACE in 1953. The Lake Isabella dam consists of a main dam and an auxiliary dam, which are located 2,000 feet laterally apart. The main earthfill dam is 185 feet high and 1,725 feet long, while the auxiliary earthfill structure is 100 feet high and 3,275 feet long. The gross capacity of both dams is 568,100 AF. The dam facilities have been determined to be substandard by the USACE, and a safety modernization program has been implemented to upgrade the dam by 2022. During the review process, the USACE prepared flood inundation maps identifying the potential inundation area and time-step of flood arrival, assuming both a full reservoir and complete failure of both dams (Kern County n.d.). Figure 4.9-18 shows the potential peak elevation inundation depths that could occur from a dam failure under these highly conservative assumptions within the Project Area.

Additional information concerning Project Area drainages and wetland resources, and maps showing the locations of these resources in each Subarea, are provided in Section 4.4, Biological Resources, of the 2015 FEIR.

4.9.3 Regulatory Setting

Federal

Clean Water Act (33 U.S.C. §1321 et seq.)

The 1972 Federal Water Pollution Control Act and its 1977 amendments, collectively known as the Clean Water Act (CWA), established national water quality goals and the basic structure for regulating discharges of pollutants into the waters of the United States. Section 402 of the CWA establishes NPDES to regulate the discharge of pollutants into waters of the United States. Section 404 of the CWA regulates the discharge of fill or dredged materials to waters of the United States (see Section 4.4, Biological Resources in the 2015 FEIR). Section 404 is jointly implemented by EPA and the USACE, both of which are responsible for onsite investigations and enforcement of unpermitted discharges (EPA 2020). Permits issued under the CWA limit the composition and, in some cases, the volume of a discharge and the concentrations of individual pollutants. Discharge requirements are based on available technology (technology-based effluent limits) and on the quality of the receiving waters (water quality-based effluent limits).

The CWA allows for the delegation of implementation authority to the states. Under the federal or delegated program, all the information required for permit application and monitoring for permit compliance are considered public, with the exception of certain confidential business information which may be considered trade secret. In addition, the program requires delegated states to establish water quality standards for specific water bodies and to designate the types of pollutants to be regulated, including total suspended solids and oil and grease. In California, NPDES permitting authority is delegated to the SWRCB and nine RWQCBs. The Project Area is within the jurisdiction of the CVRWQCB.

Under the NPDES program, all point sources that discharge directly into waters of the United States are required to obtain a permit regulating their discharge. Each NPDES permit specifies effluent limitations for particular pollutants as well as monitoring and reporting requirements for the proposed discharge. Construction activities in the Project Area that could result in a discharge to waters of the United States are subject to the California NPDES General Permit for Stormwater Associated with Construction Activities (Construction Activity NPDES Storm Water General Permit, 2009-0009-DWQ and 2010-0014-DWQ). Other stormwater discharges could be subject to the Industrial General Permit issued under the NPDES program, or to a municipal separate storm sewer system NPDES permit issued for municipal locations, or to individual NPDES permits issued to specific landowners or land use operators. More information about NPDES permits that apply to oil and gas operations is provided in the discussion of state permitting below.

Section 401 of the CWA requires that an applicant requesting a federal permit for an activity that may result in a discharge into a water of the United States obtain state certification that the proposed activity will not violate state and federal water quality standards. State water quality standards are discussed below. The CVRWQCB implements Section 401 of the CWA in the Project Area.

Total Maximum Daily Loads

Under section 303(d) of the CWA, states, territories, and authorized tribes are required to develop lists of impaired waters (i.e., waters that exceed applicable water quality standards). The law requires that these jurisdictions establish priority rankings for waters on the lists and develop total maximum daily loads (TMDL) for these waters. A TMDL is a calculation of the maximum amount of a pollutant that a waterbody can receive and still meet water quality standards.

On December 5, 2013, the EPA announced a new collaborative framework for implementing the CWA Section 303(d) Program with States — A Long-Term Vision for Assessment, Restoration, and Protection under the Clean Water Act Section 303(d) Program. This program reflects collaboration among states and the EPA, which began in August 2011. While the Vision provides a new framework for implementing the CWA 303(d) Program, it does not alter state and EPA responsibilities or authorities under the CWA 303(d) regulations. There are no impaired waters listed within the Project Area, and no TMDLs have been established for surface waters in the Project Area.

Other Clean Water Act Programs Related to Oil and Gas Production

Several federal programs and regulations have been implemented under the authority of the CWA to regulate oil and gas production activities that could affect surface water quality.

The Oil Pollution Act of 1990 (33 United States Code [U.S.C.] §2701-2761) amended the CWA and established a single uniform federal system of liability and compensation for damages caused by oil spills in navigable waters, which are defined as waters of the United States. The Act requires the removal of spilled oil and establishes a national system of planning for and responding to oil spill incidents, including: improved national oil-spill prevention, preparedness, and response capabilities; limitations on liability for damages resulting from oil pollution; funding for natural resource damage assessments; a fund for damage compensation payments; and the establishment of an oil pollution research and development program. Additionally, the Oil Pollution Act requires the development of Area Contingency plans to prepare and plan for oil spill response on a regional scale (EPA n.d. [a]).

Regulations promulgated under the Oil Pollution Act (40 CFR 112) require that a spill prevention control and countermeasures (SPCC) plan must be prepared for most facilities with a total aboveground oil storage capacity greater than 1,320 gallons or a total underground oil storage capacity of greater than 42,000 gallons. The purpose of an SPCC plan is to prevent oil from reaching waters of the United States and adjoining shorelines, and to contain discharges of oil. SPCC plans must be prepared and certified by a professional engineer and implemented for facilities that store, process, transfer, distribute, use, drill, produce, or refine oil or oil production. At a minimum, an SPCC plan must include (1) procedures and methods for proper installation of equipment to prevent an oil release; (2) a training and drill program for all personnel addressing oil spill response; and (3) a plan that outlines steps to contain, clean up, and mitigate any effects that an oil spill may have on waterways. Facilities that could substantially harm waters of the United States are also required to prepare a facility response plan to prevent and respond to discharges of oil or other materials.

Other CWA regulations specifically address discharges of point source effluents from offshore and onshore oil and gas extraction activities (40 CFR 435). There are no offshore facilities in the Project Area. The regulations prohibit any "discharge of waste pollutants into navigable waters from any source, other than produced water, associated with production, field exploration, drilling, well completion, or well treatment (i.e., drilling muds, drill cuttings, and produced sands)" unless authorized by other regulatory provisions. Section 435.50 allows for the discharge of produced water from oil and gas extraction in onshore locations west of the 98th meridian (which extends through central Texas, Oklahoma, Nebraska, Kansas, and North and South Dakota east of the Rocky Mountains) of sufficient quality for use in agricultural or wildlife propagation. Any such discharge must be limited to produced water and not arise from other sources, such as drilling muds, drill cuttings, and produced sands. The discharge must not exceed a daily maximum oil and grease concentration of 35 mg/L. In 2012, about 32,771 AF of produced water was used for agriculture in the Eastern Subarea, pursuant to this regulation.

Additional regulations adopted under the CWA include the National Oil and Hazardous Substance Pollution Contingency Plan (NCP) (codified at 40 CFR 300). The NCP provides national guidance for responding to oil spills and hazardous substance releases, including response capability coordination among emergency responders and applicable contingency plans.

The Safe Drinking Water Act of 1974 (42 U.S.C. §300f et seq.)

The SDWA was originally passed by Congress in 1974 to protect public health by regulating the nation's public drinking water supply. The law was amended in 1986 and 1996, and requires many actions to protect all waters actually or potentially designed for drinking use, whether from above ground or underground sources, including rivers, lakes, reservoirs, springs, and groundwater wells (EPA n.d. [b]). The SDWA authorizes the EPA to set national health-based standards for drinking water to protect against both naturally occurring and man-made contaminants that may be found in drinking water.

Oil and gas extraction typically produces large amounts of brine, which can contain toxic metals and radioactive substances. These brines can cause damage to the environment, and public health, if discharged into water or land. Deep underground injection of brines in formations isolated from underground sources of drinking water prevents soil and contamination. Injection became the preferred way to dispose of waste fluids when states began to implement rules preventing disposal of brine to surface water bodies and soils (EPA n.d. [c]).

The EPA has authority under the SDWA to regulate the subsurface injection of fluids below, into, and above an USDW and has established a UIC program by regulations promulgated under the Act (40 CFR 144-147). A USDW is defined as (1) any aquifer that supplies a public water system; or (2) contains enough groundwater to supply a public water system and either currently supplies drinking water for human consumption or contains less than 10,000 mg/L of TDS. An injection well is used to place fluid underground into porous geologic formations that may range from deep sandstone or limestone, to a shallow soil layer. Injected fluids may include water, wastewater, brine (saltwater), or water mixed with chemicals (EPA n.d. [c]). The EPA ensures that underground injection wells do not endanger any current and future underground or surface sources of drinking water (EPA n.d. [d]). Injection wells are separated into six classes: Class I wells inject hazardous and non-hazardous wastes into deep, isolated rock formations that are separated from the lowest USDW by layers of impermeable clay and rock. Class II wells inject fluids associated with oil and natural gas production operations. Class III wells inject super-heated steam, water, or other fluids into formations to dissolve and extract minerals. Class IV wells inject hazardous or radioactive wastes into underground sources of drinking water and were banned by the EPA in 1984 (EPA n.d. [e]). Class IV wells may only operate as part of an EPA or state authorized groundwater clean-up action. Class V injection wells include wastewater disposal wells used by the geothermal industry and shallow septic system and cesspool wells that drain liquid waste into the ground. Class VI wells are used to inject carbon dioxide into deep rock formations for long-term underground storage, also called geologic sequestration. Geologic sequestration refers to technologies to reduce carbon dioxide emissions to the atmosphere and mitigate climate change (EPA n.d. [f]).

Class II wells are used for oil and gas production throughout the Project Area, including for enhanced oil recovery through the injection of brine, water, steam, polymers, or carbon dioxide into oil-bearing formations to recover oil and natural gas. Class II wells are also used to dispose of fluids associated with oil and gas production by injection into the same underground formation from which they were recovered, a similar formation, or other confined subsurface formations. In certain locations, Class II wells inject liquid hydrocarbons in underground formations (such as salt caverns) for storage. Production wells solely used to bring oil and gas to the surface, and well stimulation treatments, such as hydraulic fracturing, that do not use diesel fuels in fluids or propping agents, are not regulated under the UIC program. However, the EPA does have authority to regulate hydraulic fracturing when diesel fuels are used in fluids or propping agents. Class II wells allow for the disposal of briny produced water in deep underground formations to prevent surface contamination of soil and water and are increasingly used in lieu of surface ponds in the Project Area.

The regulations allow for disposal into aquifers that would otherwise meet the criteria for a USDW if the aquifers are determined to be exempt by the EPA in accordance with an exemption application and review process (40 CFR 146.4). For oil and gas production and Class II well operations, an aquifer may be designated as exempt if it does not currently serve as a source of drinking water and cannot currently or in the future serve as a source of drinking water because it is (1) mineral, hydrocarbon, or geothermal energy producing, or can be demonstrated to contain commercially producible minerals or hydrocarbons; (2) situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical; or (3) so contaminated that it would be economically or technologically impractical to render the water fit for human consumption. Alternatively, an aquifer may be exempted from SDWA protection if the TDS content of the groundwater is more than 3,000 and less than 10,000 mg/L and the aquifer is not reasonably expected to supply a public water system. Aquifers containing TDS greater than 10,000 mg/L are not considered underground sources of drinking water under the SDWA and do not need to be exempted in order for injection to occur.

In 1983, the State of California was granted primacy to regulate Class II wells under the SDWA and must meet federal requirements for the UIC program, including construction, operating, monitoring and testing, reporting, and closure requirements for well owners or operators. All UIC injection activity in the state must be permitted by CalGEM. Class II well operators must meet well construction and conversion standards and perform regular testing and inspection to ensure well integrity. In general, the UIC regulations (40 CFR 146 et seq.) require that owners and operators of new Class II injection wells (1) site wells in locations free of faults and other adverse geological features; (2) drill to a depth that allows the injection into formations that do not contain USDWs, or that contain only exempt aquifers, and that are confined from any other formation that may contain potential drinking water sources; (3) inject fluids through an internal pipe (tubing) that is located inside another pipe (casing), with cement placed between the outside pipe and the well borehole; (4) test well integrity at the time of completion and at least every five years thereafter; and (5) continuously monitor well integrity. CalGEM administers the UIC program for Class II wells in California (see below for more information about the state Class II well regulation program).

National Flood Insurance Program

The National Flood Insurance Program (NFIP) was enacted in 1968 to provide a federal program for participating communities to purchase flood insurance. The program is administered by FEMA, and applicable flood insurance rates are based on the flood hazards identified on FIRMs produced and updated by FEMA. A FIRM identifies the estimated limits of the 100-year flood hazard risk, and to participate in the NFIP, local communities must adopt regulations for floodplain development to reduce flood damage, including flood proofing, elevation on fill, or floodplain avoidance. Kern County participates in the NFIP. The currently applicable flood risks in the Project Area based on the FEMA maps are shown on Figure 4.9-17.

State

Porter-Cologne Water Quality Control Act (CWC §13000 et seq.)

The Porter-Cologne Water Quality Control Act (Porter-Cologne), also known as the CWC, Section 7, provides the state and nine RWQCBs with the authority to regulate discharges of waste into waters of the state. Section 13050(e) defines waters of the state to mean “any surface water or groundwater, including saline waters, within the boundaries of the state.” Porter-Cologne is administered in the Project Area by the CVRWQCB under the Water Quality Control plan for the Tulare Lake Basin Plan (CVRWQCB 2004). The Tulare Lake Basin Plan identifies existing and future beneficial uses for surface water and groundwater within the Planning Area, such as municipal water supply or recreation, and numeric or narrative water quality objectives that will reasonably protect beneficial uses and prevent nuisances. Beneficial uses and water quality objectives in the Tulare Lake Basin Plan also meet applicable federal regulatory criteria for water quality standards and are used to evaluate compliance with state and federal water quality requirements. The Tulare Lake Basin Plan includes standards for groundwaters that are not subject to federal regulation (CVRWQCB 2004). Tables 4.9-7 and 4.9-8 summarize the beneficial uses designated in the Tulare Lake Basin Plan for surface and groundwater in the Project Area.

CWC §13260 requires that any person discharging waste, proposing to discharge waste, or operating or proposing to construct an injection well within any region that could affect the quality of the waters of the state, other than into a community sewer system, must submit a report of waste discharge to the applicable RWQCB. The CVRWQCB reviews reports of waste discharge submitted under Porter-Cologne and issues WDRs that regulate the discharge unless such requirements are waived in accordance with the Water Code or regulations adopted thereunder. For example, discharges of waste into underground injection wells that are regulated under the UIC program are exempt from the requirement to submit a report of waste discharge and are exempt from SWRCB regulations applicable to discharges of waste to land (23 Cal. Code Regs. Section 2511(c)). As discussed above, the CVRWQCB also administers the federal NPDES permit system and, where required, issues water quality certifications for federal permits in the Project Area. If a discharge is also subject to a federal permit, the CVRWQCB will commonly incorporate state WDRs with the issuance of an NPDES permit or a water quality certification.

Stormwater Discharge Regulations

The State Water Resources Control Board has adopted a general NPDES permit for construction activities that disturb one acre or more of land (NPDES General Permit for Storm Water Discharges Associated with Construction and Land Disturbance Activities [2012]), Construction General Permit, Order No. 2009-0009-DWQ, NPDES No. CAS00002 as amended by 2010-0014-DWQ and 2012-0006-DWQ). The general permit applies to discharges of sediment from construction activities associated with oil and gas exploration, production, processing, or treatment operations or transmission facilities. To comply with the general permit, a notice of intent (NOI) must be filed with the State Water Resources Control Board, and a stormwater pollution prevention plan must be implemented at the commencement of grading and remain in effect until construction is completed. Construction-related pollutants must be controlled with the best available technology economically achievable and best conventional pollutant control technology (the best available technology/best control technology standard). The Construction General Permit also requires effluent monitoring and reporting, receiving water monitoring and reporting, a rain event action plan, project site soil characteristics and monitoring, new and redevelopment performance standards for water quality and hydromodification impacts, technology-based numeric action levels, and risk-based permitting.

The 1987 federal Water Quality Act amended the federal CWA to provide that federal and state agencies may not require federal NPDES permits for uncontaminated storm water discharges from oil and gas exploration, production, processing or treatment operations, or transmission facilities. In 2005, the Energy Policy Act added a new provision to the CWA defining the term "oil and gas exploration, production, processing, or treatment operations or transmission facilities" to mean "all field activities or operations associated with exploration, production, processing, or treatment operations, or transmission facilities, including activities necessary to prepare a site for drilling and for the movement and placement of drilling equipment, whether or not such field activities or operations may be considered to be construction activity" (33 U.S.C. §1362(24)).

On June 12, 2006, the EPA published a final rule to address the CWA amendments made by the 2005 Energy Policy Act. The regulation effectively exempted from NPDES permit requirements stormwater discharges of sediment from construction activities associated with oil and gas exploration, production, processing, or treatment operations or transmission facilities unless stormwater from a facility resulted in a discharge of a reportable quantity of oil or hazardous substances. Shortly thereafter, the Natural Resources Defense Council petitioned the Ninth Circuit Court of Appeals (Ninth Circuit) for direct review of the rule, and on May 23, 2008, the Ninth Circuit vacated the 2006 oil and gas construction stormwater regulation (Natural Resources Defense Council v. United States Environmental Protection Agency, 526 F.3d 591 [9th Cir. 2008]). The Ninth Circuit denied the EPA's request for a rehearing of the decision.

The EPA has indicated that, in the aftermath of the Ninth Circuit ruling, oil and gas operators are subject to the stormwater permitting requirements that existed prior to the 2006 rule, subject to the additional legislative provisions added to the CWA by the 2005 Energy Policy Act, and including the following provisions (EPA 2009):

- 40 CFR 122.26(a)(2): The Director may not require a permit for discharges of storm water runoff from mining operations or oil and gas exploration, production, processing or treatment operations or transmission facilities, composed entirely of flows which are from conveyances or systems of conveyances (including but not limited to pipes, conduits, ditches, and channels) used for collecting and conveying precipitation runoff and which are not contaminated by contact with or that has not come into contact with, any overburden, raw material, intermediate products, finished product, byproduct or waste products located on the site of such operations.
- 40 CFR 122.26(e)(8): For any storm water discharge associated with small construction activity identified in paragraph (b)(15)(i) of this section, see 122.21(c)(1). Discharges from these sources, other than discharges associated with small construction activity at oil and gas exploration, production, processing, and treatment operations or transmission facilities, require permit authorization by March 10, 2003, unless designated for coverage before then. Discharges associated with small construction activity at such oil and gas sites require permit authorization by June 12, 2006.
- 40 CFR 122.26(c)(1)(iii): The operator of an existing or new discharge composed entirely of storm water from an oil or gas exploration, production, processing, or treatment operation, or transmission facility is not required to submit a permit application in accordance with paragraph (c)(1)(i) of this section, unless the facility: (A) Has had a discharge of storm water resulting in the discharge of a reportable quantity for which notification is or was required pursuant to 40 CFR 117.21 or 40 CFR 302.6 at any time since November 16, 1987; or (B) Has had a discharge of storm water resulting in the discharge of a reportable quantity for which notification is or was required pursuant to 40 CFR 110.6 at any time since November 16, 1987; or (C) Contributes to a violation of a water quality standard.

The Construction General Permit includes a Rainfall Erosivity Waiver process for sites that are between 1 and 5 acres and that demonstrate that construction activities will have no adverse water quality impacts. Site operators that meet the acreage requirements may seek a Rainfall Erosivity Waiver by submitting a NOI and Sediment Risk analysis to the applicable RWQCB certifying that the construction activity will take place during a period when the value of the rainfall erosivity factor is less than five. Compliance with permit requirements is generally waived in the event that an NOI is approved by the RWQCB.

The SWRCB has also adopted an Industrial General Permit for stormwater. The current permit (Industrial General Permit 97-03-DWQ) expires on June 30, 2015, and a new permit (Industrial General Permit 2014-0057-DWQ) became effective July 1, 2015. The Industrial General Permit includes new online reporting, monitoring, minimum BMPs, numerical action levels and response actions, and other new requirements. Attachment A to the new permit states that “Oil and Gas/Mining Facilities,” including “oil and gas exploration, production, processing, or treatment operations, or transmission facilities that discharge storm water contaminated by contact with or that has come into contact with any overburden, raw material, intermediate products, finished products, by-products, or waste products located on the site of such operations" are subject to coverage. Potentially covered facilities can file a NONA supported by a technical report prepared by a qualified engineer demonstrating that permit coverage is not required because (a) the facility is designed to contain and avoid any discharge of storm water to waters of the United States; or (b) the facility is located in a basin or other location that is not hydrologically connected to waters of the United States. Facilities subject to coverage may also file a No Exposure Certification and seek to obtain conditional exclusion from certain permit requirements for facilities that have no exposure of industrial activities and materials to storm water (40 CFR 122.26(g)).

On November 6, 2018, the State Water Board amended the Industrial General Permit Order 2014-0057-DWQ as amended by Order 2015-0122-DWQ to incorporate the following requirements: (1) Federal Sufficiently Sensitive Test Method Ruling; (2) TMDL Requirements; and (3) Statewide Compliance Options incentivizing onsite or regional storm water capture and use (SWRCB 2015b).

Drilling Mud and Drilling Fluid Discharges to Land

Prior to 2013, discharges of drilling muds and fluids from oil and gas-related well drilling and reworking activity were subject to Central Valley Water Board Resolution No. R5-2003-0008 (General Waiver), which covered a number of low-threat wastes, including drilling mud and fluid discharges. In 2013, the CVRWQCB declined to extend the waiver for oil and gas-related drilling mud and fluid discharges (CVRWQCB 2013b). In response, oil and gas well construction in the Project Area must either utilize closed-loop systems that avoid any discharge of drilling muds and fluids into sumps, or obtain regulatory coverage under SWRCB General Order 2003-0003-DWQ, which addresses low-threat discharges to land, including:

- Wells/boring waste, well development discharge, monitoring well purge water discharge, boring waste discharge;
- Clear water discharges, water main/water storage tank/water hydrant flushing, pipelines/tank hydrostatic testing discharge, commercial and public swimming pools;
- Small/temporary dewatering projects (such as excavations during construction); and
- Miscellaneous, small inert solid waste disposal operations, and cooling discharge.

The general order allows the discharge of boring waste, drilling mud, and cuttings from well-drilling operations to onsite drilling sumps, but prohibits, among other activities, the discharge of: (1) any waste to surface waters; (2) waste classified as "hazardous" or "designated" as defined in Title 22 CCR Section 66261 and the CWC Section 13173; and (3) waste that causes, by itself or in combination with any other discharge, an exceedance of applicable Regional Board Basin Plan objectives for ground or surface waters. The general order also provides that the boring waste, drilling mud, and cuttings may not contain halogenated solvents. At the end of drilling operations, the discharger is required to: (a) remove all wastes from the sump; or (b) remove all free liquid from the sump and cover residual solid and semi-solid wastes, provided that representative sampling of the sump contents after liquid removal shows residual solid wastes to be nonhazardous. Residual wastes must be disposed at a proper Title 27 CCR classified waste disposal facility or onsite. Residual wastes discharged onsite must meet the following requirements: (1) the discharge must be located greater than 5 feet above local groundwater level; (2) the discharge must be covered by a minimum of 1 foot of clean soil; and (3) the discharge must be located at least 100 feet from the nearest surface water. If a drilling sump has appropriate containment features, it may be reused.

On November 15, 2013, the CVRWQCB issued 78 orders pursuant to CWC §13267, that required operators to provide information about discharges of drilling muds into sumps from January 1, 2012, to November 2013. The orders were sent to those operators that had produced more than 1,000 barrels of oil or 10 million cubic feet of natural gas per month or to those operators that drilled exploratory wells. These operators were required to describe the procedures used to close drilling mud pits and smaller temporary operational sumps. If waste was solidified during closure of a sump, then a company was required to describe that solidification process in their response. Staff has informed operators that the CVRWQCB may prepare a general order for the discharge of drilling mud and cuttings to drilling mud pits. If prepared and adopted, the CVRWQCB General Order would replace coverage under the State Water Resources Control Board General Order. As of June 2020, drilling mud and cuttings continued to be regulated under State Water Resources Control Board Water Quality Order No. 2003 – 0003 – DWQ which established statewide general waste discharge requirements for discharges to land with a low threat to water quality (SWRCB 2020).

Produced Water Percolation and Evaporation Ponds

Produced water has been historically disposed of in unlined ponds (surface impoundments), in reliance on an exemption contained in the SWRCB regulations applicable to "discharges of [nonhazardous] wastewater to land, including but not limited to evaporation ponds, percolation ponds, or subsurface leachfields" where the discharge was in compliance with an adopted water quality control plan, including the Tulare Lake Basin Plan (23 CCR §2511(b)). According to CVRWQCB staff, there are an estimated 1,069 active and inactive produced water ponds in the Central Valley region, many of which are located in the Project Area. Approximately 643 of these ponds are regulated under WDRs.

The CVRWQCB is evaluating current and past discharges of produced water into surface ponds to determine whether they are permitted and operating in compliance with state regulations. In the future, unpermitted facilities will be required to obtain WDRs and to comply with other applicable requirements designed to protect groundwater quality. According to the Project Applicant, the CVRWQCB may adopt new general orders that could cover low threat facilities, moderate threat facilities, and no threat facilities. Other facilities may be required to obtain individual WDRs based on site-specific circumstances. The CVRWQCB has indicated that it will issue enforcement orders to oil and gas disposal pond facilities as necessary to bring them into compliance with applicable laws and regulations. <u>*An example of this process is CVRWQB Order No. R5-2017-0112 addressing the timeline for consideration and implementation of alternative disposal methods, including disposal wells and beneficial reuse, at the Race Track Hill Facility in the Edison Oil Field.*</u> If beneficial uses of groundwater have been impaired as a result of historical usage of an unlined pond, investigation and remediation may be required. The CVRWQCB prepared a work plan for the review of Project Area and other central valley disposal ponds, had preliminary workshops and the plan is still under review.

In April 2015, the CVRWQCB issued orders under CWC §13267 to a large number of operators. This section of the CWC authorizes the CVRWQCB to require any person who has discharged waste to submit technical or monitoring program reports to assist the staff in its assessment of potential water quality impacts resulting from the discharge. The orders vary among sites but generally require the collection and analysis of wastewater samples from each of the listed ponds within the operator's control to characterize the discharge. The CVRWQCB also issued inspection reports and notices of violation to some operators in April 2015, which require the operators to file reports of waste discharge, submit closure plans where applicable, or take corrective actions.

Depending on the characteristics of the formation from which the water is produced, produced water could be classified either as "nonhazardous solid waste" or "designated waste" under the SWRCB's waste classifications applicable to discharges of waste to land. "Nonhazardous solid waste" includes "all putrescible and nonputrescible solid, semi-solid, and liquid wastes, including. . . industrial wastes" so long as they are not required to be managed as hazardous wastes and do not contain soluble pollutants in concentrations which exceed applicable water quality objectives, or could cause degradation of waters of the state" (27 CCR §20220(a)). "Designated waste" is defined as "nonhazardous waste that consists of, or contains, pollutants that, under ambient environmental conditions at a waste management unit, could be released in concentrations exceeding applicable water quality objectives or that could reasonably be expected to affect beneficial uses of the waters of the state as contained in the appropriate state water quality control plan" (27 CCR §20210; Water Code §13173).

Produced water that contains concentrations of constituents that exceed water quality objectives will likely be classified as designated waste and will be required to be managed in Class II surface impoundments. Class II surface impoundments must generally be constructed in locations where site characteristics and containment structures isolate wastes from waters of the state. CVRWQCB general orders or WDRs concerning such wastes will require compliance with the design, operating, monitoring, and reporting requirements included in Title 27 CCR §20200 et seq. for Class II surface impoundments. Exceptions to the containment standards may be made where groundwater with actual or reasonably foreseeable beneficial uses is not present or is present in insufficient quantities to serve as a source of water. Where waters with beneficial uses are present and could be adversely impacted, unlined impoundments may have to be retrofitted with liner systems consisting of low permeability natural geological materials (clay) or constructed base materials, such as high-density polyethylene.

Discharges to Injection Wells

Approximately 55,000 injection wells exist in the State of California and are predominantly used for enhanced oil recovery. 80% of UIC wells are in Kern County, and the remainder are in the Central Cost and Los Angeles areas (SWRCB 2017). Injection wells are subject to regulation under both the groundwater protection provisions of the Porter-Cologne Act and by CalGEM through the implementation of the federal UIC program in accordance with a 1983 primacy agreement with the EPA. In March 1988, the State Board and CalGEM (then DOGGR) entered into a MOA that outlines procedures for reporting proposed oil, gas, and geothermal field discharges and for prescribing permit requirements. The procedures are intended to provide a coordinated approach resulting in a single permit satisfying the statutory obligations of both agencies. The purpose of the MOA is to ensure that the construction or operation of Class II injection disposal wells and the land disposal of wastewaters from oil, gas, and geothermal production facilities does not cause degradation of waters of the state. The MOA provides that CalGEM has primary permit authority, subject to review and comment by the state and applicable regional boards, for injection activities regulated by the UIC program. Consistent with the MOA, SWRCB regulations exempt injection wells that are permitted by CalGEM from requirement to file a report of waste discharge or to obtain WDRs that are applicable to other discharges under state law Title 27 CCR §20090(c). The state and regional boards have primary permit authority, subject to review and comment by CalGEM, for all other oil and gas exploration and production regulated discharges. The MOA provides that the agencies will work together to review, prepare and coordinate permits and enforcement. The MOA is included as Appendix 15 of the Tulare Lake Basin Plan.

In 1983, CalGEM (then DOGGR) and the EPA entered into a primacy agreement which implements the federal UIC program in California for Class II wells. CalGEM regulates underground injection wells under 14 CCR §1724 et seq. and other regulations adopted in compliance with the state Public Resources Code and the grant of primacy from the EPA for the UIC program. All underground injection activities, whether for EOR or waste disposal, are subject to regulation under the UIC program. With the exception of hydraulic fracturing that uses diesel fuels, well stimulation activities are specifically excluded from the UIC program under federal law and are regulated under state law (see below). 14 CCR §1724.6 requires that CalGEM approve "any subsurface injection or disposal project," including all UIC Class II wells. 14 CCR §§1724.7 and 1724.8 lists the data an injection well operator must submit to CalGEM to obtain approval for cyclic steam projects. 14 CCR §1724.10 lists the filing, notification, operating, and testing requirements for underground injection projects.

In general, an injection well application must include a detailed engineering study that includes a statement of the primary purpose of the project; the reservoir and fluid characteristics of each injection zone; and the planned well drilling and plugging and abandonment program to complete the project, including a flood-pattern map showing all injection, production, and plugged and abandoned wells, and unit boundaries. The engineering study must also include casing diagrams for all idle, plugged and abandoned, and deeper-zone producing wells within the area affected by the project. The casing diagrams in the engineering study must provide evidence that plugged and abandoned wells in the area will not have an adverse effect on the project or cause damage to life, health, property, or natural resources (14 CCR § 1724.7(a)).

The area affected by a project is defined by the Area of Review (AOR) requirements in the federal UIC regulations, which include a minimum fixed radius of 0.25 mile from a well bore, unless an approved mathematical model, such as a modified "This equation" is used (40 CFR 146.6(a)). When the AOR is determined by using a 0.25-mile fixed radius, the analysis must consider the chemistry of the injected and formation fluids, hydrogeology, population, groundwater use, and dependence and historical injection practices (40 CFR 146.6(b)). CalGEM nominally defines an AOR boundary for a proposed injection well as a .25-mile perimeter around the portion of the well's path that lies within the approved zone of injection as projected on a horizontal plane at ground level. This boundary may be reduced or expanded based on pertinent information regarding a well's completion, the local geology, and other injection parameters, including approved mathematical modeling.

A geologic study and injection plan must also be submitted in support of an injection well application. The geologic study must include a structural and isopach map, a cross section, and a representative electric log that identifies all geologic units, formations, freshwater aquifers, and oil or gas zones (14 CCR §1724.7(b)). The injection plan must include a map showing all injection facilities, maximum anticipated injection pressure and volumes, monitoring system or method used to ensure that injection fluid is confined to the intended zone or zones of injection, method of injection, corrosion protective measures, the source, analysis, and treatment of the injection fluid, and the location and depth of water-source wells to be used in conjunction with the project (14 CCR §1724.7(c)). CalGEM may require additional information for projects that may be hazardous, large, unusual, or particularly complex (14 CCR §1724.7(e)). CalGEM must also approve any desired change or modification of originally-approved injection project operating methods or conditions, such as an increase in size, changed injection intervals, or injection pressure increases (14 CCR §1724.10 (a)).

The injection plan must ensure that injection fluids will be confined to the intended zone or zones of injection (14 CCR §1724.7(c)(3)). To confirm that injection fluid is confined to the approved zone or zones, and will not leak to other formations or zones during injection, mechanical integrity testing must be performed on each injection well when the project begins and periodically thereafter (14 CCR §1724.10(j)). The analysis must consider whether abandoned wells within the AOR could act as a conduit for injection fluid by determining whether adjacent wells include at least 100 linear feet of cement above the approved zone of injection, or a calculated 150 linear feet of cement above the approved zone of injection. When abandoning a well, injection well operators are also required to use every effort and endeavor to protect underground or surface water suitable for irrigation or domestic purposes from the infiltration of detrimental substances (Public Resources Code §3228).

All new wells must fill the annular space to at least 500 feet above oil and gas zones and anomalous pressure intervals (14 CCR §1722.4). All perforations in plugged and abandoned wells must be cemented across and plugged at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shutoff holes, or the oil and gas zone, whichever is highest (14 CCR §1723.1(b)). A minimum 200-foot plug is required across all fresh-saltwater interfaces. An interface plug may be placed wholly within a thick shale if the shale separates the freshwater from the brackish or saltwater sands. If there is cement behind the casing across the fresh-saltwater interface, then a 100-foot plug is required inside the casing across the interface. Squeeze-cementing, a cavity shot, or other special plugging procedures may be required in certain circumstances (14 CCR §1723.2).

Injection well operators are required to maintain data establishing the performance and safety of an injection project and make that data available for periodic review by CalGEM (14 CCR §1724.10(h)). It is CalGEM's policy to review the data for each project on an annual basis to: (1) determine if the injection project is consistent with the permit conditions stated purpose; (2) ensure that all required testing has been performed; (3) determine if there have been any changes to the project, including any drilled, reworked, or abandoned, wells in the AOR, and that any such work was properly completed; (4) confirm that injection fluid is confined to the permitted zone of injection; and (5) confirm that no damage is occurring from the injection project.

The maximum allowable sustained surface injection pressure (MASP) for an injection project must be below the fracture pressure. Prior to sustained injection, a step-rate test must be conducted to determine the MASP (14 CCR §1724.10(i)). CalGEM must be notified in advance of the step-rate test so that it may be witnessed by CalGEM staff. Test pressure must be from hydrostatic to the pressure required to fracture the injection zone or the proposed injection pressure, whichever occurs first. Operators must monitor all injection wells to confirm that injection is at or below the approved MASP. If the injection pressure is above the approved MASP, the operator must immediately reduce the injection pressure. In March 2015, the Supervisor of the CalGEM published a letter in response to inquiries from and a hearing held by the state Senate Committee on Natural Resources and Water confirming that certain steam injections in brittle diatomite formations were known to fracture the diatomite. The letter indicated that CalGEM regulations concerning steam injection were outdated and would be subject to further review and revision in conjunction with other revisions to the UIC program in response to aquifer exemption concerns raised by the EPA (Bohlen 2015).

A Standard Annular Pressure Test (must be performed for each injection well prior to commencement of injection and at least once every five years thereafter (14 CCR §1724.10(j)(1)). In addition, all injection piping, valves, and facilities must meet or exceed design standards for the maximum anticipated injection pressure and must be maintained in a safe and leak-free condition (14 CCR §1724.10(f)). Where there is only a single string of casing across water protected by the SDWA (10,000 mg/L TDS or less), the Standard Annular Pressure Test must be tested at the approved MASP for the well. All tests shall be evaluated to ensure that there are no leaks in the casing and that the fluid is confined to the permitted zone.

The regulations for well construction include standards for the use of casing, mud, and cement and prevent fluid migration and the comingling of lesser quality fluids. In addition to cement above the oil and gas zones, injection wells must be cemented across and at least 100 feet above a base freshwater interface (14 CCR §1723.2). The hole and casing annulus space between the top of the cement isolating the oil and gas zones and the base of the cement covering the base freshwater interface should include heavy mud to prevent the movement of fluids (14 CCR §§1722.6 and 1723(b)). For water disposal wells with proposed injection into a non-hydrocarbon zone, well construction should be consistent with disposal well completed into depleted oil and gas zones. In order to ensure that injected fluids are confined to the intended zone, there must be 100 feet of cement across and above the top of the intended injection zone.

In 2011, the EPA published an independent audit of the California UIC program that identified a number of potential compliance issues, including the possibility that injection wells had been permitted to discharge into 11 oil field aquifers or other locations that met the USDW criteria but that had not been exempted in accordance with applicable requirements (Horsely-Witten Group 2011). The May 2015 letter from CalGEM (then DOGGR) and the SWRCB to the EPA refers to these aquifers as "aquifers that had historically been treated as exempt" (DOGGR 2015c). The SWRCB and CalGEM initiated a work plan to address the UIC program issues identified by the EPA review and subsequent analysis of oil field operations. In February 2015, CalGEM and the SWRCB provided the EPA with a schedule for completing the regulatory review of the state UIC program and in March 2015, the EPA responded to the agencies and identified deadlines and deliverables for the review process. The letters grouped potentially affected wells into three categories. Category 1 includes all disposal wells injecting into non-exempt, non-hydrocarbon bearing aquifers and into the 11 aquifers (eight of which are within the Project Area) that have historically been treated as exempt. Category 2 wells include all EOR wells injecting into non-exempt, hydrocarbon-bearing aquifers. Category 3 wells include disposal and EOR wells located inside the surface boundaries of exempted aquifers, but that may be injecting into a zone that was not subject to exemption.

In May 2015, the SWRCB and CalGEM (then DOGGR) published a letter to the EPA that provided updated information concerning the priority (Category 1) well review process. The letter indicated that 80 of the 532 Category 1 wells identified in February 2015 had been removed from the Category 1 list for various reasons, including injection into an aquifer that did not meet the criteria for a USDW, wells that had not been completed, or wells that were injecting into exempted aquifers. About 21 of the 176 wells identified in February 2015 as injecting into aquifers with less than 3,000 mg/L of TDS were removed from the Category 1 list. The May 2015 letter also indicated that SWRCB staff had determined that 53 of the remaining 155 wells injecting into aquifers with less than 3,000 mg/L of TDS were "potentially impacting drinking water supply wells." As discussed above, 23 of these wells had been ordered to cease operations due to proximity to drinking or agricultural water supplies. The May 2015 letter states that CalGEM and the SWRCB are "awaiting receipt of additional test data" before determining whether to order a shut-down of any of the other 30 wells by the October 15, 2015 compliance date (DOGGR 2015c).

On March 23, 2020, CalGEM and the SWRCB provided the EPA with a letter updating the status of the aquifer exemption program. The update states that CalGEM continues to work in coordination with the State Board to develop, where appropriate, aquifer exemption proposals as a process to address the issue of class II injection wells identified as currently permitted for injection into a potential USDW. The update includes a list of 30 aquifer exemption proposals, 20 of are shown to have been approved by the EPA since 2017, and 10 of which continue to be processed. The update also identified eight other aquifer exemption proposals where current injection into a potential USDW has not been identified, one of which has been approved by the EPA and seven of which continue to be processed. The letter states that progress in addressing the aquifer exemptions "continues to demonstrate the State's commitment to protecting public health and the environment while avoiding unnecessary disruption of oil and gas production" (CalGEM 2019a).

In 2015, several parties filed a lawsuit against CalGEM, contending that the aquifer exemption process implemented by the state and approved by the EPA was unlawful. The lawsuit contended that the state had a mandatory duty under the SDWA to order the immediate closure of oil and gas wells injecting fluids into unexempted aquifers. The lawsuit was denied in September 2016 by the Alameda County Superior Court. In August 2018, Superior Court's decision was upheld by the California Court of Appeal, which also denied request to review the appellate decision on October 24, 2018 (*Ctr. for Biological Diversity v. Cal. Dep't of Conservation*2018; 26 Cal. App. 5th 161) (Justia n.d.).

In 2018, CalGEM and the SWRCB adopted revisions to the 1988 MOA regarding administration of the UIC program for Class II wells, discharges to land and other related issues (SWRCB 2018). The revisions serve to reflect developments in the administration of the state's UIC program for Class II wells, regulating discharges to land of produced water from oil and gas operations, responding to incidents such as spills, taking enforcement actions, and handling other related issues. The procedures are intended to provide a coordinated approach resulting in a single permit satisfying the statutory obligations of both agencies in regulating the injection of fluids to Class II wells and a single permit in regulating the discharge of produced water from oil and gas operations to land.

On April 1, 2019, new UIC regulations took effect that impact about 55,000 wells in California. The regulations affect wells that inject water or steam for enhanced oil recovery as well as wells that return briny groundwater back into the underground source from which it came from (CalGEM 2019b). Key elements of the new regulations include: stronger testing requirements designed to identify potential leaks; increased data requirements to ensure proposed projects are fully evaluated; continuous well pressure monitoring; requirements to automatically cease injection when there is a risk to safety or the environment, and; requirements to disclose chemical additives for injection wells close to water supply wells. Section 1721(n) of the new UIC regulations defines a "surface expression," to mean "a flow, movement, or release from the subsurface to the surface of fluid or other material such as oil, water, steam, gas, formation solids, formation debris, material, or any combination thereof, that is outside of a wellbore and that appears to be caused by injection operations." Section 1724.11(a) of the new UIC regulations states that "underground injection projects shall not result in any surface expression." Since April 2019, several suspected or confirmed surface expressions have occurred, primarily in the Cymric, Midway Sunset, and McKittrick oil fields in the Project Area. In June 2020, the online CalGEM tracking summary of surface expressions stated that "[t]he releases in the Cymric, Midway Sunset, and McKittrick oil fields in Kern County are not near population centers or sources of drinking water. All of the expressions are contained and are clustered in a few areas" (CalGEM 2019a).

CalGEM directly regulates the exploration and production of oil and gas in Kern County for conformance with California's conservation laws. Pursuant to CCR, Title 14, Division 2, Chapter 4, Section 1722 (k), CalGEM establishes Field Rules which supplement more broadly applicable statutory and regulatory requirements regarding well operations in order to protect California's water resources and health and safety. Each Field Rule is specific to an administrative well field and, in many cases, to Areas and Zones or Pools within a field; the rules identify downhole conditions and well construction information to be considered by the oil and gas operators when drilling and completing oil and gas wells. If a Field Rule exists, then those rules must be followed. The Field Rule replaces the existing regulations based upon known geologic conditions. Field Rules have been adopted for most zones and fields in Kern County and are available online.

Produced Water Reuse for Agricultural Irrigation

According to the SWRCB, Kern County is an arid area with water supply issues and an economy linked to agriculture and petroleum extraction. Recycled produced water has been used to irrigate crops in the areas east and north of Bakersfield for more than 30 years, and "to date no studies have shown that irrigating food crops with produced water poses any threat to public health." (California Water Boards 2016).

In response to concerns about the use of produced water for agricultural irrigation, in 2015 the CVRWQCB initiated a Food Safety Project that includes a panel of outside experts and representatives of state agencies responsible for food safety. Members of the panel have expertise in toxicology, risk assessment, agriculture, public health, and wildlife. The purpose of the project is to investigate whether the practice of reusing produced water for irrigation of crops for human consumption poses a threat to human health. Since the project was initiated, several studies, including an assessment of additives used in the oil fields that supply produced water reused for irrigation, a literature review, and crop sampling have been conducted. The CVRWQCB issues WDRs under state law for any use of produced water for agricultural irrigation. The CVRWQCB collectively refers to the oil and gas operators that supply produced water and the irrigation entities that utilize these supplies as "Permit Holders." The Food Safety Project is funded under a memorandum of understanding between the Permit Holders and the CVRWQCB. All studies are performed by a neutral third-party consultant selected by the Permit Holders and approved by the CVRWQCB. The project charter identifies the following roles and responsibilities for the expert panel:

1. *Review and provide recommendations on technical issues relevant to assessing food safety of crops irrigated with produced water.*
2. *Provide perspectives and feedback to the CVRWQCB, including scientific justification and rationale.*
3. *Develop resources or text, or provide other assistance to CVRWQCB staff and facilitators as appropriate. Consistently participate in Panel and public meetings.*
4. *Help identify, review, verify, and critique data, assumptions, analysis and methods used by the Water Board and others in support of food safety assessment.*
5. *Evaluate short- and long-term conditions related to food safety issues.*
6. *Seek consensus on proposals and/or recommendations.*

The project has also contracted with a science advisor from the Lawrence Berkeley National Laboratories to extend internal CVRWQCB expertise for food safety related issues, work as a liaison between the panel and the CVRWQCB staff, and advise and oversee future sampling activities and provide scientific review. (CVRWQCB 2019)

In November 2019, the CVRWQCB published a draft report on the Food Safety Project that includes a summary of the regulatory MRP requirements applicable to the use of produced water for agriculture. The report states that the recycling of water is encouraged by State policy as a means to supplement California's limited water supply, if the water is suitable for the intended use. According to the CVRWQCB, the "Water Quality Control Plan for the Tulare Lake Basin, Third Edition, revised May 2018 (Basin Plan) states that 'blending of wastewater with surface or groundwater to promote beneficial reuse of wastewater may be allowed where the Regional Water Board determines such reuse is consistent with other regulatory policies set forth or referenced herein.'" The Basin Plan designates beneficial uses, establishes water quality objectives, contains implementation policies for protecting waters of the basin, and incorporates policies adopted by the SWRCB. (Central Valley Water Board 2019)

The CVRWQCB report states that the reuse of produced water for irrigation is regulated under WDRs issued by the CVRWQCB, which conditionally permit such use and stipulate maximum groundwater and effluent limits for the facility. A list of the WDRs issued for agricultural reuse of produced water as of October 2020 is provided in Section 4.9.2, Environmental Setting, Surface Water Quality and Existing Oil and Gas Operations, above. The WDRs include MRPs that require monitoring of the discharge and groundwater at specific monitoring frequencies. Water samples are collected at various points of discharge, including after treatment and before irrigation, and analyzed for hundreds of constituents associated with oil field activities, including: salts, metals, VOCs, polycyclic aromatic hydrocarbons (PAHs), radionuclides, and additives. Water samples required under the MRP are sent to a third- party laboratory certified under the SWRCB Environmental Laboratory Accreditation Program and are publicly available for review, including on the Oil Field-Food Safety website maintained by the CVRWQCB. (California Water Boards 2020).

The CVRWQCB report states that the separation and treatment process for Permit Holders that reuse produced water for irrigation consists of two phases. The first phase is the primary separation of the production fluid, which removes the majority of the oil from produced water. In Kern County, this phase normally consists of wash tanks that are designed to separate fluids based on their specific gravity. Some operators elect to heat the wash tanks for increased oil removal efficiency. Oil from the initial phase is pumped to stock tanks (temporarily stored prior to being transported to refineries) and produced water is pumped for the secondary phase of treatment, which consists of one or more of the following processes:

1. *The removal of residual oil and solids using a mechanically induced dissolved air flotation system developed by a specific company;*
2. *The removal of residual oil and solids by passing produced water through a filtering media; or*
3. *Providing additional retention time that enables residual oil to coagulate and rise to the fluid surface to be skimmed and removed from the oil from the water.*

Residual oil captured using a mechanically induced dissolved air flotation systemor pond is either transferred to an oil stock tank or re-injected into the initial phase of the separation/treatment *system. Used filters with recoverable wastes are transported to a permitted third-party facility for disposal.*

According to the CVRWQCB, the complete separation/treatment system configurations for each Permit Holder reusing produced water for agricultural irrigation is described in the WDRs that regulate each facility. In 2015, the CVRWQCB began to issue revised MRPs to require the submission of Safety Data Sheets for all additives used during petroleum exploration, production, and treatment. Safety Data Sheets identified the general chemical make-up (excluding trade secret information) of additives used by Permit Holders. On October 13, 2017, California law was amended to provide the CVRWQCB with authority to require additional disclosure of information related to all chemicals in produced water and to acquire additive information directly from manufacturers. From December 2017 to September 2018, the CVRWQCB issued more than 50 orders pursuant to this enhanced authority to distributors, manufacturers, and suppliers of additives used in oil and gas operations. The CVRWQCB subsequently developed an Oil Field Chemical List consisting of 347 chemicals based on the responses to the orders.

The Food Safety Project panel has met regularly since 2016. Consistent with the program charter and memorandum of understanding, a third-party consultant, GSI Environmental, was retained to complete three tasks: (1) identify "Chemicals of Interest" from a list of known chemical additives and naturally occurring chemicals in produced water for further evaluation; (2) complete a literature review focusing on these chemicals in the context of produced water reuse for agriculture irrigation and other potential sources of these chemicals in the agricultural water supply; and (3) sampling and chemical analysis of crops irrigated with produced water in the Central Valley. As of October 2020, the most recent progress report was posted on the CVRWQCB's Oil Field-Food Safety website on February 25, 2020 (GSI 2020). The progress report provides a summary of "results and major findings," including the following:

- *Known chemicals that can be monitored have many uses outside of oil and gas, and levels do not appear to be significantly different from other exposure sources.*
- *The ability to use produced water for irrigation is dependent on use of treatment and water quality (e.g., salinity, metal content, other hydrocarbons).*
- *There do not appear to be significant differences between blended irrigation water using produced water and known levels in other sources of surface or ground water, and other sources of these chemicals.*
- *There is no evidence to suggest that radionuclides are a problem for food crops irrigated with produced water.*
- *Food crop sampling data conducted from 2017 to 2019, including tree nut, citrus, and vegetable crops such as carrots and potatoes, indicates that overall there does not appear to be any evidence of a difference between treated and control samples that can be attributed to produced water.*

The CVRWQCB Executive Officer's report for October 2020 states that GSI is updating the report based on the comments from the panel, science advisor, and Board staff. For Task 3, Board staff *circulated an updated version of the Task Report to the panel and science advisor for review and received additional comments regarding the Task 3 Report, which were reviewed and forwarded to GSI to update the report as appropriate. The Task 2 and Task 3 reports will be made available to the public upon approval by the panel and require additional work before they are posted on the Food Safety webpage. The Board staff continues to work on the draft White Paper, which will summarize the work and findings of the Food Safety Project. Draft versions of the White Paper will continue to be reviewed by the panel, science advisor, and GSI and following review will be made available to the public for a comment period. The Board staff anticipates that the White Paper will be finalized by the end of the calendar year. Staff is also working on a resolution to be considered by the Board that will outline the findings of the Food Safety Project and provide guidance for addressing new and expanded projects that include the reuse of produced wastewater for irrigation. When complete, the resolution will be presented to the Board during a public meeting. CVRWQCB 2020a*

As discussed above, several of the GSPs and management area plans contemplate the potential expansion of produced water imported into SGMA-regulated basins to increase available irrigation water supplies, reduce potential groundwater demand, and help achieve SGMA objectives. As stated in the Cawelo GSA management area plan, the amount of treated produced water that may be available for irrigation in the Project area "will fluctuate with oil production and long-term availability cannot be predicted." The management area plan adopted by the Cawelo GSA assumes that "delivery rates for treated produced water decrease by one percent every year from 2041 through 2070 to reflect the aging of the oil fields and reduction in oil and gas production" (Cawelo GSA 2019, 99). However, the availability or suitability of produced water supplies in the district, or in any other SGMA basin in the Project Area, depends on several factors, including the extent of future oil and gas operations in response to future industry regulatory and market conditions. All produced water use for irrigation in the Project Area has been, and must be permitted by the issuance of WDRs and MRPs by the CVRWQCB. As noted by the SWRCB and the CVRWQCB, and as discussed in a peer-reviewed study published in May 2020 by researchers from Duke University and RTI International (Duke University 2020), there is ongoing opposition to and concern about treated produced water reuse based on perceived health and safety concerns. The Food Safety Project and expert panel was created by the CVRWQCB to address these issues, and the CVRWQCB has utilized recently amended portions of the California Water Code to significantly increase information about potential chemicals occurring in produced water. Currently available information, including the February 2020 Food Safety Project progress report and the May 2020 analysis by researchers from Duke University and RTI International have not identified significant health or safety risks from the permitted use of produced water for agricultural irrigation, including a wide range of tree and row crops. Nevertheless, in addition to uncertainty regarding the long-term availability of treated produced water from oil and gas operations in the Project Area, perceived health and safety concerns continue to be raised and may further constrain the use of produced water for agriculture in the future.

California Toxics Rule

In 2000, the EPA promulgated federal water quality standards for the State of California after previously adopted water quality objectives for toxic pollutants were overturned in a court proceeding. These federal water quality standards are known as the California Toxics Rule (CTR) and have since been incorporated into regional basin plans, where applicable. The State Board has adopted a policy implementing the CTR (Resolution 2000-015, as amended by Resolution 2000-30). The CTR specifies water quality criteria for 128 priority pollutants based on toxicity to aquatic species, which are used as a basis for the establishment of effluent limitations in NPDES permits. The CTR is applicable to surfaced waters only.

Senate Bill 4 (Well Stimulation Treatment)

Section 1421(d) of the federal SDWA excludes “the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities” from regulation under the UIC program. Effective January 1, 2014, California adopted several new and amended provisions of the Public Resources Code and Water Code to regulate any oil or gas well stimulation activity designed to enhance oil or gas production or recovery by increasing the permeability of the geologic formation that contains hydrocarbon deposits. Well stimulation activities covered by the new legislation include hydraulic fracturing and acid well stimulation treatments. The legislation, commonly referred to as SB 4, amended Sections 3213, 3215, 3236.5, and 3401 of and added Article 3 to Chapter 1 of Division 3 of the Public Resources Code, and added Section 10783 to the Water Code. SB 4 requires that CalGEM (1) promulgate emergency interim and adopt permanent regulations regulating well stimulation treatments by January, 2015, to take effect no later than July 1, 2015; (2) complete a statewide EIR on well stimulation treatments by July 2015; (3) complete an independent scientific study of well stimulation by January 2015; and (4) consult and reach formal agreements with other regulatory agencies to provide regulatory accountability for, and public transparency to, well stimulation treatments by January 2015. SB 4 also requires that the SWRCB develop model criteria for oil and gas-related groundwater monitoring by July 2015. The regulations, studies, and interagency agreements required by SB 4 are intended to regulate water quality and potential geological hazards that could be associated with well stimulation, such as earthquakes or ground instability resulting from bedrock fracturing or acidization. Geology and soils regulatory requirements associated with SB 4 are described in further detail in Section 4.6, Geology and Soils of the 2015 FEIR (SREIR Volume 3).

Since SB 4 was enacted, CalGEM has developed the online tracking tool WellStar for locating well stimulation notices and information required by the applicable regulations. According to CalGEM, the state’s WST regulations “increase operational transparency; reporting requirements, including disclosure of WST fluid chemicals; and neighbor notification with the opportunity for neighbors to seek baseline water quality testing. They require an extensive engineering review and well integrity evaluation for groundwater protection and seismic monitoring. This includes a stoppage for evaluation should any earthquake greater than magnitude 2.7 near a stimulation operation occur. The State Water Resources Control Board also must review all proposed projects to determine whether groundwater monitoring is required” (CalGEM 2020c). In November 2019, CalGEM requested that the Lawrence Livermore National Laboratory (LLNL) conduct a third-party scientific review of pending well stimulation permit applications to ensure the state's technical standards for public health, safety and environmental protection are met prior to approval of each permit. The LLNL also evaluated the completeness of WST operators' application materials and CalGEM's engineering and geologic analyses. CalGEM states that the review is "taking place as an interim measure while a broader audit is completed of CalGEM's permitting process for well stimulation. That audit is being completed by the Department of Finance Office of Audits and Evaluation (OSAE) and will be completed and shared publicly . . . . LLNL experts are continuing evaluation on a permit-by-permit basis and conducting a rigorous technical review to verify geological claims made by well operators in the application process. Permit by permit review will continue until the Department of Finance Audit is complete" (CalGEM 2019c).

The SB 4 regulations requires that certain physical well inspections, documentation, and public notices and disclosures be completed prior to and after completing a well stimulation process. The proposed regulations define well stimulation to include "a treatment of a well designed to enhance oil and gas production or recovery by increasing the permeability of the formation. Well stimulation is a short-term and non-continual process for the purposes of opening and stimulating channels for the flow of hydrocarbons. Examples of well stimulation treatments include hydraulic fracturing, acid fracturing, and acid matrix stimulation" (14 CCR §1761(a)(1)(A)). This definition "does not include routine well cleanout work; routine well maintenance; routine treatment for the purpose of removal of formation damage due to drilling; bottom hole pressure surveys; routine activities that do not affect the integrity of the well or the formation; the removal of scale or precipitate from the perforations, casing, or tubing; a gravel pack treatment that does not exceed the formation fracture gradient; or a treatment that involves emplacing acid in a well and that uses a volume of fluid that is less than the Acid Volume Threshold for the operation and is below the formation fracture gradient" (14 CCR §1761(a)(1)(B)).

Each well operator must obtain a permit from CalGEM in advance of performing a well stimulation treatment and must submit an application that includes the following information: the identification and location of the well; the time period during which the well stimulation treatment is planned to occur; a water management plan; a list of the anticipated identity and concentration of the chemical constituents of the well stimulation treatment fluids the operator plans to use; modeling of the well stimulation treatment axial dimensional stimulation area and identification of plugged and abandoned wells and geologic faults within the modeled treatment area; indication that the operator is developing a groundwater monitoring plan meeting the criteria of the applicable RWQCB (operations cannot commence unless a plan has been approved); an estimate of treatment- generated waste materials that are not addressed in the water management plan; identification and contact information of the operator; the depth of the base of fresh water; the results of specified evaluation and modeling; and casing designs (14 CCR §§1783, 1783.1, 1784).

Once an application has been deemed complete by CalGEM, a well operator must hire an independent entity or person to provide notification to every tenant and owner of neighboring property within a specified distance from the wellhead and horizontal projection of the applicable well at least 30 days prior to commencing a well stimulation treatment. Notified property owners may request baseline and follow-up water quality testing of their domestic and/or agricultural well(s) at the operator's expense, and prior notice of any such testing must be provided to the applicable RWQCB to allow for the opportunity to observe the water sampling process. Well operators must also pressure-test a well and meet certain integrity requirements prior to commencing a well stimulation treatment. An operator may conduct the stimulation activity identified in an approved application and notice within one year from CalGEM approval (14 CCR §§1783.2-1783.3).

The regulations require that, prior to conducting well stimulation, an operator must perform a pressure test after all facilities that could be affected by a proposed well stimulate are in place (14 CCR §1784.1). In addition, a cement evaluation or remediation procedure must be performed to ensure that the cement outside of the well production casing meets applicable regulatory requirements and is sufficient to ensure the geologic and hydrologic isolation of the oil and gas formation during and following the well stimulation treatment (14 CCR §1784.2).

The regulations require the operator to monitor the surface injection pressure, slurry rate, proppant concentration, fluid rate, and pressure of each annuli of the well during a well stimulation treatment. The operator must terminate the well stimulation treatment, report the incident to the Division, and conduct diagnostics in event certain performance and pressure thresholds are exceeded. Notices of any termination must be provided to CalGEM and other state agencies, including the RWQCB (14 CCR §1785). Finally, the proposed regulations require operators to perform ongoing monitoring of a well after a stimulation treatment and to immediately inform CalGEM and the RWQCB, conduct diagnostics, and take all appropriate measures to prevent contamination of protected water or loss of hydrocarbon resources. Tracking of seismic activity during and after well stimulation treatment must be performed using the California Integrated Seismic Network and require evaluation if an earthquake larger than magnitude 2.7 occurs within the vicinity of a well stimulation treatment (14 CCR §1785.1). Materials used in well stimulation are subject to storage, handling, and reporting requirements (14 CCR §1786). Well monitoring must be performed after each well stimulation treatment is completed, including pressure data and diagnostic testing, to verify that the well has not been breached (17 CCR §1787).

Each well operator must disclose, within 60 days after a well stimulation treatment is completed, information regarding the source, volume, and composition and disposition of well stimulation fluids, including, but not limited to, hydraulic fracturing fluids, acid well stimulation fluids, and flowback fluids (14 CCR §1788). The disclosures are provided to CalGEM and must be available online in a format that allows for searching and aggregating the information. A well stimulation treatment report must also be filed with CalGEM, including any information concerning stimulation treatments that differ from what was anticipated in the well stimulation treatment design submitted to CalGEM under Section 1784(b) and whether the actual location of the well stimulation treatment differs from what was indicated in the stimulation permit application. Additional information concerning well stimulation notices and permitting in the state is available at the CalGEM Well Stimulation Treatment website (CalGEM 2020c).

Senate Bill 1281, Disclosure of Oil and Gas Water Use and Disposal

Senate Bill 1281 (SB-1281), effective January 2015, amended Sections 3226.3 and 3227 of the Public Resources Code to require that (1) CalGEM provide the SWRCB with an annual "inventory of all unlined oil and gas field sumps" and (2) well operators provide CalGEM with quarterly information regarding the source and disposition of water produced by or used in oil and gas production in addition to existing obligations to report gas and oil production and produced water information on a monthly basis. The new quarterly reporting requirements include information regarding (1) the source and volume of any water, including produced water (also subject to monthly reporting) used to generate or make up the composition of any injected fluid or gas, identified by water source if more than one water source is used; (2) the volume of untreated water suitable for domestic or irrigation purposes used in oil and gas operations; (3) the treatment of water and the use of treated or recycled water in oil and gas field activities, including, but not limited to, exploration, development, and production; and (4) the specific disposition of all water used in or generated by oil and gas field activities, including water produced from each well as reported in an operator's monthly reports, and separated by volume of disposition if more than one disposition method is used. The amendments retain certain previous monthly reporting requirements in Section 3227, including (1) the amount and gravity of oil, gas and water, and the number of days fluid was produced from each well; (2) the number of drilling, producing, injecting, or idle wells owned or operated by a person subject to reporting requirements; (3) the disposition of gas produced from each field; (4) the disposition of produced water in each field; and (5) the amount of fluid or gas injected into each well used for enhanced recovery, underground storage of hydrocarbons, or wastewater disposal. CalGEM has collected and reported the monthly data described in Section 3227 for several years. As discussed in the 2015 FEIR, CalGEM compiles and publishes quarterly summaries of oil and gas water use reports under SB 1281. As of June 2020, a quarterly report covering about 65% of the state for the first quarter of 2015, and nine subsequent reports from the second quarter of 2015 to the second quarter of 2017, had been published by CalGEM. The quarterly water use reports are discussed in more detail in Section 4.17, Utilities and Service Systems.

Sustainable Groundwater Management Act

In 2014, California enacted the Sustainable Groundwater Management Act (Water Code §10720 et seq.). The Sustainable Groundwater Management Act, and related amendments to California law, require that all groundwater basins designated as high or medium priority in the DWR CASGEM program, and that are subject to critical overdraft conditions, must be managed under a new GSP, or a coordinated set of GSPs, by January 31, 2020. High and medium priority basins that are not subject to critical overdraft conditions must be managed under a GSP by January 31, 2022. Where GSPs are required, one or more local GSAs must be formed to cover the basin and prepare and implement applicable GSPs. The act does not apply to basins that are managed under a court-approved adjudication, or to low or very low priority basins.

A GSA has the authority to require registration of groundwater wells, measure and manage extractions, require reports and assess fees, and to request revisions of basin boundaries, including establishing new subbasins. The preparation of a GSP by a GSA is exempt from CEQA. Each

GSP must include a physical description of the covered basin, such as groundwater levels, groundwater quality, subsidence, information on groundwater-surface water interaction, data on historical and projected water demands and supplies, monitoring and management provisions, and a description of how the plan will affect other plans, including city and county general plans.

The Sustainable Groundwater Management Act defines groundwater as "water beneath the surface of the earth within the zone below the water table in which the soil is completely saturated with water, but does not include water that flows in known and definite channels." A groundwater extraction facility is defined as "a device or method for extracting groundwater from within a basin" (Water Code §10721(g-h)). GSPs are reviewed by the DWR and to ensure that over a period of 20 years "sustainable groundwater management" is achieved. As defined by the act, sustainable groundwater management means that groundwater use within basins managed by a GSP will not cause any of the following undesirable results:

- Chronic lowering of groundwater levels (not including overdraft during a drought, if a basin is otherwise managed);
- Significant and unreasonable reductions in groundwater storage;
- Significant and unreasonable seawater intrusion;
- Significant and unreasonable degradation of water quality;
- Significant and unreasonable land subsidence; and
- Surface water depletions that have significant and unreasonable adverse impacts on beneficial uses (Water Code Section 10721(w)).

SGMA Section 10727 provides that a GSP may be (1) a single plan covering the entire basin developed and implemented by one groundwater sustainability agency; (2) a single plan covering the entire basin developed and implemented by multiple groundwater sustainability agencies; or (3) subject to Water Code Section 10727.6, multiple plans implemented by multiple groundwater sustainability agencies and coordinated pursuant to a single coordination agreement that covers the entire basin. Section 10727.6 requires that GSAs "intending to develop and implement multiple groundwater sustainability plans. . .coordinate with other agencies preparing a groundwater sustainability plan within the basin to ensure that the plans utilize the same data and methodologies for the following assumptions in developing the plan: (a) Groundwater elevation data. (b) Groundwater extraction data. (c) Surface water supply. (d) Total water use. (e) Change in groundwater storage. (f) Water budget. (g) Sustainable yield."

SGMA Section 10733.2 requires DWR to draft and adopt emergency regulations for the evaluation and implementation GSPs and GSP alternatives and subbasin planning coordination agreements. The California Water Commission unanimously approved SGMA proposed emergency regulations proposed by the DWR on May 18, 2016. The emergency regulations became effective on August 15, 2016, and will remain in place until amended by DWR in a subsequent rulemaking (SGMA regulations).

Sections 340 to 340.4 of the regulations implement SGMA Section 10722.2, which allows for the modification of existing groundwater basin boundaries identified by the DWR and basin priority designations under the SGMA. Sections 354.12 to 354.20 of the SGMA regulations define the "basin setting" information that must be included in a GSP. Section 354.12 requires that the basin setting information "shall be prepared by or under the direction of a professional geologist or professional engineer." Section 354.14 requires the preparation of a "descriptive hydrogeologic conceptual model of the basin based on technical studies and qualified maps that characterizes the physical components and interaction of the surface water and groundwater systems in the basin." Section 354.16 requires "a description of current and historical groundwater conditions in the basin, including data from January 1, 2015, to current conditions, based on the best available information."

Section 354.18 requires that each GSP "include a water budget for the basin that provides an accounting and assessment of the total annual volume of groundwater and surface water entering and leaving the basin, including historical, current and projected water budget conditions, and the change in the volume of water stored." Section 354.18(c) requires the development of a "current, historical, and projected water budget for the basin," including "current inflows and outflows for the basin using the most recent hydrology, water supply, water demand, and land use information . . . starting with the most recently available information and extending back a minimum of 10 years." The plan must also include a "projected water budget" that estimates "future baseline conditions concerning hydrology, water demand and surface water supply availability or reliability over the planning and implementation horizon." Sections 354.18(c)(A) through (C) require that the planning and implementation horizon extend for 50 years and include the following:

> (a) utilize 50 years of historical precipitation, evapotranspiration, and streamflow information as the baseline condition for estimating future hydrology" and "as the baseline condition used to evaluate future scenarios of hydrologic uncertainty associated with projections of climate change and sea level rise;
>
> (b) utilize the most recent land use, evapotranspiration, and crop coefficient information as the baseline condition for estimating future water demand" and "as the baseline condition used to evaluate future scenarios of water demand uncertainty associated with projected changes in local land use planning, population growth, and climate; and
>
> (c) utilize the most recent water supply information as the baseline condition for estimating future surface water supply" and "as the baseline condition used to evaluate future scenarios of surface water supply availability and reliability as a function of the historical surface water supply . . . and the projected changes in local land use planning, population growth, and climate.

Section 354.18 states that the DWR will provide "the California Central Valley Groundwater-Surface Water Simulation Model (C2VSIM) and the Integrated Water Flow Model (IWFM) for use . . . in developing the water budget" and that GSAs may develop their own water budget methodologies.

Section 354.20 states that a GSA "may define one or more management areas within a basin if the [GSA] has determined that creation of management areas will facilitate implementation of the [GSP]. Management areas may define different minimum thresholds and be operated to different measurable objectives than the basin at large, provided that undesirable results are defined consistently throughout the basin." Section 354.24 requires that each GSA "shall establish in its [GSP] a sustainability goal for the basin that culminates in the absence of undesirable results within 20 years of the applicable statutory deadline." Section 354.44 states that each GSP "shall include a description of the projects and management actions the [GSA] has determined will achieve the sustainability goal for the basin, including projects and management actions to respond to changing conditions in the basin."

Section 357.4 implements SGMA Section 10727(b)(3) and requires that GSAs "intending to develop and implement multiple" GSPs for a basin "shall enter into a coordination agreement to ensure that the Plans are developed and implemented utilizing the same data and methodologies, and that elements of the Plans necessary to achieve the sustainability goal for the basin are based upon consistent interpretations of the basin setting." Section 357.4(b) requires that the coordination agreement demonstrate that the GSAs "have used the same data and methodologies for assumptions described in Water Code Section 10727.6," including "groundwater elevation data . . . a coordinated water budget for the basin, as described in Section 354.18, including groundwater extraction data, surface water supply, total water use, and change in groundwater in storage" and "sustainable yield for the basin, supported by a description of the undesirable results for the basin, and an explanation of how the minimum thresholds and measurable objectives defined by each Plan relate to those undesirable results, based on information described in the basin setting." Section 357.4(c) provides that "the coordination agreement shall be submitted to the Department together with the [GSPs] for the basin and, if approved, shall become part of the [GSP] for each participating [GSA]." Section 357.4(h) requires that the DWR "evaluate a coordination agreement for compliance with the procedural and technical requirements . . . to ensure that the agreement is binding on all parties, and that provisions of the agreement are sufficient to address any disputes between or among parties to the agreement"

Section 356.2 requires that each GSA submit an annual report to the DWR by April 1 of each year following GSP adoption covering the preceding water year. Section 351(am) defines a water year as the period from October 1 through the following September 30. Section 351(an) defines a "water year type" as the DWR's classification of the amount of annual precipitation in a basin. The annual report must include descriptions of "groundwater elevation data," "groundwater extraction for the preceding water year," "surface water supply used or available for use, for groundwater recharge or in-lieu use shall be reported based on quantitative data that describes the annual volume and sources for the preceding water year," "total water use …using the best available measurement methods by water use sector" and "water source type," "change in groundwater in storage," and "a description of progress towards implementing the [GSP]." Section 355.8 requires that the DWR publicly post the report online, provide written notice if additional information is required, and "review information contained in the annual report to determine whether the [GSP] is being implemented in a manner that will likely achieve the sustainability goal for the basin."

Section 355 describes procedures for DWR review and approval of an adopted GSP. Section 355.2(c) provides that each GSP will be subject to a minimum public review and comment period of 60 days. Section 355.2(e) states that the DWR shall evaluate a GSP "within two years of its submittal date and issue a written assessment" including if the GSP is approved, incomplete, or inadequate. As discussed above in Section 4.9-2, Environmental Setting, GSAs have been formed for all high and medium priority and critically overdrafted basins and subbasins in the Project Area. GSPs have been adopted and submitted for DWR review in accordance with the SGMA Regulations for all high priority and critically overdrafted basins in the Project Area. The Kern County Subbasin accounts of the vast majority of the groundwater located in the Project area and is subject to five GSPs managed under a Coordination Agreement and in accordance with a coordinated water budget developed by the GSAs implementing the GSPs. Small portions of other GSPs that regulate basins and subbasins located primarily outside of the Project Area and Kern County extend into the northern and western margins of the Project Area. A review of the GSPs for these basins and subbasins did not identify discussion of oil and gas activities as a significant factor affecting the attainment of SGMA goals in any of these plans. In 2016, a basin boundary modification was approved by the DWR that created a new White Wolf subbasin south of the White Wolf fault from the prior boundaries of the KCS. The new White Wolf subbasin was identified as medium priority and no GSP is required until January 31, 2022. None has as yet been adopted. There are portions of two lower and low priority subbasins extended from outside of Kern County into the Project Area, neither of which require the formation of GSAs or GSPs to meet SGMA requirements. No GSAs have been formed or GSPs adopted for these locations.

In 2017, the California legislature enacted temporary provisions codified in Water Code Sections 13808 et seq. that required the submission of certain water information in conjunction with applications to a city or county for new wells within a critically overdrafted basin. Among other information, Section 13808(a) requires that water well applicants provide information concerning the location, depth, and proposed capacity of the well, estimated pumping rates, anticipated pumping schedules, and estimated annual extraction volumes, geologic siting information, the distance from any potential sources of pollution onsite and on adjacent properties, the distance from ponds, lakes, and streams within 300 feet, existing wells on the property, the size of the area to be served by the well and the planned category of water use, such as irrigation, stock, domestic, municipal, industrial, or other use. Section 13808.2 requires that the city or county "make the information . . . easily accessible and available to both the public and to groundwater sustainability agencies located within the basin where the new well is located, including "posting the information on the city's or county's Internet Web site . . .." These provisions were operative on January 1, 2018 and expired on January 31, 2020. During this period, the Kern County Public Health Services Department issued permits and water supply certificates for approximately 190 water wells and issued 374 approvals to drill water wells for property zoned appropriately and with an established use. The information required by the temporary provisions of the Water Code was provided to the KGA in accordance with Section 13808.2 of the Water Code.

As described further in Chapter 3, Project Description, under applicable provisions of the California Constitution and state law, as interpreted by the California Attorney General, the County's authority to regulate subsurface activities relating to oil and gas exploration and production is preempted by state and federal laws and regulations. As a result, the County neither directly regulates nor can it impose mitigation measures that directly regulate subsurface activities by oil and gas operators, including those that could affect water quality. The County retains jurisdiction to regulate and require mitigation for oil and gas exploration activities that are conducted at the surface, including those that may affect subsurface water quality.

Local

Kern County General Plan [

The Kern County General Plan (KCGP) was released in September 2009. In 2017, the Kern County Planning and Natural Resources group initiated the process of updating the KCGP for 2040. The Project Area is located within the KCGP area and, therefore, would be subject to applicable policies and measures of the KCGP. The Land Use, Conservation, Open Space Element, and the Safety Element of the KCGP include goals, policies, and implementation measures related to hydrology and water quality that apply to the Project, as described below.

Chapter 1. Land Use, Conservation, and Open Space Element

1.3. Physical and Environmental Constraints

Policies

Policy 1. Kern County will ensure that new developments will not be sited on land that is physically or environmentally constrained ((Map Code 2.1 (Seismic Hazard), Map Code 2.2 (Landslide), Map Code 2.3 (Shallow Groundwater), Map Code 2.5 (Flood Hazard), Map Codes from 2.6 – 2.9, Map Code 2.10 (Nearby Waste Facility), and Map Code 2.11 (Burn Dump Hazard)) to support such development unless appropriate studies establish that such development will not result in unmitigated significant impact.

Policy 2. In order to minimize risk to Kern County residents and their property, new development will not be permitted in hazard areas in the absence of implementing ordinances and programs. These ordinances will establish conditions, criteria, and standards for the approval of development in hazard areas.

Policy 3. Zoning and other land use controls will be used to regulate and, in some instances, to prohibit development in hazardous areas.

Policy 6. Regardless of percentage of slope, development on hillsides will be sited in the least obtrusive fashion, thereby, minimizing the extent of topographic alteration required and reducing soil erosion while maintaining soil stability.

Policy 7. Ensure effective slope stability, wastewater drainage, and sewage treatments in areas with steep slopes are adequate for development.

Policy 8. Encourage the preservation of the floodplain's flow conveyance capacity, especially in floodways, to be open space/passive recreation areas throughout the County.

Policy 9. Construction of structures that impede water flow in a primary floodplain will be discouraged.

Policy 10. The County will allow lands which are within flood hazard areas, other than primary floodplains, to be developed in accordance with the General Plan and Floodplain Management Ordinance, if mitigation measures are incorporated so as to ensure that the proposed development will not be hazardous within the requirements of the Safety Element (Chapter 4) of this General Plan.

Policy 11. Protect and maintain watershed integrity within Kern County.

Implementation Measures

Implementation Measure H. Development within areas subject to flooding, as defined by the appropriate agency, will require necessary flood evaluations and studies.

Implementation Measure I. Designated flood channels and water courses, such as creeks, gullies, and riverbeds, will be preserved as resource management areas or in the case of urban areas, as linear parks whenever practical.

Implementation Measure J. Compliance with the Floodplain Management Ordinance prior to grading or improvement of land for development or the construction, expansion, conversion or substantial improvements of a structure is required.

Implementation Measure M. The State Water Resources Control Board and the Local Enforcement Agency (Kern County Public Health Services Department, Environmental Health Division) shall be consulted when discretionary development has been proposed near a known burn dumpsite.

Implementation Measure N. Applicants for new discretionary development should consult with the appropriate Resource Conservation District and the California Regional Water Quality Control Board regarding soil disturbances issues.

1.4. Public Facilities and Services

Goals

Goal 5. Ensure that adequate supplies of quality (appropriate for intended use) water are available to residential, industrial, and agricultural users within Kern County.

Goal 9. Serve the needs of industries and Kern County residents in a manner that does not degrade the water supply and the environment and protect the public health and safety by avoiding surface and subsurface nuisances resulting from the disposal of hazardous wastes, irrespective of the geographic origin of the waste.

1.9. Resource

Goals

Policy 10. To encourage effective groundwater resource management for the long-term economic benefit of the County the following shall be considered:

(a) Promote groundwater recharge activities in various zone districts.

(b) Support for the development of Urban Water Management Plans and promote Department of Water Resources grant funding for all water providers.

(c) Support the development of groundwater management plans.

(d) Support the development of future sources of additional surface water and groundwater, including conjunctive use, recycled water, conservation, additional storage of surface water and groundwater and desalination.

Policy 11. Minimize the alteration of natural drainage areas. Require development plans to include necessary mitigation to stabilize runoff and silt deposition through utilization of grading and flood protection ordinances.

Policy 12. Areas identified by the Natural Resource Conservation Service (formerly Soil Conservation Service) as having high range-site value should be conserved for Extensive Agriculture uses or as Resource Reserve, if located within a County water district.

Implementation Measures

Implementation Measure C. The County Planning Department will seek review and comment from the County Public Works Department, Engineering and Survey Services Division on the implementation of the National Pollution Discharge Elimination System for all discretionary projects.

Policy 2. Design discretionary critical facilities in the potential dam inundation area used for the storage, or use of hazardous materials to prevent onsite hazards from affecting surrounding communities in the event of inundation.

1.10. General Provisions

1.10.6. Surface Water and Groundwater

Policies

Policy 34. Ensure that water quality standards are met for existing users and future development.

Policy 39. Encourage the development of the County's groundwater supply to sustain and ensure water quality and quantity for existing users, planned growth, and maintenance of the natural environment.

Policy 43. Drainage shall conform to the Kern County Development Standards and the Grading Ordinance.

Policy 44. Discretionary projects shall analyze watershed impacts and mitigate for construction-related and urban pollutants, as well as alterations of flow patterns and introduction of impervious surfaces as required by the California Environmental Quality Act (CEQA), to prevent the degradation of the watershed to the extent practical.

Implementation Measures

Implementation Measure U. The Kern County Public Health Services Department, Environmental Health Division will develop guidelines for the protection of groundwater quality which will include comprehensive well construction standards and the promotion of groundwater protection for identified degraded watersheds.

Implementation Measure X. Encourage effective groundwater resource management for the long-term benefit of the County through the following:

i. Promote groundwater recharge activities in various zone districts.

iii. Support the development of Groundwater Management Plans.

iv. Support the development of future sources of additional surface water and groundwater, including conjunctive use, recycled water, conservation, additional storage of surface water, and groundwater and desalination.

Implementation Measure Y. Promote efficient water use by utilizing measures such as:

i. Requiring water-conserving design and equipment in new construction.

ii. Encouraging water-conserving landscaping and irrigation methods.

Chapter 4. Safety Element

4.4. Dam Failure, Flooding, and Inundation

Policies

Policy 1. Design discretionary critical facilities located within the potential inundation area for dam failure in order to mitigate the effects of inundation on the facility; promote orderly shutdown and evacuation (as appropriate); and prevent onsite hazards from affecting building occupants and the surrounding communities in the event of dam failure.

Policy 2. Design discretionary critical facilities in the potential dam inundation area used for the storage, or use of hazardous materials to prevent onsite hazards from affecting surrounding communities in the event of inundation.

Policy 3. Require emergency response plans for the planning area to include specific procedures for the sequential and orderly evacuation of the potential dam inundation area.

Policy 4. Encourage critical and high occupancy facilities as well as facilities for the elderly, handicapped, and other special care occupants, located in the potential inundation area below the dam to develop and maintain plans for the orderly evacuation of their occupants.

Implementation Measures

Implementation Measure A. Facilities used for the manufacture, storage, and use of hazardous materials shall comply with the Uniform Fire Code, with requirements for siting or design to prevent onsite hazards from affecting surrounding communities in the event of inundation.

Implementation Measure B. Discretionary critical facilities within potential inundation areas shall be designed to mitigate or prevent effects of inundation.

4.5. Landslides, Subsidence, Seiche, and Liquefaction

Policies

Policy 3. Reduce potential for exposure of residential, commercial, and industrial development to hazards of landslide, land subsidence, liquefaction, and erosion.

Implementation Measures

Implementation Measure B. Require liquefaction investigations in all areas of high groundwater potential and appropriate foundation design to mitigate potential damage to buildings on sites with liquefaction potential.

Implementation Measure D. Discretionary actions will be required to address and mitigate impacts from inundation, land subsidence, landslides, high groundwater areas, liquefaction and seismic events through the CEQA process.

Metropolitan Bakersfield General Plan

The Metropolitan Bakersfield General Plan (MBGP), a joint effort between the Kern County Planning Department and the City of Bakersfield Planning Division, was last adopted on December 11, 2007. The MBGP includes both city and unincorporated County lands. The MBGP describes the community's physical development as well as its economic, social and environmental goals and is currently undergoing an update. The Project Area includes a total of 152,040 acres of unincorporated County lands that are covered under the MBGP (7.41%). Project-related development on unincorporated lands within the MBGP Planning Area would be subject to the following applicable policies and implementation measures of the MBGP, with respect to hydrology and water quality.

Chapter V. Conservation Element

A. Biological Resources

Policies

Policy 2. Preserve areas of riparian vegetation and wildlife habitat within floodways along rivers and streams, in accordance with the Kern River Plan Element and channel maintenance programs designed to maintain flood flow discharge capacity (I-4).

B. Mineral Resources

Goals

Goal 4. Protect land, water, air quality and visual resources from environmental damage resulting from mineral and energy resource development.

C. Soils and Agriculture

Policies

Policy 7. Land use patterns, grading, and landscaping practices shall be designed to prevent soil erosion while retaining natural watercourses when possible (I-4).

Policy 12. Prohibit premature removal of ground cover in advance of development and require measures to prevent soil erosion during and immediately after construction (I-4).

D. Water Resources

Goals

Goal 1. Conserve and augment the available water resources of the planning area.

Goal 2. Assure that adequate groundwater resources remain available to the planning area.

Goal 3. Assure that adequate surface water supplies remain available to the planning area.

Goal 4. Continue cooperative planning for and implementation of programs and projects which will resolve water resource deficiencies and water quality problems.

Goal 5. Achieve a continuing balance between competing demands for water resource usage.

Goal 6. Maintain effective cooperative planning programs for water resource conservation and utilization in the planning area by involving all responsible water agencies in the planning process.

Policies

Policy 6. Protect planning area groundwater resources from further quality degradation (I-7).

Policy 8. Consider each proposal for water resource usage within the context of total planning area needs and priorities-major incremental water transport, groundwater recharge, flood control, recreational needs, riparian habitat preservation and conservation (I-9).

Policy 9. Encourage and implement water conservation measures and programs (I-11).

Implementation Measures

Implementation Measure 6. Support the provision of adequate wastewater collection systems and treatment reclamation and disposal facilities which will prevent groundwater degradation by onsite wastewater systems.

Implementation Measure 7. Maintain industrial waste discharge regulation and monitoring programs which protect the planning area groundwater from contaminants.

Implementation Measure 10. Support additional water conservation measures and programs of benefit to the planning area.

Chapter VIII. Safety Element

A. Seismic Safety

Goals

Goal 7. Protect land uses from the risk of dam failure inundation including the assurances that: the functional capabilities of essential facilities are available in the event of a flood; hazardous materials* are not released; effective measures for mitigation of dam failure inundation are incorporated into the design of critical facilities; and the rapid and orderly evacuation of populations in the inundation area will occur.

Critical Facilities Policies

Policies

Policy 4. Encourage critical facilities in dam inundation areas to develop and maintain plans for safe shut-down and efficient evacuation from their facilities, as appropriate to the degree of flood hazard for each facility (I-26, I-31).

Liquefaction Policies

Policies

Policy 13. Determine the liquefaction potential at sites in areas of high groundwater prior to development and determine specific mitigation to be incorporated into the foundation design, as necessary to prevent or reduce damage from liquefaction in an earthquake (I-17 through I-19).

Policy 14. Route major lifeline installations around potential liquefaction areas or otherwise protect them against significant damage from liquefaction in an earthquake (I-20).

Dam Failure Inundation Risk Policies

Policies

Policy 18. Design discretionary critical facilities located within the potential inundation area for dam failure in order to: mitigate the effects of inundation on the facility; promote orderly shut-down and evacuation (as appropriate); and, prevent onsite hazards from affecting building occupants and the surrounding communities in the event of dam failure (I-26).

Policy 19. Design discretionary facilities in the potential dam inundation area used for the manufacture, storage or use of hazardous materials to prevent onsite hazards from affecting surrounding communities in the event of inundation (I-27).

Policy 20. Require emergency response plans for the planning area to include specific procedures for the sequential and orderly evacuation of the potential dam inundation area (I-28).

Implementation Measures

Implementation Measure 2. Require detailed site studies for ground shaking characteristics, liquefaction potential, dam failure inundation and flooding potential, and fault rupture potential, as background to the design process for critical facilities under city and county discretionary approval.

Implementation Measure 17. Require liquefaction investigations in all areas of high groundwater potential and appropriate foundation designs to mitigate potential damage to buildings on sites with liquefaction potential.

Implementation Measure 20. Route major lifeline components such as for Highways, utilities and petroleum or chemical pipelines around areas of high groundwater wherever possible. Where they must cross an area of high groundwater, plans and permits shall require design features to accommodate extensive ground rupture without prolonged disruption of an essential service or threat to health and safety.

Implementation Measure 26. Develop procedures for the discretionary review of critical facilities proposed in an area of potential dam inundation. Approvals shall include requirements that emergency shut-down and facility evacuation plans be developed, maintained and exercised for each facility, and the potential effects of inundation on essential facility functions and the safety of occupants and the community in general are addressed.

Implementation Measure 27. Facilities used for the manufacture, storage or use of hazardous materials shall comply with the uniform fire code, with requirements for siting or design to prevent onsite hazards from affecting surrounding communities in the event of inundation.

Implementation Measure 28. Incorporate Specific Plans for the sequential and orderly evacuation of the potential dam inundation area into emergency response plans.

B. Flooding

Goals

Goal 1. Minimize hazards to planning area residents resulting from flooding.

Goal 2. Reduce the risk of flooding to land uses.

Policies

Policy 1. Develop specific standards which apply to development located in flood hazard areas, as defined by Federal Flood Insurance maps and most recent information as adopted by the responsible agency (I-1, I-2).

Implementation Measures

Implementation Measure 2. Develop procedures for the review of proposed facilities which use, manufacture or store hazardous materials proposed in areas of identified flood hazard.

D. Storm Drainage

Goals

Goal 1. Ensure the provision of adequate storm drainage facilities to protect planning area residents from flooding resulting from storm water excess.

Kern County Specific Plans

As of 2020, Kern County has adopted 37 Specific Plans for properties within the Project Area. These Specific Plans are intended to be an amplification of the goals and policies of the KCGP and are, therefore, consistent therewith. As depicted in Figure 4.10-3, less than 8% of the Project Area is located wholly or partially within adopted Specific Plan areas. Future oil and gas exploration and production activities that would be authorized under the proposed Amendment to Chapter 19.98 (Oil & Gas Production) of the Kern County Zoning Ordinance that would be located within the boundary of an adopted Specific Plan would be regulated according to County zoning, with the exception of the Specific Plans identified as Tier 5.

Kern River Plan Element

The Kern River Plan Element, which is included in both the KCGP and the MBGP, includes implementation measures related to hydrology and water quality. The plan was adopted in 1985 and includes implementation policies applicable to County land within the Kern River Plan Element area. These policies are outlined below.

3.2. Open Space Versus Development

Policies

Policy 11. New or relocated utility lines shall be placed underground, except in areas subject to intensive agricultural uses, areas designated as A.4 (Mineral and Petroleum) and electrical power lines to oil wells, water wells, and water control devises in areas designated as 8.5 (Resource Management) unless otherwise required by law, and at River crossings, or where it can be shown that the specific nature of the facility is such that it is entirely infeasible to do so.

3.4. Floodplain Management

Policies

Policy 9. Oil and mineral exploration and production shall be allowed within the secondary floodway, provided that adverse effects on riparian vegetation and wildlife habitat are minimized. Appurtenant facilities, such as tank farms and steam generators, shall be located outside any floodway; except that they may be allowed within the 8.4/2.5 (Mineral and Petroleum/Secondary Floodway) upon showing by the operator that no other location is reasonably available for then, the proposed location and extent of construction is necessary for the operation of wells in the immediate vicinity, and the intent of this plan for the secondary floodway is followed.

Policy 10. Resource extraction activities, such as sand and gravel removal, shall comply with the “California Surface Mining and Reclamation Act of 1975.”

3.5. Private Property and Public Use

Policies

Policy 2. Open space qualities of the Kern River primary and secondary floodway shall be protected consistent with policies of this plan, regardless of whether the land is in public or private ownership.

3.6. Mineral and Petroleum

Goals

Goal. To provide for the continued production of petroleum resources and to ensure that future exploration activities can take place, while ensuring that other open space values in the River area are reasonably protected. Utilize sand and gravel resources of the River in such a way as to ensure that floodway, groundwater recharge, and wildlife habitat values are protected.

Policies

Policy 1. Sand and gravel removal shall be done in such a manner as not to degrade, or otherwise adversely affect, the natural and scenic qualities of the Kern River, riparian vegetation, or wildlife habitat except as is necessary or appropriate to maintain the required channel capacity for flood control in the primary floodway.

Policy 5. Mineral and petroleum exploration and extraction activities are permitted in the primary and secondary floodways subject to regulations, to be adopted within a two-year period by the County and City to accomplish the goals and policies of this Element and to mitigate adverse impacts which may otherwise result from construction of facilities and access thereto. Such regulations shall include, but need not be limited to, requirements limiting the impact of access and facilities construction upon adjacent areas, prohibiting activities creating obstructions to floodflow, establishing minimal standards for flood proofing all wells, pumps and associated equipment, specifying spill prevention control and counter-measure plans and emergency procedures, and specifying site and access restoration.

Chapter IV. Map Provisions and Policies

The intent of this plan with regard to the Primary and Secondary Floodways of the Kern River is that:

- No development or physical improvements for uses in the Primary Floodway that would restrict flows, interfere with groundwater recharge, or increase the rise in water surface during high flows of the Kern River, or displace the primary floodway will be permitted.
- Limited development, with an emphasis on preserving open space within the area of the Secondary Floodway, with recognition of the potential flood hazard that exists therein, may be permitted.

Chapter V. Implementation Policies

B. Open Space and Development

Implementation Policies

Implementation Policy 2. Any new non-open space development, including projects by public agencies, shall not occur without prior city or County approval of a “Development Plan.” The Development Plan shall be reviewed for completeness and consistency with the following guideline:

f. A certified delineation of the primary and secondary floodways, if applicable to the site, depicting both predevelopment conditions and future development conditions.

Implementation Policy 4. All new development and accessory uses, excepting wells, shall maintain a minimum setback of 90 feet from the primary floodway line. If not feasible to do so because of lot size or configuration, new development, including accessory uses, shall maintain a setback from the primary floodway line of 60% or greater of the distance between the primary floodway line and the point of the lot farthest from the primary floodway.

Floodplain Management

Kern County has adopted a Floodplain Management Ordinance (Chapter 17.48 of the Building and Construction Code) that applies to “any man-made change to improved or unimproved real estate, including, but not limited to, buildings or other structures, mining, dredging, filling, grading, paving, excavation, drilling operations, or storage of equipment or materials.” The purposes of the ordinance include the promotion of “public health, safety, and general welfare, and to minimize public and private losses due to flood conditions” and compliance “with the requirements of the NFIP Regulations.” Among other implementation measures, the ordinance (1) restricts or prohibits certain uses that are susceptible to flood damage or increase erosion and flood heights or velocities; (2) requires that uses vulnerable to floods be protected against flood damage at the time of initial construction; (3) controls the alteration of natural floodplains, stream channels, and natural protective barriers that accommodate or channel flood waters; (4) controls filling, grading, dredging, and other development which may increase flood damage; and (5) prevents or regulated the construction of flood barriers which will unnaturally divert flood waters or which may increase flood hazards in other areas.

The KCGP Safety Element indicates that the Primary Floodplain illustrated on relevant FIRMs be mapped with respect to any proposed development. The Primary Floodplain is the area that has a 1% probability of occurrence in any given year (the 100-year floodplain). Chapter 19.50 of the Kern County Zoning Ordinance establishes a Floodplain Primary (FPP) and a combining Floodplain Secondary district with associated restrictions on land use. The FPP District prohibits construction of storage tanks, sumps (ponds), processing equipment, or other similar facilities related to oil and gas production not expressly permitted pursuant to Section 19.50.020 and Subsection C of Section 19.50.130 of Chapter 19.50 of the Kern County Zoning Ordinance. Subsection C provides that oil or gas wells, including pumps and all other associated equipment, and feasible remedial work, improvements and floodproofing of facilities are permitted within the FPP district if they will not obstruct flows, will not cause peripheral flooding of other properties, will not cause any increase in flood levels during the occurrence of the base flood discharge, will be resistant to flotation and immune to extensive damage by flooding, and will not endanger life or property.

4.9.4 Impacts and Mitigation Measures

Methodology and Assumptions

Potential project impacts to hydrological resources are primarily related to the volume and disposition of M&I and produced water and construction and operational activities that could affect surface water or groundwater quality. As discussed in Chapter 3.0, Project Description, potential impacts are primarily evaluated in this SREIR on the basis of the projected increase in production wells within each subarea and tier. <u>*In addition, as discussed in Section 4.92, Environmental Setting, Water Supply Baseline Update, each GSP and management area plan adopted for any portion of the Project Area was reviewed to identify the extent to which oil and gas operations were identified as a significant factor affecting the achievement of SGMA objectives. None of the adopted GSPs and management areas plans within the Project Area identify oil and gas operations as a significant factor affecting the achievement of any of SGMA objectives. Almost all of the GSPs and management area plans explicitly exclude oil and gas operational areas and exempted aquifers from SGMA-regulated groundwater basins. Several of the plans identify the potential use of treated and/or blended oil and gas produced water as a potential source of new imported water that would increase available supplies for agricultural irrigation purposes and reduce potential groundwater demand over time. For more information concerning the discussion of oil and gas activities, including produced water generation and use in each adopted GSP and management area plan in*</u>

the Project Area, see Section 4.9.2, Environmental Setting, Project Area Groundwater Sustainability Plans and Oil and Gas Activities and Appendix D of this SREIR.

The project could result in the permitting of up to 2,697 new production wells each year, 64% of which would be located in the Western Subarea, 5% in the Central Subarea, and 31% in the Eastern Subarea. About 90.1% of all new production wells (2,430 wells) would be located in existing Tier 1 production areas, including 94.2% (1,630 of 1,730 new production wells) in the Western Subarea, 76.3% (100 of 131 new production wells) in the Central Subarea, and 83.7% (700 of 836 new production wells) in the Eastern Subarea. Up to 6.3% of the new production wells in the Project Area (169 wells per year) would be located in Tier 2 areas where agriculture is currently the predominant land use. Using the ground disturbance factors discussed in Appendix F of the 2015 FEIR (SREIR Volume 4), up to 4,856 acres of new disturbance could occur each year in the Project Area, of which 90.6% (4,400 acres) would occur in existing Tier 1 production areas, and 298 acres (6.13%) would occur in Tier 2 areas. About 158 acres of new disturbance could also occur in Tiers 2 through 5. These estimates are conservative because new well construction and operations would likely utilize existing access roads and other oil and gas infrastructure to a greater extent than assumed in the impact projections, especially in more heavily developed Tier 1 areas.

The Applicant estimates that demand for water needed for oil and gas exploration and production activities would increase by about 37% from 2012 to 2035, based on anticipated increases in production activity. The methodology used to estimate future water demand is described in detail in Appendix T-1 of the 2015 FEIR. The analysis indicates that oil and gas M&I water demand would increase from 8,778 AF to 11,761 AF, and produced water demand for oil and gas uses would increase from 88,812 AF to 121,412 AF over this period. The Applicant's water demand estimates assume that 38,658 AF of treated produced water, the amount supplied for agricultural use in 2012, would continue to be supplied over the analysis period. As a result, total produced water demand in the Project Area for oil and gas and agricultural uses is anticipated to increase from 127,470 AF in 2012 (88,812 AF used for oil and gas activities plus 38,658 AF of agricultural reuse) to 160,070 AF in 2035 (121,412 AF used for oil and gas activities plus 38,658 AF of agricultural reuse) (2015 FEIR, Appendix T-1 [SREIR Volume 5).

The extent to which future project-related M&I and produced water demand could affect surface water and groundwater quality, groundwater supply and hydrological resources is subject to several uncertainties, including (1) the total amount of produced water that would be generated from future oil and gas exploration and production; (2) the amount of produced water reused for EOR and other oil and gas-related purposes and for agricultural irrigation; and (3) the amount of produced water that is disposed of in surface evaporation or percolation ponds or Class II injection wells. As shown on Figure 4.9-7, the ratio of produced water to recovered hydrocarbons has increased over time in the Project Area, but fell slightly from 2012 to 2013. As existing oil fields become more depleted, it is generally expected that the volume of produced water per unit of extracted hydrocarbons would increase, but new technologies, or the potential development of new oil shale resources, may affect the future amount of produced water that is generated in the Project Area.

The amount of treated produced water available for agricultural or other non-oil and gas-related reuse, such as landscape irrigation, may also change over time in response the current drought, state policies to encourage water conservation and reuse, and in the event demand from agricultural or urban users increases. The amount of produced water disposed into surface ponds is also likely decrease in the future in response to the RWQCB and other efforts to reduce or eliminate disposal of produced water to surface ponds. As shown on Figure 4.9-15 and Table 4.9-19, the use of Class II injection wells for disposal increased since 2001, in part due to declining surface pond use.

Three projections of project-related water use in 2035 based on the Applicant's demand estimates were developed to analyze a range of potential water demand and supply outcomes. All of the scenarios assume that the amount of produced water generated by oil and gas exploration and production would increase by 37% from 2012 levels by 2035. The three scenarios focus on potential variation in the amount of surface pond disposal, injection well disposal, and reuse of produced water that could occur under future conditions. The 2035 scenarios are summarized in Table 4.9-27. *The scenarios are not intended to be, and do not provide, predictions of produced water use or other potential methods of produced water disposal. Each identifies a possible range of outcomes varying from continuation of existing produced water reuse and disposal patterns (scenario 1), to greater use of underground in place of surface disposal (scenario 2) and a possible expansion of underground disposal and expanded produced water reuse to further reduce surface disposal and associated potential water quality impacts (scenario 3). As discussed in Section 4.9.3, Regulatory Setting,* Produced Water Reuse for Agricultural Irrigation*, several factors could constrain the use of produced water for irrigation. Under these conditions, less produced water would be used for irrigation, and more would be subject to injection well or land disposal. The three scenarios are discussed in more detail in the sections that immediately follow Table 4.9-27.*

Table 4.9-27: Oil and Gas Exploration and Production Produced and M&I Water Supply and Demand 2012 and 2035 (Scenarios 1, 2, and 3)

	2012	**Scenario 1 Pro-Rata Increase**	**Scenario 2 50% Surface Disposal Reduction**	**Scenario 3 Full M&I Water Use Offset and 90% Surface Disposal Reduction**
Water Supplied				
Produced Water	234,959	321,894	321,894	321,894
M&I Water	8,778	11,761	11,761	11,761
TOTAL	**243,737**	**333,655**	**333,655**	**333,655**
Water Use				
Treated Produced Water				
EOR water and steam injections, pressure maintenance and well pulling	88,668	121,215	121,215	121,215
Coil tubing, dust control, surface facility construction	144	197	197	197
Oil and gas produced water reuse	88,812	121,412	121,412	121,412
Agricultural reuse	38,658	38,658	38,658	50,419
Subtotal: Produced Water Reuse	**127,470**	**160,070**	**160,070**	**171,831**

Table 4.9-27: Oil and Gas Exploration and Production Produced and M&I Water Supply and Demand 2012 and 2035 (Scenarios 1, 2, and 3)

	2012	Scenario 1 Pro-Rata Increase	Scenario 2 50% Surface Disposal Reduction	Scenario 3 Full M&I Water Use Offset and 90% Surface Disposal Reduction
M&I Water				
New Well Construction (Drill Mud + Well Stimulation)	589	789	789	789
Maintenance (Mud Services + Cementing)	61	82	82	82
Maintenance (Acidizing + Coil Tubing)	52	70	70	70
Maintenance (Well Pulling + Domestic Water)	594	796	796	796
Well Abandonment	202	271	271	271
Steam Production	7,279	9,754	9,754	9,754
Oil and gas M&I water demand	8,778	11,761	11,761	11,761
Subtotal: Oil and Gas Water Demand, M&I and Produced Water	**97,590**	**133,173**	**133,173**	**133,173**
Injection Well Disposal	84,571	125,905	152,600	152,928
Produced Water Land Disposal	30,223	41,806	15,112	3,022
Subtotal: Oil and Gas Produced Water Waste Disposal	**114,794**	**167,711**	**167,711**	**155,950**
TOTAL	**243,737**	**333,655**	**333,655**	**333,655**

Sources: Table 28 for 2012, and projected values for Scenarios 1–3, Appendix T-1, 2015 FEIR
Note:
All values subject to rounding error and may vary slightly from Table 28.
Key:
EOR = enhanced oil recovery
M&I = municipal and industrial

Scenario 1

Scenario 1 assumes that produced and M&I water demand and use, and produced water disposal by injection and into surface ponds, would increase proportionately from 2012 levels. Agricultural use of treated produced water is assumed to remain at 32,771 AF per year. Under these assumptions, produced water generated in the Project Area would increase from 234,959 AF to 324,243 AF by 2035, and total demand for produced water for oil and gas activities and agricultural irrigation would increase from 121,583 AF to 154,183 AF per year, or about 48% of the available supply of produced water. The remaining 167,711 AF of produced water would be disposed into surface ponds and injection wells in the same proportion as in 2012. Surface disposal would increase from 30,223 AF to 41,806 AF, and injection well disposal would increase from 84,571 AF to 125,905 AF.

Scenario 2

Scenario 2 includes the same water supply and demand results as Scenario 1 except that the amount of produced water disposed into surface ponds is assumed to fall by 50% from 2012 levels in response to the Tulare Lake Basin Plan and other policies that discourage unlined surface pond use. Produced water that was previously disposed into surface ponds would instead be disposed into Class II injection wells. As shown in Table 4.9-27, under these assumptions produced water surface disposal would fall from 30,223 AF to 15,112 AF, and injection well disposal would increase from 127,177 AF to 152,600 AF by 2035.

Scenario 3

Scenario 3 analyzes the potential disposition of produced water assuming about 7% of the 168,983 AF of produced water subject to disposal in Scenarios 1 and 2 is treated and used for other purposes, including oil and gas operations, agricultural irrigation, or other M&I uses. This amount of additional produced water reuse would fully offset the projected oil and gas demand for 11,761 AF of M&I water in 2035. Scenario 3 also assumes that the volume of produced water disposed into surface ponds declines by 90% from 2012 levels as surface disposal is avoided except in relatively rare and unavoidable circumstances. Under these conditions, the amount of produced water that could be reused for agricultural purposes would rise from 32,771 AF to ~~*444,532*~~ *50,419* AF, and total amount of produced water that could be used for oil and gas or agricultural activities would increase to 165,944 AF compared with 121,583 AF in 2012, and 154,183 AF by 2035 in Scenarios 1 and 2. The total amount of produced water subject to disposal would be reduced from 167,711 AF to 155,950 AF in 2035, and pond disposal would fall to 3,022 AF compared with 30,223 AF in 2012, 41,806 AF in Scenario 1, and 15,112 AF in Scenario 2. Produced water disposal by injection would be 152,928 AF, about the same as in in Scenario 2.

As discussed above in Section 4.9.2, *Environmental Setting, Project Area Groundwater Sustainability Plans and Oil and Gas Activities, in Appendix D of this SREIR* ~~*Environmental Setting*~~ and in Section 4.17, Utilities and Service Systems, the increased use of treated produced water to offset oil and gas M&I is included as potential SGMA projects that could be implemented to achieve SGMA requirements by 2041 in the GSPs and management area plans adopted for the KCS. The feasibility of achieving the results in Scenario 3, and the extent to which additional produced water could be reused to offset oil and gas M&I water use in the Project Area, depends on several factors, including produced water quality, treatment costs and requirements, the availability of conveyance capacity to route produced water to and from treatment facilities, and the availability of institutional mechanisms for managing produced water treatment and distribution. Feasibility studies are being or will be conducted by the GSAs with responsibility for implementing proposed SGMA Projects that include produced water use in the Project Area, and none have yet been completed. As discussed above, the CVRWQCB has determined that, in certain instances, even relatively high-quality produced water available from certain oil fields in the Eastern Subarea has, on occasion, not met applicable arsenic or oil and grease water quality standards. Additional management measures, including percolation into water banking facilities, have been required to address these water quality concerns (CVRWQCB 2011, 2012). The reuse of additional produced water, particularly supplies with lower quality than available in the Eastern

Subarea, could require more intensive, technically demanding and more costly forms of treatment. It is possible that treatment requirements could have other environmental effects related to increased energy use and air quality and greenhouse gas emissions, or post-treatment waste stream disposal. *For more information concerning the regulatory framework, ongoing monitoring and assessment, and other efforts by the CVRWQCB to ensure that agricultural irrigation using produced water protects health and safety, see Section 4.9.3,* Regulatory Setting, Produced Water *Reuse for Agricultural Irrigation.*

Oil and gas operators may be able to substitute additional produced water for M&I supplies to conduct certain oil field activities, including EOR and steam production. EOR activities currently account for the largest share of oil and gas M&I water use. Certain EOR operations, such as steam generation, may require higher quality water supplies than can be typically be obtained from treated produced water to avoid equipment corrosion or damage and potential chemical interactions. The use of produced water for other oil field activities, such as discharge for dust suppression, would require additional permitting and approvals to avoid impacts to biological, surface water, groundwater, and other resources. The extent to which oil field operators can feasibly increase produced water reuse and decrease oil and gas M&I demand is uncertain. The Project Applicant has estimated that up to 1,200 well stimulation treatment operations subject to California's SB 4 regulations could occur per year, including 1,050 stimulations in the Western Subarea (88% of the total number of stimulations), 125 in the Central Subarea (10% of the total number of stimulations), and 25 in the Eastern Subarea (2% of the total number of stimulations). About 90.1% of all well stimulation treatments (1,081) would be located in existing Tier 1 production areas, and 6.3% (76) would be located in Tier 2. About 2,231 wells would be plugged and abandoned in accordance with CalGEM regulations each year, including 1,839 wells in the Western Subarea (82% of the total wells), 38 in the Central Subarea (2%), and 354 (16%) in the Eastern Subarea. About 90.1% of all new plugged and abandoned wells (2,010 wells) would be located in existing Tier 1 production areas, and 6.3% (141 wells) would be located in Tier 2.

The following sections evaluate potential project-related construction and operational impacts to hydrological resources, and identify appropriate mitigation where required and feasible, with reference to the thresholds of significance discussed below.

Thresholds of Significance

The CEQA Appendix G Checklist and the Notice of Preparation for this Project state that a project would have a significant impact on hydrology and water quality if it would:

- Violate any water quality standards or waste discharge requirements or otherwise substantially degrade surface or groundwater quality.
- Substantially decrease groundwater supplies or interfere substantially with groundwater recharge such that the project may impede sustainable groundwater management of the basin.

- Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or through the addition of impervious surfaces, in a manner which would:
  - (i) result in a substantial erosion or siltation on –or off-site;
  - (ii) substantially increase the rate of amount of surface runoff in a manner which would result in flooding on-or offsite;
  - (iii) create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff; or
  - (iv) impede or redirect flood flows.
- In flood hazard, tsunami, seiche zones, risk release of pollutants due to project inundation.
- Conflict with or obstruct implementation of a water quality control plan or sustainable groundwater management plan.

Project Impacts

Impact 4.9-1: Violate any water quality standards or waste discharge requirements or otherwise substantially degrade surface or groundwater quality.

The analysis of the potential of the Project to violate any water quality standards or waste discharge requirements was assessed in Chapter 4.9 of the 2015 FEIR (SREIR Volume 3). *The 2015 FEIR disclosed that surface or subsurface discharges related to produced water reuse and disposal, produced water reuse for EOR activities, produced water reuse for agricultural irrigation, produced water conveyance and disposal in ponds and injection wells, and surface or subsurface discharges related to well stimulation activities could result in a violation of water quality standards waste discharge requirements. Wastewater and other operations-related fluids and chemicals can be spilled as a result of equipment leaks, including from pipes and storage tanks, as well as from casing and cement failures and human error, including from accidents involving the surface transport of products used ns produced by the oil and gas industry. Further, incidents such as the leak from the Plains All American Pipeline can impact surface and groundwater, as well as oceans and coastal areas. The 2015 FEIR concluded that, with the implementation of mitigation and compliance with applicable regulatory standards and requirements, potential impacts to water quality would be less than significant.*

Since 2015, various new regulatory requirements have been adopted addressing produced water disposal. As described in Section 4.9.3, Regulatory Setting produced water percolation and evaporation ponds in the County are regulated by the CVRWQCB, which has issued orders to operators under CWC § 13267 requiring submittal of a technical or monitoring program report to assist staff in its assessment of potential water quality impacts resulting from discharge. A list of such orders is available on the CVRWQCB website. CVRWQCB 2019b. The CVRWQCB maintains and regularly updates a Produced Water Ponds List, the most recent version of which is dated November 19, 2019 (CVRWQCBc 2019c). Since 2015, the CVRWQCB has also issued three

General Orders imposing new Waste Discharge Requirements for oil field discharges to land- 2017-0034, 2017-0035, and 2017-0036. CVRWQCB 2020b. The General Orders include requirements related to the potential contamination of soils in produced water ponds. As further described in Section 4.9.3, Regulatory Setting, discharges to injection wells are regulated by CalGEM. On April 1, 2019, new UIC regulations took effect that impact about 55,000 wells in California requiring, among other things, stronger testing requirements designed to identify potential leaks; increased data requirements to ensure proposed projects are fully evaluated; continuous well pressure monitoring; requirements to automatically cease injection when there is a risk to safety or the environment, and requirements to disclose chemical additives for injection wells close to water supply wells. Further, the SB 4 regulations require the operator to develop a groundwater monitoring plan meeting the criteria of the applicable RWQCB (operations cannot commence unless a plan has been approved), and further requires operators to perform ongoing monitoring of a well after a stimulation treatment and to immediately inform CalGEM and the RWQCB, conduct diagnostics, and take all appropriate measures to prevent contamination of protected water or loss of hydrocarbon resources.

From 2017 to 2020, the EPA approved 20 aquifer exemptions, including several within the Project Area and encompassing many of the wells identified in the GSPs (see discussion under Impact 4.9.2). Several other aquifer exemption proposals are being reviewed and considered by CalGEM, including locations in the Project Area (CalGEM 2020d). According to CalGEM, the ongoing implementation of the aquifer exemption work plan "continues to demonstrate the State's commitment to protecting public health and the environment while avoiding unnecessary disruption of oil and gas production." Pursuant to the SB-1281 regulations (discussed in Section 4.9.3, Regulatory Setting), operators are required to report their full water disposition, including produced water downhole disposal (injection wells) and surface disposal (percolation and evaporation ponds) to CalGEM on a quarterly basis via the WellStar system. At least one operator reports that decreasing the volume of produced water discharged to ponds and sumps, together with the completion of the regulatory approval process for additional aquifer exemptions, has led to an increase in the volume of wastewater disposal by underground injection.

In 2017, the CVRWQB issued Order No. R5-2017-0112 addressing the timeline for consideration and implementation of alternative disposal methods, including disposal wells and beneficial reuse, at the Race Track Hill Facility in the Edison Oil Field, an oil wastewater site near Bakersfield, which had reportedly resulted in groundwater contamination from chloride and boron. Since April 2019, several suspected or confirmed surface expressions have occurred, primarily in the Cymric, Midway Sunset, and McKittrick oil fields in the Project Area. With oversight from CalGEM, flows from the Cymric incident are fully captured within engineered containment. The operator has developed a field-wide plan designed to permanently stop the seep. The plan includes stopping steam injection field-wide and injecting water to cool the reservoir; drilling intercept re-abandonment wells to permanently abandon known broken wellbores (in other words, permanently seal them with cement to confirm the integrity of the barrier between the wellbore and the geologic formation); and drilling a pattern of shallow wells to intersect flow paths and recover oil before it reaches the surface. A separate seep in the Midway Sunset field is fully contained. In June 2020, the online CalGEM tracking summary of surface expressions stated that "[t]he releases in the Cymric, Midway Sunset, and McKittrick oil fields in Kern County are not near population centers *or sources of drinking water. All of the expressions are contained and are clustered in a few areas" (CalGEM 2019a). As disclosed in the 2015 FEIR, the use and disposal of produced water, as well as unintended spills and surface expressions, have the potential to impact water quality, though in the case of the spills in the Cymric, Midway Sunset, and McKittrick, no impact to sources of drinking water were found. The new UIC regulations and new CVRWQB General Orders regarding Waste Discharge Requirements seek to minimize such spills and associated impacts, as do the mitigation measures proposed below. Unrelated to potential impacts to water quality, the California Department of Fish and Wildlife stated that the Cymric incident resulted in resulted in four bird fatalities, none of which are listed as threatened or endangered under California and federal law, or identified as a bird species of special concern by the Department. CDFW 2019.*

Unplugged abandoned wells have also been found to be a source of water contamination in some parts of the United States EPA 1977. As part of SB-1281, Disclosure of Oil and Gas Water Use and Disposal operators are required to disclose the number of idle wells owned or operated by a person subject to reporting requirements. As described in Section 4.9.3, Regulatory Setting, idle and orphaned wells are regulated by the State, and seeps, spills or surface expressions from such wells are regulated pursuant to the new UIC regulations described above and in Section 4.9.3.

As described in the SB 4 Environmental Impact Report, the 2016 EPA Report discussed below (EPA 2016a), and the 2015 FEIR, chemicals used during well stimulation activities can mix with produced water as part of surface or subsurface discharges, including spills. Spills of such chemicals can also occasionally be the result of human error. The SB 4 regulations, described in Section 4.9.3, Regulatory Setting, impose significantly expanded regulatory requirements intended to regulate water quality, including disclosure of well stimulation treatment fluid chemicals and neighbor notification with the opportunity for neighbors to seek baseline water quality testing.

Many studies have investigated the effects of produced water disposal, including disposal of produced water from wells that have been subject to well stimulation treatment, on surface and/or groundwater, and studies examining whether there is a link between produced water disposal and various health effects. In part as a result of new statutory and regulatory guidance, since 2015 several new studies have been published. A general discussion of various studies is presented below. It should be noted that, as explained in the July 2015 independent scientific assessment of well stimulation activities by the California Council on Science and Technology, present-day hydraulic fracturing practice and geologic conditions in California differ from those in other states (Long et al. 2015). As such, recent experiences with hydraulic fracturing in other states do not necessarily apply to California.

Non-California Studies

- ***Kassotis, C. D. et al. (2014) Estrogen and Androgen Receptor Activities of Hydraulic Fracturing Chemicals and Surface and Ground Water in a Drilling- Dense Region.*** *– This study measured the presence of known or suspected endocrine-disrupting chemicals used for hydraulic fracturing in surface and groundwater samples in a drilling-dense region of Colorado and determined that the majority of water samples collected from sites in the heavily drilled area exhibited more endocrine-disrupting chemicals than did* *reference sites with limited nearby drilling operations. This study is not geographically or geologically relevant to well stimulation treatment activities in Kern County.*

- ***DiGiulio, D. C., and R. B. Jackson (2016). Impact to Underground Sources of Drinking Water and Domestic Wells from Production Well Stimulation and Completion Practices in the Pavillion, Wyoming.*** *DiGuilio and Jackson (2016) studied impacts to underground drinking water sources and domestic wells from production well stimulation in Pavillion, Wyoming. This study is not geographically or geologically relevant to oil and gas activities occurring in Kern County, especially considering different geological and hydrological characteristics that may exist between Pavillion Wyoming and Kern County, or the specific oil and gas practices permitted under the Ordinance and the mitigation measures required for the Project.*

General Studies

- ***U.S. Environmental Protection Agency (2016a). Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States (Final Report)*** *This study identifies certain conditions under which impacts from hydraulic fracturing activities can be more frequent or severe, including: water withdrawals for hydraulic fracturing in times or areas of low water availability, particularly in areas with limited or declining groundwater resources; spills during the handling of hydraulic fracturing fluids and chemicals or produced water that result in large volumes or high concentrations of chemicals reaching groundwater resources; injection of hydraulic fracturing fluids into wells with inadequate mechanical integrity, allowing gases or liquids to move to groundwater resources; injection of hydraulic fracturing fluids directly into groundwater resources; discharge of inadequately treated hydraulic fracturing wastewater to surface water; and disposal or storage of hydraulic fracturing wastewater in unlined pits resulting in contamination of groundwater resources. This general study does not identify these issues as being specific to California or Kern County and does not consider the role of the SB 4 regulations in addressing these issues.*

California Studies

- ***Shonkoff, S. B. C., et al. (2016). Preliminary Hazard Assessment of Chemical Additives Used in Oil and Gas Fields that Reuse Their Produced Water for Agricultural Irrigation in The San Joaquin Valley of California.*** *This study reports the preliminary findings of an analysis of the chemical data disclosed in response to the 13267 orders issued by the CVRWQCB. The preliminary analysis provides the list of chemicals reported in the context of acute mammalian and ecological toxicities, biodegradability, bioaccumulation potential, carcinogenicity, and whether chemicals are included on specific chemical priority lists. The analysis identifies potential chemicals of concern as a first step prior to more complete human health and environmental hazard and risk analyses. As described in the report, actual hazards associated with a chemical are dependent on numerous factors, including the mass of chemical used, the physical properties of the chemical, and* *many other variables that are not explored in the report of preliminary findings. The report indicates that assessing the risks associated with chemical use (e.g., the probability that a chemical or group of chemicals will cause harm) requires an understanding of the frequency, mass, and context of chemical use, including potential exposure pathways, and is beyond the scope of the technical report.*

- ***Chittick, E. A. and T. Srebotnjak T. (2017). An Analysis of Chemicals and Other Constituents Found in Produced Water from Hydraulically Fractured Wells in California and the Challenges for Wastewater Management.*** *– This study provides an aggregate chemical analysis based on data collection in accordance with California's 2013 oil and gas well stimulation law (SB 4, Pavley). The results were based on one-time wastewater analyses of 630 wells hydraulically stimulated between April 1, 2014 and June 30, 2015 and show that 95% of wells contained measurable and in some cases elevated concentrations of benzene, toluene, ethylbenzene, and xylenes and PAH compounds. The case study concludes that: (i) reporting of produced water chemical composition should be expanded in frequency and cover a wider range of chemicals used in hydraulic fracturing fluids; and (ii) produced water management practices should be oriented towards safer and more sustainable options such as reuse and recycling, but with adequate controls in place to ensure safety and reliability. The study included data collected prior to the implementation of the SB 4 regulations in accordance with the requirement that operators must develop a groundwater monitoring plan meeting the criteria of the applicable RWQCB.*

- ***Anders, R. et al. Abstract: Groundwater quality results from the Regional Monitoring Program Study of the Orcutt Oil Field, presented at California State Water Resources Control Board Stakeholder Meeting (Feb. 25, 2019) Sacramento, California, USGS.*** *This work is part of the Regional Monitoring Program authorized by California SB 4 of 2013. The Orcutt oil field, one of several large oil fields in Santa Barbara County, was identified as a high priority study area for initial sampling because relatively large volumes of fluid have been injected into the ground for enhanced oil recovery or water disposal. From 2017 to 2019, the USGS compiled information in the study area, including available groundwater and produced water quality data, water and oil well construction and geophysical records, oil field development history and injection data, and hydrogeologic features including formation geometry, groundwater flow directions, and faults. This information and new data from sampling sites adjacent to and overlying the Orcutt oil field were used to characterize the different physical and chemical properties in the Paso Robles and Careaga Formations that make up the primary groundwater aquifers in the area and the shallower unconfined to semi-confined alluvial aquifers. Results of the sampling were compared with produced-water chemistry to investigate multiple lines of geochemical evidence for the potential migration of oil-field fluids to groundwater aquifers. Mixing between oil-field fluids and groundwater was evident in four of 16 wells sampled by the Regional Monitoring Program. One well adjacent to the Orcutt oil field appeared to contain groundwater mixed with produced water based on concentrations of TDS, chloride, and dissolved organic carbon, minor-ion ratios, and the* *detection of five dissolved petroleum hydrocarbons. The same site, however, also appears to be affected by an industrial source of chemicals based on detection of 28 VOCs not associated with oil field sources. Other sites and historic data showed no evidence of oil-field fluids present in groundwater but do exhibit patterns consistent with recharge from widespread irrigated agricultural land and/or natural rock/water interactions. One factor limiting this study was the lack of wells available for sampling groundwater overlying, and in some areas adjacent to, the Orcutt oil field. The study suggested that new wells and additional monitoring of these areas in the future may yield additional insight. This study is not specific to Kern County.*

- ***McMahon, P.B. et al. (2019). Occurrence and Sources of Radium in Groundwater Associated with Oil Fields in the Southern San Joaquin Valley, California.*** *In this study, geochemical data from 40 water wells were used to examine the occurrence and sources of radium in groundwater associated with three oil fields in California (Fruitvale, Lost Hills, South Belridge). This study is not specific to Kern County.*

- ***McMahon, P.B. et al. (2017). Preliminary Results from Exploratory Sampling of Wells for the California Oil, Gas, and Groundwater Program, 2014-2015 USGS.*** *This study evaluates the utility of the chemical, isotopic, and groundwater-age tracers for assessing sources of salinity, methane, and petroleum hydrocarbons in groundwater overlying or near several California oil fields. Tracers of dissolved organic carbon in oil-field-formation water are also discussed. Tracer data for samples collected from 51 water wells and 4 oil wells are examined. In the southern San Joaquin Valley, groundwater samples were collected from 14 monitoring and water-production wells overlying or near oil fields in Kern and Kings Counties, and samples of produced water were collected from four oil wells in three oil fields in Kern County, along the west side of the valley. The data indicated that patterns of the chemicals present in groundwater derived from oil-field formations can be complex. Salts (chloride, boron, and other inorganic ions) and thermogenic methane from oil-field formations were present in some groundwater samples, whereas only salts or thermogenic methane were present in others. Hydrocarbons, such as benzene, were detected in some samples that contained modern groundwater and manufactured VOCs, and were also detected in some groundwater that appeared to be hundreds or thousands of years old and did not contain manufactured VOCs, indicating the presence of hydrocarbons both from land-surface and subsurface sources in groundwater. The study showed that thorough characterization of the chemical and isotopic composition of produced water in and between oil fields is needed to understand connections between aquifers and oil-field formations. The characterization of produced water is a component of the SB 4 regional monitoring program. Chemical, isotopic, and groundwater-age tracers examined in this study are to be incorporated into the regional monitoring program to assess the effects of oil and gas production activities on groundwater resources. Understanding the transport pathways by which chemicals from oil-field formations reached the aquifers was beyond the scope of the exploratory study, but it is important to the understanding of connections between aquifers and oil-*

field formations. Study of these transport pathways by using the tracers identified in this study is a component of the regional monitoring program.

- ***Gillespie, J.M. et al. (2019). Groundwater Salinity and the Effects of Produced Water Disposal in the Lost Hills—Belridge Oil Fields, Kern County, California.*** *This study determines the lateral and vertical extent of groundwater with less than 10,000 mg/L TDS near the Lost Hills–Belridge oil fields in northwestern Kern County, California, and documents evidence of impacts by produced water disposal within the Tulare aquifer and overlying alluvium, the primary protected aquifers in the area. Comparison of logs from replacement wells with logs from their older counterparts shows relatively higher-resistivity intervals representing the vadose zone or fresher groundwater being replaced by intervals with much lower resistivity because of infiltration of brines from surface disposal ponds and injection of brines into disposal wells. The effect of the surface ponds is confined to the alluvial aquifer— the underlying Tulare aquifer is largely protected by a regional clay layer at the base of the alluvium. Sand layers affected by injection of produced waters in nearby disposal wells commonly exhibit log resistivity profiles that change from high resistivity in their upper parts to low resistivity near the base because of stratification by gravity segregation of the denser brines within each affected sand. The effects of produced water injection are mainly evident within the Tulare Formation and can be noted as far as 550 meters (1,800 feet) from the main group of disposal wells located along the east flank of South Belridge.*

- ***Wright, M. T. et al. (2019). Groundwater Quality of a Public Supply Aquifer in Proximity to Oil Development, Fruitvale Oil Field, Bakersfield, California.*** *Wright et al. (2019) compiled historical data and collected new groundwater and produced water samples and used age data, isotopic and chemical tracers to determine mixing between groundwater and oil formation fluids. The study found that effects from oil production activities appear to be minimal and that long-term oil production has not adversely impacted groundwater, perhaps due to the rapid recharge from surface water.*

These studies demonstrate the ongoing study and analysis of the impacts of produced water disposal and well stimulation activities on groundwater. While some of the studies have limitations as noted above, they collectively provide additional evidence of the potential of oil and gas activities to violate water quality standards or waste discharge requirements, consistent with the analysis in Chapter 4.9 of the 2015 FEIR (SREIR Volume 3). This impact is addressed by compliance with applicable regulatory standards and requirements and the mitigation measures set forth below.

Mitigation Measure (MM) 4.9-1 through MM 4.9-6 from the 2015 FEIR continue to be required with the following clarifications.

MM 4.9 -1 Clarified The Applicant shall comply with all applicable federal, state, regional and local agency water quality protection laws and regulations, and commonly utilized industry standards, including (where applicable) obtaining coverage under the stormwater construction general permit and industrial general permit issued by the State Water Resources Control Board and complying with industry stormwater management standards for construction and operational activities. The applicant shall obtain all required permits from Geologic Energy Management Division ~~of Oil Gas and Geothermal Resources~~, ~~and such permits shall include measures that will safeguard protected groundwater with appropriate casing, seal and related down-hole technical specifications~~.

MM 4.9 -2 Clarified A. Oil and Gas activities in Tier I shall comply with the following.

1. In areas subject to National Pollutant Discharge Elimination System stormwater permitting requirements, project applicants shall file a Notice of Intent to the State Water Resources Control Board to comply with the statewide General Permit for Discharges of Stormwater Associated with Construction Activities (Construction General Permit State Water Resources Quality Control Board Order No 2009-009-DWO) (as such permit may be amended, revised or superseded) prior to undertaking all ground-disturbing activities greater than one acre and shall prepare and implement a Stormwater Pollution Prevention Plan for construction activities on the Project site in accordance with the Construction General Permit. For facilities requiring coverage under the Construction General Permit, the site specific Stormwater Pollution Prevention Plan shall include measures to achieve the following objectives: (1) all pollutants and their sources, including sources of sediment associated with construction activity are controlled; (2) all non-stormwater discharges are identified and either eliminated, controlled and treated, (3) site Best Management Practices are effective and result in the reduction or elimination of pollutants in stormwater discharges and authorized non-stormwater discharges from construction activity and (4) stabilization Best Management Practices to reduce or eliminate pollutants after construction are completed. The Stormwater Pollution Prevention Plan shall be prepared by a qualified preparer and shall include the minimum Best Management Practices required for the identified risk level. The Stormwater Pollution Prevention Plan shall include a construction site monitoring program that identified requirements for dry weather visual observations of pollutants at all discharge locations and, as applicable~~, appropriate~~, depending on the project risk level, sampling of site effluent and receiving waters. A qualified Stormwater Pollution Prevention Plan practitioner shall be responsible for implementing and all monitoring for the Best Management Practices as well as all inspection, maintenance and repair activities at the project site. If applicable, each project shall also implement and fully comply with the Industrial Storm Water Permit (Order No 97-03-DWO) and Kern County Municipal Stormwater Permit (Order No 5-01-120). All plans under these requirements shall be submitted to Kern County Public Works for review and approval.

2. Any operator of a facility that meets the following requirements is not required to be covered by the Construction General Permit (State Water Regional Control Board Memorandum dated 5-18-2010):

   a. discharges of stormwater runoff from oil and gas exploration, production, processing or treatment operations or transmission facilities, including field activities or operations that may be considered construction activity;

      1. are not contaminated by contact with, or do not come into contact with, any overburden, raw material, intermediate products, finished product, byproduct or waste products;

      2 are only contaminated by or only come into contact with sediment; and

      3. pursuant to 40.C.F.R. § 122.26(c)(1) (iii) that do not contribute to a violation of a water quality standard.

Any change to this State Water Regional Control Board determination will require full compliance with National Pollutant Discharge Elimination System requirements.

3. Any operator not subject to National Pollutant Discharge Elimination System stormwater permitting requirements shall implement Best Management Practices during construction and operation. All selected practices shall be shown on a drainage implementation plan and self-certified as complete ~~and feasible~~ by a licensed professional qualified in drainage and flood control issues. The plan shall be submitted to the Kern County Planning and Natural Resources ~~Community Development~~ ~~d~~Department. The following Best Management Practices shall be implemented and shown on the drainage implementation plan:

   a. Utilizing established facilities design~~,~~ and construction ~~or similar~~ standards as applicable ~~appropriate~~ (e.g., American Society for the Testing and Materials (ASTM) American Petroleum Institute (API).

   b. Implementing~~ation~~ good housekeeping and maintenance practices:

      i. Preventing trash, waste materials and equipment from construction storm water.

      ii. Maintaining wellheads, compressors, tanks and pipelines in good condition without leaks or spills.

      iii. Designing and maintaining graded pads to not actively erode and discharge sediment

      iv. Maintaining vehicles in good working order

v. Providing secondary containment for all –above –ground storage tanks and maintaining such containment features in good operating condition

c. Implementing spill prevention and response measures:

i. Utilizing preventative operating practices such as tank level monitoring, safe chemical handling and conducting regular inspections.

ii. Developing and maintaining a spill response plan

iii. Conducting spill response training for employees and have a process to ensure contractors have the necessary training

iv. Maintaining spill response equipment on site.

d. Implementing material storage and management practices:

i. Preventing unauthorized access

ii. Utilizing "run-on" and "run-off" control berms and swales

iii. Stabilizing exposed slopes through vegetation and other ~~appropriate~~ standard slope stability methods ~~(e.g., hay bales or rolls).~~

B. Oil and gas activities outside Tier 1 shall comply with all applicable state and federal stormwater management laws. For any oil and gas activity outside Tier I that is not subject to state or federal stormwater management laws, regulations or general permits, the Applicant shall prepare a drainage plan that complies with requirements to address ~~that is designed to minimize~~ runoff and ~~minimize~~ the potential for impeding or redirecting 100-year flood flows. The drainage plan shall be prepared in accordance with the Kern County Grading Ordinance, Kern County Green Code, Development Standards and approved by the Kern County Department of Public Works, Floodplain Management Section. The drainage plan shall specify best management practices to prevent all construction pollutants from contacting stormwater, with the intent of keeping sedimentation or any other pollutants from moving offsite and into receiving waters. The requirements of the Plan shall be incorporated into design specifications. Recommended best management practices for the construction phase must be shown on a drainage plan, and shall include the following:

a. Erosion Control -

1. Scheduling of construction activities to avoid rain events.
2. ~~Limiting vegetation removal to the minimum required.~~ Implementing runoff erosion control methods consistent with the drainage plan when vegetation has been removed.

b. Sediment Control -

1. Secure stockpiling of soil.
2. Installation of a stabilized construction entrance/exit and stabilization of disturbed areas.

c. Non-stormwater Control -

1. ~~Proper~~ Fueling and maintenance of equipment and vehicles shall be managed so as to prevent contamination of runoff from the site.
2. ~~Proper~~ Concrete handling techniques shall be consistent with the drainage plan and shall comply with Mitigation Measure 4.4-15(m)

d. Waste and Material Management -

1. ~~Properly~~ Managing construction materials, consistent with the drainage plan and designating construction staging areas in or around the Project site.
2. Stockpiling and disposing of demolition debris, concrete, and soil ~~properly~~ in compliance with regulatory requirements and consistent with the drainage plan.
3. Prompt removal and ~~proper~~ disposal of litter.
4. ~~Proper~~ Disposal of demolition debris, concrete and soil in compliance with regulatory requirements for solid waste.

   ~~Proper protections for fueling and maintenance of equipment and vehicles~~.

5. Provide and maintain ~~adequate~~ secondary containment to prevent ~~minimize~~ or eliminate pollutants from moving offsite and into receiving waters in compliance with Mitigation Measure 4.8-3.

e. Post-Construction Stabilization -

1. Ensuring the stabilization of all disturbed soils per revegetation or application of a soil binder.

C. If construction activities will alter federal jurisdictional waters, project applicants shall comply with the federal Clean Water Act Section 404 and Section 401 permitting and certification requirements. If construction activities will alter state waters, project applicants shall comply with California Department of Fish and Wildlife Streambed Alteration requirements.

Mitigation Measures

MM 4.9-1 The Applicant shall comply with all applicable federal, state, regional and local agency water quality protection laws and regulations, and commonly utilized industry standards, including (where applicable) obtaining coverage under the stormwater construction general permit and industrial general permit issued by the State Water Resources Control Board and complying with industry stormwater management standards for construction and operational activities. The applicant shall obtain all required permits from the Geologic Energy Management Division.

MM 4.9-2 A. Oil and Gas activities in Tier I shall comply with the following.

1. In areas subject to National Pollutant Discharge Elimination System stormwater permitting requirements, project applicants shall file a Notice of Intent to the State Water Resources Control Board to comply with the statewide General Permit for Discharges of Stormwater Associated with Construction Activities (Construction General Permit State Water Resources Quality Control Board Order No 2009-009-DWO) (as such permit may be amended, revised or superseded) prior to undertaking all ground-disturbing activities greater than one acre and shall prepare and implement a Stormwater Pollution Prevention Plan for construction activities on the Project site in accordance with the Construction General Permit. For facilities requiring coverage under the Construction General Permit, the site specific Stormwater Pollution Prevention Plan shall include measures to achieve the following objectives: (1) all pollutants and their sources, including sources of sediment associated with construction activity are controlled; (2) all non-stormwater discharges are identified and either eliminated, controlled and treated, (3) site Best Management Practices are effective and result in the reduction or elimination of pollutants in stormwater discharges and authorized non-stormwater discharges from construction activity and (4) stabilization Best Management Practices to reduce or eliminate pollutants after construction are completed. The Stormwater Pollution Prevention Plan shall be prepared by a qualified preparer and shall include the minimum Best Management Practices required for the identified risk level. The Stormwater Pollution Prevention Plan shall include a construction site monitoring program that identified requirements for dry weather visual observations of pollutants at all discharge locations and, as applicable, depending on the project risk level, sampling of site effluent and receiving waters. A qualified Stormwater Pollution Prevention Plan practitioner shall be responsible for implementing and all monitoring for the Best Management Practices as well as all inspection, maintenance and repair activities at the project site. If applicable, each project shall also implement and fully comply with the Industrial Storm Water Permit (Order No 97-03-DWO) and Kern County Municipal Stormwater Permit (Order No 5-01-120). All plans under these requirements shall be submitted to Kern County Public Works for review and approval.

2. Any operator of a facility that meets the following requirements is not required to be covered by the Construction General Permit (State Water Regional Control Board Memorandum dated 5-18-2010):

    a. discharges of stormwater runoff from oil and gas exploration, production, processing or treatment operations or transmission facilities, including field activities or operations that may be considered construction activity;

        1. are not contaminated by contact with, or do not come into contact with, any overburden, raw material, intermediate products, finished product, byproduct or waste products;

        2 are only contaminated by or only come into contact with sediment; and

        3. pursuant to 40.C.F.R. § 122.26(c)(1) (iii) that do not contribute to a violation of a water quality standard.

    Any change to this State Water Regional Control Board determination will require full compliance with National Pollutant Discharge Elimination System requirements.

3. Any operator not subject to National Pollutant Discharge Elimination System stormwater permitting requirements shall implement Best Management Practices during construction and operation. All selected practices shall be shown on a drainage implementation plan and self-certified as complete by a licensed professional qualified in drainage and flood control issues. The plan shall be submitted to the Kern County Planning and Natural Resources Department. The following Best Management Practices shall be implemented and shown on the drainage implementation plan:

    a. Utilizing established facilities design and construction standards as applicable (e.g., American Society for the Testing and Materials (ASTM) American Petroleum Institute (API).

    b. Implementing good housekeeping and maintenance practices:

        i. Preventing trash, waste materials and equipment from construction storm water.

        ii. Maintaining wellheads, compressors, tanks and pipelines in good condition without leaks or spills.

        iii. Designing and maintaining graded pads to not actively erode and discharge sediment

        iv. Maintaining vehicles in good working order

        v. Providing secondary containment for all aboveground storage tanks and maintaining such containment features in good operating condition

c. Implementing spill prevention and response measures:

i. Utilizing preventative operating practices such as tank level monitoring, safe chemical handling and conducting regular inspections.

ii. Developing and maintaining a spill response plan

iii. Conducting spill response training for employees and have a process to ensure contractors have the necessary training

iv. Maintaining spill response equipment on site.

d. Implementing material storage and management practices:

i. Preventing unauthorized access

ii. Utilizing "run-on" and "run-off" control berms and swales

iii. Stabilizing exposed slopes through vegetation and other standard slope stability methods.

B. Oil and gas activities outside Tier 1 shall comply with all applicable state and federal stormwater management laws. For any oil and gas activity outside Tier I that is not subject to state or federal stormwater management laws, regulations or general permits, the Applicant shall prepare a drainage plan that complies with requirements to address runoff and the potential for impeding or redirecting 100-year flood flows. The drainage plan shall be prepared in accordance with the Kern County Grading Ordinance, Kern County Green Code, Development Standards and approved by the Kern County Department of Public Works, Floodplain Management Section. The drainage plan shall specify best management practices to prevent all construction pollutants from contacting stormwater, with the intent of keeping sedimentation or any other pollutants from moving offsite and into receiving waters. The requirements of the Plan shall be incorporated into design specifications. Recommended best management practices for the construction phase must be shown on a drainage plan, and shall include the following:

a. Erosion Control -

1. Scheduling of construction activities to avoid rain events.

2. Implementing runoff erosion control methods consistent with the drainage plan when vegetation has been removed.

b. Sediment Control -

1. Secure stockpiling of soil.

2. Installation of a stabilized construction entrance/exit and stabilization of disturbed areas.

c. Non-stormwater Control -

1. Fueling and maintenance of equipment and vehicles shall be managed so as to prevent contamination of runoff from the site.
2. Concrete handling techniques shall be consistent with the drainage plan and shall comply with Mitigation Measure 4.14-15 (m).

d. Waste and Material Management -

1. Managing construction materials, consistent with the drainage plan and designating construction staging areas in or around the Project site.
2 Stockpiling and disposing of demolition debris, concrete, and soil in compliance with regulatory requirements and consistent with the drainage plan.
3. Prompt removal and disposal of litter.
4. Disposal of demolition debris, concrete and soil in compliance with regulatory requirements for solid waste.
5. Provide and maintain secondary containment to prevent or eliminate pollutants from moving offsite and into receiving waters in compliance with Mitigation Measure 4.8-3.

e. Post-Construction Stabilization -

1. Ensuring the stabilization of all disturbed soils per revegetation or application of a soil binder.

C. If construction activities will alter federal jurisdictional waters, project applicants shall comply with the federal Clean Water Act Section 404 and Section 401 permitting and certification requirements. If construction activities will alter state waters, project applicants shall comply with California Department of Fish and Wildlife Streambed Alteration requirements.

MM 4.9-3 All drilling operations must either use a closed loop system to avoid discharges of drilling muds and fluids, or obtain coverage under the State Water Resources Control Board low threat discharge General Order (Waste Discharge Requirements General Order 2003-0003-DWQ), obtain individual Waste Discharge Requirements issued by the Central Valley Regional Water Quality Control Board for the unit, or obtain coverage under a general order issued by the Central Valley Regional Water Quality Control Board applicable to drilling ponds. Any surface ponds or sumps must be cleared of fluids and muds in accordance with the State Water Resources Control Board general order, applicable Water Discharge Requirements and Division of Oil Gas and Geothermal Resources regulations. Compliance with the State Water Resources Control Board or Central Valley Regional Water Quality Control Board low-threat discharge orders or Water Discharge Requirements, if closed-loop systems are not used, and applicable laws, regulations and standards will reduce potential surface water quality impacts from contact with drilling muds or fluids during drilling and construction to less than significant levels.

After consultation with and approval by the Regional Water Board with jurisdiction over injection and groundwater, applicant shall provide for a tracer or some other reasonable method to allow well stimulation fluids to be distinguished from other fluids or chemicals for well stimulation permits. This could consist of an added tracer using an inert constituent that could be used to identify the presence of well stimulation fluids. Alternatively, it could be an intrinsic tracer, or some naturally occurring component that makes the well stimulation fluids chemically unique. Potential geochemical changes in the subsurface during injection or migration shall be considered. Use of a tracer shall be required to be disclosed to the public under Section 1788 of the SB 4 regulations. The regulations specifically require that the applicant require the composition and disposition of all well stimulation treatment fluids other than water, including "any radiological components or tracers injected into the well as part of the well stimulation treatment, a description of the recovery method, if any, for those components or tracers, the recovery rate, and specific disposal information for the recovered components or tracers a radiological component or tracer injected" (Section 1788 (15)). For any well stimulation treatment activity, the applicant shall not conduct well stimulation treatment activity until the State Water Resources Control Board, in consultation with the Central Valley Regional Water Quality Control Board, has approved either a groundwater monitoring plan or exclusion from groundwater monitoring for a given well, consistent with the State Water Resources Control Board Model Criteria for Groundwater Monitoring in Areas of Oil and Gas Well Stimulation.

MW 4.9-4 For any activity for which Chapter 19.98 applies, the Applicant shall not conduct any Class II injection activity regulated by the Underground Injection Control program, including enhanced oil recovery activities that discharge into any underground source of current or future beneficial use groundwater, including drinking water unless the aquifer has been exempted by the United States Environmental Protection Agency or injection has otherwise been authorized by the U.S. Environmental Protection Agency or by the California Geologic Energy Management Division in consultation and agreement by the State Water Resources Control Board, consistent with Public Resource Code 3131.

MM 4.9-5 For any activity for which Chapter 19.98 applies, the Applicant shall not discharge produced water into any surface disposal facility unless the facility has received the Waste Discharge Requirements from the Central Valley Regional Water Quality Control Board, or the need for Water Discharge Requirements has been waived by the Central Valley Regional Water Quality Control Board. As required by the SB 4 regulations, well stimulation treatment fluids and produced fluids from wells that have been stimulated cannot be stored, discharged, or disposed into surface ponds or pits.

MM 4.9-6 For any oil and gas activity within a Special Flood Hazard Area, the Applicant shall ensure that all constructed facilities are elevated or floodproofed in compliance with the requirements and standards found in the Kern County

Floodplain Management Code Ordinance and Chapters 19.50 and 19.70 of the Kern County Zoning Code.

Level of Significance After Mitigation

Less than significant with mitigation.

Impact 4.9-2: Substantially decrease groundwater supplies or interfere substantially with groundwater recharge such that the project may impede sustainable groundwater management of the basin or conflict with or obstruct implementation of a water quality control plan or sustainable groundwater management plan.

The following analysis of potential Project impacts discusses groundwater conditions in the Project Area and within each of the three subareas, each of which reflect the Project Area's primary hydrogeology. As discussed in Section 4.92, Environmental Setting, Water Supply Baseline Update, in addition to the analysis of the Project Area and subareas, each GSP and management area plan adopted for any portion of the Project Area was reviewed to identify the extent to which oil and gas operations were identified as a significant factor affecting the achievement of SGMA objectives, including groundwater supplies, recharge and implementation of a SGMA plan. None of the adopted GSPs and management areas plans within the Project Area identify oil and gas operations as a significant factor affecting the achievement of any of the SGMA objectives. Almost all of the GSPs and management area plans explicitly exclude oil and gas operational area, and exempted aquifers from SGMA-regulated groundwater basins. Several identify the potential use of treated and/or blended oil and gas produced water as a potential source of new imported water that would increase available supplies for agricultural irrigation purposes and reduce potential groundwater demand over time. For more information concerning the discussion of oil and gas activities, including produced water generation and use in each adopted GSP and management area plan in the Project Area, see Section 4.9.2, Environmental Setting, under Project Area Groundwater Sustainability Plans and Oil and Gas Activities and Appendix D of this SREIR. The following sections consider the Project's potential groundwater impacts in the context of the Project Area, each of the three subareas, and with reference to each of the GSPs and management area plans adopted in the Project Area.

As shown in Table 4.9-28, produced water generation is projected to increase from 234,959 AFY to 321,894 AFY in 2035 with the implementation of the Project. As shown in Table 4.9-27, in 2012, 88,812 AFY of produced water was reused for oil and gas activities in the Project Area, including water and steam injections, pressure maintenance and well pulling, coil tubing, dust control, and surface facility construction. The amount of produced water reused for these purposes is projected to increase to 121,412 AFY by 2035. Consequently, produced water supplies will significantly exceed and be available to meet oil and gas demand for produced water in the Project Area over time.

As discussed in Section 4.17, Utilities and Service Systems, domestic and irrigation quality oil and gas water M&I water accounts for a small percentage of total water used for oil and gas exploration and production in the Project Area. To provide a conservative assessment, this analysis assumes that all oil and gas M&I water use is provided from Project Area groundwater. The Applicant has estimated that, in 2035, oil and gas exploration and production M&I water use would have increased by 2,983 AF from 2012 levels (Table 4.9-28).

Table 4.9-28: Produced Water Generation and M&I Water Use, 2012 to 2035

	Western Subarea	Central Subarea	Eastern Subarea	Total
Produced Water Generation (AF)				
2012	131,341	2,884	100,734	234,959
2035	179,937	3,951	138,006	321,894
Increase from 2012 Levels (AF)	**48,596**	**1,067**	**37,272**	**86,935**
M&I Water Use (AF)				
2012	8,358	63	357	8,778
2035	10,851	395	515	11,761
Increase from 2012 Levels (AF)	**2,493**	**332**	**158**	**2,983**

Source: Table 39, Appendix T-1, 2015 FEIR
Note:
2035 total produced water volume assumed to be 37% above 2012 levels in each Subarea to reflect projected demand growth.
Key:
AF = acre-feet
M&I = municipal and industrial

In normal years, an estimated 1.319 million AF of groundwater was estimated to be withdrawn for various uses within the Project Area in the 2015 FEIR. In single dry and multiple dry years, groundwater withdrawals were projected to increase to 1.63 to 1.673 million AF due to the curtailment of surface supplies. In normal years, urban demand would increase from about 237,000 AFY in 2015 to 301,000 AFY in 2035. Agricultural demand was estimated to be about 2.67 million AFY (see Table 34 and Table 37 in Appendix T-1 of the 2015 FEIR). Consequently, in 2015, oil and gas exploration and production M&I water use would account for about 0.34% of all agricultural and urban water use in the Project Area and is projected to increase to about 0.4%of total Project Area agricultural and urban water use by 2035 (see Table 4.17-31 in Section 4.17, Utilities and Service Systems). Assuming all M&I use was obtained from groundwater, oil and gas consumption would account for about 0.74% of existing normal year Project Area groundwater use in 2015, and 0.90% by 2035 (see Table 4.17-34) as estimated in Appendix T-1 of the 2015 FEIR.

The volume of the industry’s 2012 M&I water consumption amounted to about 4% of the total urban water demand in 2012 (8,778 AF compared with 217,226 AF for Project Area urban uses) and would be about 3.9% of projected urban demand in 2035 (11,761 AF compared with 301,736 AF for Project Area urban uses). The analysis summarized in Appendix T-1 of the 2015 FEIR indicates that normal year Project Area water demand will be roughly equal to available supplies, with a declining margin of supply relative to demand, over time. In single dry and multiple dry years, the Project Area would experience significant supply shortfalls that could range from -315,626 AF to -817,127 AF by 2035, depending on hydrologic conditions. As noted above, these projections assume that historical levels of estimated groundwater extraction in the 2015 FEIR would continue in the future, but do not represent a safe yield or reflect SGMA groundwater use limitations in the Project Area. Under these circumstances, oil and gas exploration and production groundwater use, including an increase from 2012 levels of over 2,980 AF per year by 2035, would significantly affect available groundwater supplies in the Project Area on a Project-level and cumulative basis.

Groundwater information for the Project Area available since 2015, including the basin and subbasin boundary definitions, boundary modifications, and prioritization adopted by the DWR, the discussion of SGMA planning objectives and oil and gas in GSPs and management area plans for the Project Area, and KCS information in the GSPs, management area plans and the coordinated water budget for the KCS are consistent with the 2015 FEIR analysis of oil and gas use of produced water and M&I water supplies.

In 2017, the California legislature enacted temporary provisions codified in Water Code Sections 13808 et seq. that required the submission of certain water information in conjunction with applications to a city or county for new wells within a critically overdrafted basin. Among other information, Section 13808(a) requires that water well applicants provide information concerning the location, depth, and proposed capacity of the well; estimated pumping rates, anticipated pumping schedules, and estimated annual extraction volumes; geologic siting information; the distance from any potential sources of pollution onsite and on adjacent properties; the distance from ponds, lakes, and streams within 300 feet; existing wells on the property; the size of the area to be served by the well; and the planned category of water use, such as irrigation, stock, domestic, municipal, industrial, or other use. Section 13808.2 requires that the city or county "make the information . . . easily accessible and available to both the public and to groundwater sustainability agencies located within the basin where the new well is located, including "posting the information on the city's or county's Internet Web site . . ..'' These provisions were operative on January 1, 2018, and expired on January 31, 2020. During this period, the Kern County Public Health Services Department issued permits and water supply certificates for approximately 190 water wells and issued 374 approvals to drill water wells for property zoned appropriately and with an established use. The information required by the temporary provisions of the Water Code was provided to the KGA in accordance with Section 13808.2 of the Water Code. This change to the Water Code did not provide any additional authority to the County to regulate groundwater or limit water well permitting based on pumping information. Instead, this provision is supportive of the SGMA authority to regulate groundwater pumping and coordinate with the County on water well permitting. The baseline used in 2015 is therefore not affected by this water well information, as shown in the Supplemental Water Supply Baseline Technical Report (2020) (see Appendix D)

The GSPs for the Tule subbasin, the Tulare Lake subbasin, and the Cuyama Valley basin primarily address groundwater basins that are almost entirely outside the Project Area. None of the small portions of these GSPs that extend into the Project Area underlie an existing administrative oil field boundary or an oil and gas core area. A review of the applicable GSPs for these basins did not identify significant references to oil and gas activity, including domestic or irrigation quality groundwater use, that could affect sustainable groundwater management in the relevant plan areas. The small portion of the low-priority Carizzo Plain basin in the southwest portion of the Project Area, which does not require a GSP, also does not underlie an existing administrative oil field boundary or a core area. No GSA has been formed or GSP adopted for this basin and there is no new substantial evidence that oil and gas activity, including domestic or irrigation quality groundwater use, would affect groundwater conditions in this basin.

The portion of the low priority Kettleman Plain subbasin in the northeast portion of the Project Area, which does not require a GSP, underlies a small amount of existing administrative oil fields and Core Areas in the Project Area. Oil and gas activity in the subbasin has occurred for decades. No GSA has been formed or GSP adopted for this subbasin and there is no new substantial evidence that oil and gas activity, including domestic or irrigation quality groundwater use, would affect groundwater conditions in this basin.

The White Wolf subbasin was separated from the KCS in a basin boundary modification approved by DWR in 2016. The technical study prepared in support of the boundary modification indicates that the White Wolf subbasin had an approximate water inflow of 32,000 AFY, an outflow of about 28,500 AFY, and a net positive change in groundwater storage of 3,500 AFY. The technical study noted that oil and gas activities have historically occurred and continue to occur in the subbasin, including the production of 160,000 barrels of oil and 860,000 million cubic feet of gas production in 2014 (EKI 2016). The DWR reduced the basin's priority to medium from the high priority and critically overdrafted designations applicable prior to the approved basin boundary modification. A GSP for the White Wolf subbasin is not required until January 31, 2022. No GSP has been adopted for the White Wolf subbasin, and there is no new substantial evidence that oil and gas activity, including domestic or irrigation quality groundwater use, would affect groundwater conditions in this basin.

Five GSPs, and 15 management area plans within the KGA GSP, have been adopted for the KCS, which includes about 1.8 million acres, underlies a significant portion of the Project Area, and accounts for the vast majority of the groundwater resources in the Project Area. The GSPs and management area plans provide detailed information about discrete areas within the KCS that have been managed by established water districts, or groups of water districts and other agencies, that have significant knowledge of local groundwater conditions and management requirements within each plan area. The plans also include detailed information about groundwater in relevant locations within each of the three Subareas of the Project Area and were prepared by professional geologists or professional engineers as required by the SGMA. The plans reflect the requirements of the Coordination Agreement executed by the KCS GSAs and the coordinated water budget prepared for the entire subbasin in accordance with SGMA and the SGMA regulations.

The adopted GSPs and management area plans in the Project Area provide additional substantial evidence that oil and gas activities involving the extraction, use and disposal of produced water occur outside of aquifers subject to the SGMA. The GSPs and management area plans specifically exclude locations where producible hydrocarbons occur and exempted aquifers under the UIC program from the lateral and vertical boundaries of the groundwater subbasin in the KCS. The KGA GSP, which covers most of the Project Area subject to the SGMA and under the jurisdiction of the County, states that “active oil and gas aquifers and exempted aquifers are not a part” of the KCS “groundwater basin for beneficial use.” The annual report published by the KCS GSAs refers to the use of produced water for domestic or irrigation purposes in the KCS as a “local imported” source of “surface water from local sources imported from areas outside of the Kern County Subbasin” (KCSGSAs 2020). The WKWD Management Area Plan states that “because the regulation of oil produced water under the SGMA is not fully clear at this time” the “evaluation of oil produced water” will be reevaluated during the first five-year update the plan (Woodard & Curran 2019b). There is no substantial evidence that the exclusion of produced water from aquifers subject to the SGMA will be substantially modified in the future by any of the GSAs or in any of the GSPs and management area plans in the Project Area.

The GSPs and management area plans discuss historical areas of surface oil and gas operational discharges, including over 260 point sources and 77 active or open sites. Several of these sites include produced water discharge ponds that are subject to regulation and remediation as required in accordance with state and federal law. The WDWA Management Area plan discusses the potential down-gradient migration of high TDS groundwater to other locations in the KCS from upgradient locations where produced water ponds were located. The plan provides for continued monitoring of this potential impact in coordination with other GSAs and water districts in the KCS. (The GSPs and management area plans also discuss the regulation and protection of water quality impacts that could occur from new surface discharges. The plans indicate that applicable laws and regulations would protect water quality in the subbasin. “Surface expressions” prohibited under the April 2019 revised UIC regulations adopted by the state have occurred in the Project Area, including a large expression in the Cymric oil field. CalGEM and other state agencies have responded to these events, including the issuance of cleanup orders and the imposition of civil fines. In June 2020, the CalGEM tracking website stated that all such expressions were contained and do not affect USDWs (CalGEM 2019a). There is no substantial evidence that oil and gas activities would cause significant new or significantly greater impacts to groundwater, sustainable groundwater management, and SGMA plans in the Project Area than considered in the 2015 FEIR.

The GSPs and management area plans exclude exempted aquifers from the aquifers subject to the SGMA in the Project Area. Several of the plans discuss the potential discharge of injection fluids into aquifers that have not been exempted under the UIC. Figure 2-39 of the KGA GSP and Figure 2-39 of the HMWD-GSP show the locations of 127 wells injecting in non-oil zones with TDS concentrations that are below 3,000 mg/L and 342 wells injecting in non-oil zones where TDS greater than 3,000 mg/L and less than 10,000 mg/L derived from a 2015 list provided by the state to the EPA in accordance with an ongoing aquifer exemption review work plan. The status of the work plan was updated in a letter from CalGEM to the EPA in March 2020, which indicates that from 2017 to 2020, the EPA approved 20 aquifer exemptions, including several within the Project Area and encompassing many of the wells identified in the GSPs. Several other aquifer exemption proposals are being reviewed and considered by CalGEM, including locations in the Project Area (CalGEM 2020d). The March 2020 CalGEM letter states that the ongoing implementation of the aquifer exemption work plan "continues to demonstrate the State's commitment to protecting public health and the environment while avoiding unnecessary disruption of oil and gas production." A lawsuit against the aquifer exemption work plan was dismissed in 2016 by the California Superior Court, and the decision was upheld by the California Court of Appeals in 2018 (*Center for Biological Diversity v. California Department of Conservation,* [2018] 26 Cal. App. 5th 161). There is no substantial evidence that oil and gas activities related to the ongoing aquifer exemption work plan would cause significant new or significantly greater impacts to groundwater, sustainable groundwater management or SGMA plans in the Project Area than considered in the 2015 FEIR.

Oil and gas related subsidence is not identified as a significant factor affecting groundwater subject to the SGMA in the GSPs and management area plans in the Project Area. The Coordination Agreement includes the implementation of a monitoring network in the KCS, and several GSPs and management area plans note that the network could detect subsidence in oil and gas operational areas. Any such detection would be reported to and subject to regulation by CalGEM in accordance with Public Resources Code Section 3315. There is no substantial evidence that subsidence related to oil and gas activities would cause significant new or significantly greater impacts to groundwater, sustainable groundwater management and SGMA plans in the Project Area than considered in the 2015 FEIR.

The GSPs and management area plans adopted in the Project Area, and the coordinated water budget required by the SGMA, provide quantified water demand estimates and projections for urban uses based on per capita water use date, and agricultural demand based on evapotranspiration and crop information in the Project Area. The annual report submitted to DWR by the KCS GSAs in April 2020 and the coordinated water budget indicate that oil and gas industry demand is included in the estimates of urban water use. The WDWA Management Area plan states that a "small portion of the SWP surface water supply mainly used for agriculture in the GSA is sometimes delivered as industrial water to agricultural processors and oil field production customers" and that "a percentage of the annual allocation from the SWP is delivered for industrial use in oil recovery operations in the North and South Belridge oil fields." Most of the other GSPs and management area plans do not discuss oil and gas water use. The quarterly water use reports published by CalGEM indicate that from the second quarter of 2015 to the second quarter of 2017, the period for which state data reviewed and compiled by CalGEM was available, statewide oil and gas use of domestic and irrigation quality water for injection purposes averaged 1,550 AF per quarter and 641 AF were used for non-injection and storage purposes (see Section 4.17, Utilities and Service Systems). These data indicate that over four quarters, the use of domestic and irrigation quality water by the state's oil and gas operations averaged about 8,764 AFY. The CalGEM quarterly water use reports cover 90% of the state, and oil and gas production in the Project Area accounts for about 80% of total California production. There is no substantial evidence that oil and gas use of domestic and irrigation quality water in the Project Area would cause significant new or significantly greater impacts to groundwater, sustainable groundwater management, and SGMA plans in the Project Area than considered in the 2015 FEIR.

In contrast with water demand, new information available since 2015 provides substantial evidence that oil and gas activities could support sustainable groundwater management in the Project Area to a greater extent than considered in the 2015 FEIR. As discussed in Section 4.17, Utilities and Service Systems, the coordinated water budget for the KCS covering a 50-year planning and implementation horizon from 2021 to 2070 has been prepared by the KCS GSAs in accordance with the SGMA regulations. The water budget considers water supply and demand in the KCS under baseline, climate change 2030, and climate change 2070 scenarios. The scenarios utilize sequences of drier and wetter water years that are representative of historical average conditions in the KCS and include varying assumptions concerning surface water supplies in response to regulatory and climate change impacts over time. The coordinated water budget compares the average annual change in KCS stored groundwater during the SGMA sustainability period of 2041 to 2070 with historical changes and with and without the implementation of SGMA Projects to enhance the subbasin's water budget. The coordinated water budget indicates that KCS groundwater in storage declined by an average of approximately -277,000 AFY from 1995 to 2014. The annual decline in stored groundwater would increase in each of the three scenarios without the SGMA Projects to an annual average of -324,326 in the baseline scenario, -380,900 in the climate change 2030 scenario, and to -489,828 in the climate change 2070 scenario from 2041 to 2070.

The adopted GSPs and management area plans identify multiple SGMA Projects that would improve the KCS water budget by approximately 421,000 AFY over the 50-year SGMA planning and implementation period. Several of the SGMA Projects contemplate the expanded use of produced water to enhance available supplies in the KCS. As discussed above, the GSPs and management area plans in the Project Area do not include produced water in the aquifers subject to the SGMA. The annual report submitted by the KCS GSAs to the DWR in April 2020 refers to produced water used for domestic or irrigation purposes as a local surface water imported supply (see Section 4.17, Utilities and Service Systems). As a result, projects that expand the availability of produced water for domestic or irrigation use increase the net water supply subject to the SGMA in the Project Area. The SGMA Projects in the adopted GSPs and management area plans that would increase produced water use in the KCS include the following:

- Reclamation of oil field produced water to develop new supplies estimated at 1,000 AFY in the AEWSD plan.
- Potential development of 7,000 to 20,000 AFY of new produced water supplies in the CWD GSA Management Area plan.
- Construction of a pipeline for conveyance and blending of up to 3,000 AFY of new produced water supplies in the KTWD Management Area plan.
- Recycling oil field produced water for agricultural use in the EWMA plan.
- Potential treatment and use of up to 50,000 AFY of brackish groundwater and produced water for beneficial reuse in two construction phases over 10 to 20 years in the WDWA Management Area plan.

The coordinated water budget indicates that the implementation of the SGMA Projects will result in an average annual change in stored KCS groundwater of +42,000 AFY in the during 2041 to 2070 in the baseline scenario, and would increase to +85,578 AFY when adjusted for excess basin outflows. The average annual change in groundwater storage in the 2030 climate change scenario with the SGMA Projects will improve to -12,861 AFY during 2041 to 2070 and increase to +46,829 AFY when adjusted for excess outflows. The average annual change in groundwater storage in the 2070 climate change scenario will improve to -118,273 AFY during 2041 to 2070 compliance period further decline to -45,969 AFY when adjusted for excess outflows. The coordinated water budget provides substantial evidence that the availability and reuse of produced water from oil and gas operations would support sustainable groundwater management and SGMA plan implementation in the KCS over the 50-year SGMA planning and implementation horizon.

Produced water has historically been used in the Project Area, mainly for irrigation. This use is discussed in several of the GSPs and management area plans for the KCS, including the Cawelo GSA Management Area plan, the KTWD Management Area plan and in the NKWSD – SWID Management Area plan. The quarterly water use reports for state oil and gas operators published by CalGEM indicate that from the second quarter of 2015 to the second quarter of 2017 California oil and gas operators sold or transferred an average of 8,991 AF of produced water per quarter for domestic use (CalGEM 2020d). These data indicate that over four quarters, the average sale or transfer of produced water for domestic and irrigation use was about 35,964 AFY (see Section 4.17, Utilities and Service Systems). As noted above, the CalGEM quarterly water use reports cover 90% of the state, and oil and gas production in the Project Area accounts for about 80% of total California production.

The coordinated water budget and the descriptions of the SGMA Projects in applicable GSPs and management area plans suggest that oil and gas activities could provide sufficient new supplies and offset the industry's anticipated use of domestic and irrigation quality water. Under these conditions, oil and gas activities would have a positive impact on groundwater management in the Project Area and no mitigation measures would be required.

<u>*However, as discussed in Section 4.9.3, Regulatory Setting, Produced Water Reuse for Agricultural Irrigation, several factors could constrain the use of produced water for irrigation. As discussed in Section 4.9.2, Environmental Setting, SGMA Overview, the plans are specifically intended to be adaptively managed in response to continual basin monitoring and analysis, including the development of new measures if necessary and management that would reduce potentially significant social and economic harm. The SGMA by its terms provides the GSAs with a 20-year period, including the periodic reassessment and modification of applicable GSPs and management area plans, to comply with the Act.*</u> The SGMA Projects~~, *however*,~~ are proposed approaches for avoiding undesirable results in conjunction with long-term plans that will be adaptively managed and modified as required to address changing conditions. It is possible that the additional produced water reuse discussed in the GSPs and management area plans, or other SGMA Projects that may be proposed for produced water reuse in the future, will prove to be technologically or economically infeasible. Several of the GSPs and management area plans include feasibility studies to assess these issues, including the AEWSD Management Area plan, the CWD GSA Management Area plan, and the WDWA Management Area plan. As discussed in

Section 4.17, Utilities and Service Systems, oil and gas operations in the Project Area are significantly influenced by regulatory and global market factors and have varied substantially from 2014 to 2020. The CWD GSA Management Area plan, which includes a portion of the Project Area where produced water has historically been used for irrigation, states that "[t]he volume of treated produced water will fluctuate with oil production and long-term availability cannot be predicted" (Cawelo GSA 2019). Produced water reuse contemplated by applicable GSPs and management area plans through 2070 would not occur if oil and gas operations significantly contract due to regulatory or market constraints over this period. There is also substantial evidence of ongoing opposition to treated produced water reuse based on perceived health and safety concerns, as discussed in *the CVRWQCB draft Food Safety Project report (CVRWQCB 2019a) and in* a peer-reviewed study published in May 2020 by researchers from Duke University and RTI International (Duke University 2020). Although *the CVRWQCB and SWRCB have not found any evidence of elevated health and safety risks from the use of produced water for irrigation in accordance with applicable permits and approvals, and* the study determined that produced water reuse did not result in salts, metals, and naturally occurring radioactive materials contamination in the CWD, it is reasonably foreseeable that perceived health and safety concerns may result in continued opposition to treated produced water reuse in the Project Area. ~~*Consequently, while it is possible that oil and gas operations will generate a net increase in domestic and irrigation quality water as the SGMA is implemented in the Project Area, it is also possible that the supply of treated produced water will be curtailed by regulatory and economic factors. There is no substantial evidence that expanded treated produced water reuse will occur in the Project Area in predictable volumes over time.*~~

Consequently, while it is possible that oil and gas operations will generate a net increase in domestic and irrigation quality water as the SGMA is implemented in the Project Area, it is also possible that the supply of produced water will be curtailed by regulatory and economic factors, or that such reuse will be technologically, economically, or environmentally infeasible. There is no substantial evidence that produced water will continue to be utilized and that expanded produced water reuse will occur in the Project Area in predictable volumes over time. As a result, the projected increase in the oil and gas industry's domestic and irrigation quality water use of 8,778 AFY to 11,761 AFY represents the potential impact to groundwater attributable to the Proposed Project. Due to the unavailability of surplus water in the Project Area, which is also demonstrated by the increasingly negative changes in the annual amount of stored groundwater projected for 2021 through 2070 without the SGMA Projects in the KCS coordinated water budget *(see Section 4.17, Utilities and Service Systems)*, oil and gas consumption of domestic and irrigation quality water would have a significant impact and contribute to a significant cumulative impact to sustainable groundwater management and SGMA plan implementation in the Project Area.

CEQA requires that the lead agency identify feasible mitigation measures to reduce impacts determined to be significant. Under CEQA, mitigation is feasible if it is capable of being accomplished in a successful manner within a reasonable period of time, taking into account the economic, environmental, legal, social, and technological factors.

The 2015 FEIR determined that no feasible mitigation could reduce significant groundwater and water supply impacts to less than significant levels. Three mitigation measures, MM 4.17-2 to 4.17-4, were identified to reduce significant impacts, primarily by encouraging greater produced water reuse and reduced domestic and irrigation water use by oil and gas operators. As discussed in Section 3.1, Project Overview, of this SREIR, the Appellate Court determined that these mitigation measures violated CEQA because they did not require or result in predictable oil and gas domestic and irrigation quality water use reductions, and because they did not provide the provide the County Board of Supervisors with sufficient information concerning the net impact to groundwater and water supplies when the Board adopted a Statement of Overriding Considerations for these impacts.

As discussed above in Section 4.9.2, Environmental Setting, the County withdrew from the KGA in 2018 and does not participate in the SGMA management of the Project Area. *As discussed in Section 4.9.2, Environmental Setting, SGMA Overview, the SGMA presumes that* GSAs in the Project Area ~~have~~ *are the* exclusive *local agencies* for ~~*sustainable groundwater management*~~ *implementing SGMA in accordance with duly adopted GSPs. The adopted GSPs and management area plans state that each plan reflects this exclusive jurisdiction, and the KGA GSP further provides that the member agencies in the KGA GSA have the sole responsibility for implementing SGMA within each management plan area.* ~~*under the*~~ SGMA *provides the GSAs with regulatory authority to implement several actions, including potential regulation of groundwater withdrawals from individual wells or all wells in an entire basin. The SGMA further requires that each GSA develop GSPs and management area plans that consider the interests of all beneficial uses and users of groundwater, as well as those responsible for implementing GSPs and including surface water users, if there is a hydrologic connection between surface and groundwater bodies. In basins and subbasins like the KCS, where multiple GSAs have been formed and multiple GSPs and management area plans have been adopted, the SGMA requires that the GSAs implement the applicable plans in accordance with a coordination agreement that will result in a comprehensive, sustainable management solution for the entire basin or subbasin. The SGMA requires that the technical hydrogeological and water budget information used by the GSAs to implement the* GSPs and management area plans *and to provide the common, basin-wide information in accordance with the coordination agreement,* ~~*adopted by the GSAs and*~~ *must be* prepared by professional geologists and engineers in accordance with the SGMA regulations ~~*include SGMA Projects that could increase produced water reuse in the KCS*~~. The *adopted GSPs and management area plans include several proposed measures that could increase water supplies, or potentially reduce demand, but the* feasibility of these SGMA Projects ~~*is being*~~ *is subject to adaptive management, including* evaluat*ion and revision in response to monitoring and at regular intervals over the 20-year period for compliance created by the Act.* ~~*, ed in the context of the SGMA in the Project Area.*~~ *The SGMA is a novel locally based approach to long-term groundwater sustainable management and requires that undesirable results be avoided by implementing comprehensive solutions for each applicable basin and subbasin. The formation of GSAs, the adoption of GSPs and management area plans, the development of technical hydrological information at a basin, subbasin and plan level, and the consideration and integration of a wide range of interests affected by groundwater as defined in the SGMA legislation has never before been attempted in California. The adopted GSPs in the Project Area represent initial approaches for implementing the SGMA* that will be adaptively managed and revised as necessary to comprehensively meet SGMA requirements over the statutory 20-year compliance period and a 50-year planning and implementation horizon. ~~The County has substantially less capacity to identify and implement mitigation measures that would predictably increase the reuse of produced water than the GSAs and the management entities implementing the GSPs, management area plans, and SGMA Projects in the Project Area. It is possible, moreover, that any such measures could conflict with and adversely affect the development of SGMA Projects as the GSPs and management area plans are implemented over time. Due to these considerations, there are no feasible mitigation measures that would result in predictable volumes of produced water reuse and reduce the Proposed Project's significant impacts to sustainable groundwater management and SGMA plan implementation.~~

The following sections discuss the feasibility of potential mitigation measures for groundwater supply and SGMA planning impacts.

The County could potentially implement a mitigation measure that requires the additional reuse of produced water for agricultural irrigation to offset Project impacts to higher-quality M&I water supplies. As discussed above in Section 4.9.2, Environmental Setting, Project Area Groundwater Sustainability Plans and Oil and Gas Activities, and in Appendix D, several GSPs and management area plans include potential SGMA Projects that would, if successfully implemented, increase produced water imports for beneficial use in SGMA planning areas. None of the plans, however, indicate that any such increased reuse will be feasible; several, including the Cawelo GSP, explicitly state that the amount of produced water available for reuse in the future cannot be predicted due to potential regulatory and technical feasibility constraints. At present, the potential expansion of produced water reuse included in GSPs and management area plans are subject to ongoing feasibility studies to determine whether increased produced water supply imports can be achieved.

As discussed in Appendix D and Section 4,17, Utilities and Service Systems of this SREIR, in late 2019 and early 2020, state regulators indicated that they wish to curtail oil and gas activities in California. In recent years, the oil and gas industry has experienced lower prices, including a brief period in 2020 when spot market futures for oil turned sharply negative for the first time in history. The County cannot mandate that oil and gas operators generate produced water in predictable amounts over time, and has no authority or control to regulate state policies or national and international conditions affecting industry operations, including produced water generation. As discussed in Section 4.9.3, Regulatory Setting, Produced Water Reuse for Agricultural Irrigation, although there is no evidence to date that permitted produced water reuse for irrigation in the Project Area has caused health or safety issues, there is continued opposition to and concern about such reuse. Since 2015, the CVRWQCB has created an ongoing Food Safety Project, including an expert panel, to continue to evaluate and assess these concerns. It is possible that, even if additional amounts of produced water imports for irrigation are technically and economically feasible to generate and available in the future, health and safety concerns would preclude such use. Given these considerations, the implementation of a mitigation measure to offset oil and gas M&I water use with predictable amounts of produced water reuse is infeasible.

The County could implement a mitigation measure to reduce potential Project groundwater impacts by limiting the amount of oil and gas activity in the Project Area through a permit quota or similar measure. Alternatively, the County could ban the use of higher quality water supplies for certain oil gas operational activities, such as steam production for enhanced oil recovery, well completion, and other operations. These measures are infeasible for several reasons.

First, as discussed in Chapter 6.0 Alternatives, any such measures would expose the County to substantially significant liability for regulatory taking claims, including significant litigation costs and related budgetary and County operational and management uncertainty involved in resolving any such claims. Second, the County has no jurisdiction over groundwater allocations and simply reducing the number of oil and gas wells drilled may not actually reduce groundwater used. The groundwater being used by the oil companies primarily comes from water districts who will then move the water to another use in the basin. The determination of which land use should use water and which land use should be restricted from using water is a policy decision for the Kern County Board of Supervisors and not a CEQA determination. The impacts have been clearly discussed in the SREIR, and all feasible and reasonable mitigation has been included. Given the basin's characteristics, any use of groundwater will be considered significant and unavoidable.

~~*The County could potentially implement a mitigation measure that would ban the use of domestic or irrigation quality water by oil and gas producers. Any such mitigation measure would be infeasible for several reasons.*~~ *Although MM 4.17-2 to 4.17-4 from the 2015 FEIR sought to increase the use of additional produced water and reclaimed water in place of M&I quality water, there is no substantial evidence that treatment technologies and distribution systems in the Project Area can be feasibly developed and operated in a manner that would reduce M&I water use by oil and gas operators in a predictable manner over time and without causing other significant environmental impacts. During 2016 to 2019, when MM 4.17-2 to 4.17-4 were in effect, certain of the Applicants were able to implement measures implemented to reduce oil and gas use of higher quality M&I water, and additional measures were planned for future periods (WSPA 2020). While this information shows that it may be possible to encourage reduced M&I water use, it does not demonstrate that any such reduction can be feasibly implemented in a manner that will reduce Project water supply impacts to a predictable extent and on a widespread basis throughout the Project Area.*

Certain oil and gas operations, such as well drilling and abandonment work, require high quality water to properly formulate the cement mixtures that are needed to safely drill and abandon wells. Steam generation required for oil and production can also require higher quality water supplies than are typically obtained from treated produced water in order to avoid equipment corrosion or damage and potential chemical interactions. Use of produced water in certain oil and gas operations can also lead to increased need for equipment maintenance due to, for example, silica buildup or tube failures in boilers. Using untreated or lower quality produced water for these activities would jeopardize the operators' ability to comply with regulatory requirements applicable to well construction and abandonment and the safe operation of oil field equipment, including the avoidance of corrosion.

The use of produced water for well stimulation treatments would also significantly increase chemical use as well as costs. Chemicals used in fracture treatments impart viscosity for proppant transport and fracture geometry creation and improve post-treatment production results by minimizing polymer plugging and other phenomena detrimental to production. Using produced water instead of freshwater as a base fluid for fracture treatments would increase the chemical volumes needed to fulfill these functions. Produced water use for fracture treatments could require as much as a five-fold increase in buffering agents, and additional chelating agents, clay and scale inhibitors, and surfactants to prevent emulsions and reduce surface tension may also be needed to minimize production complications that would be caused by the use of produced water. While produced water could be pre-treated to require fewer chemicals during the fracture treatment itself, such pre-treatment conditioning would also involve more chemicals, equipment, or both, to obtain water sufficient for use in the fracture treatment. Because of these complications, a typical fracturing operation would become significantly more expensive, and often uneconomic. In addition, for some types of well stimulation, such as matrix acid stimulation, it is technologically infeasible to utilize produced water. Typically, matrix acid stimulation employs hydrofluoric acid, which can only be mixed with freshwater. If hydrofluoric acid comes into contact with formation brine, insoluble precipitants form, limiting the effectiveness of the acid stimulation system by plugging pore throats in the reservoir pore network. Such plugging can completely counteract the effects of the stimulation treatment. The reduction in the effectiveness of the treatment would require more frequent treatments, larger treatments, or both, which would lead to a significant increase in use of chemicals, emissions and heavy vehicle traffic hauling hazardous chemicals.

Produced water is currently used for some oil field activities, such as discharge for dust suppression, but increasing that use beyond existing levels would require additional permitting and approvals to avoid impacts to biological, water and other resources. Additionally, the lack of infrastructure linking sources of produced water to the locations where water may be used, particularly in cases of new exploration, can result in increased truck trips and other more significant impacts associated with transporting produced water to operation sites. For example, pilot EOR projects typically cannot use recycled water due to the early stage of project development, which results in a lack of available recycled water *that can be obtained from recycled water suppliers using existing, or feasibly expanded, treatment and distribution facilities*. Furthermore, the treatment of water for reuse requires specialized equipment, consumes energy, and generates waste. In many cases, operators have also contracted with local water purveyors to utilize some supply of purchased water over a long-term contract; cancellation of such contracts would also create negative financial impacts for the region.

As discussed above, most of the use of M&I supplies for EOR occur in the Western Subarea because existing water quality is particularly poor in that portion of the Project Area. A feasible method for treating and distributing treated local low quality water or produced water for widespread EOR use has not been identified in that region. As summarized above in Section 4.9.2, Environmental Setting, under Project Area Groundwater Sustainability Plans and Oil and Gas Activities, certain of the GSP and management area plans, including the WDWA, have proposed SGMA Projects that could treat local groundwater or produced water with several potential technologies to enhance local supplies. However, the WDWA GSP specifically states that the feasibility of any such treatment and reuse is under investigation. Unresolved issues cited in the *plan and that are subject to a feasibility study include "regulatory acceptance, potential for undesirable results (e.g. significant subsidence), and for the economics of treating both brackish groundwater and oil field produced waters in a distributed modular facility via the use of readily available membrane technologies, such as reverse osmosis (RO). Treatment technologies to be assessed would include pre-treatment, pH adjustment and filtration followed by either a single-pass RO configuration, a double-pass RO, or a RO modification called a closed-circuit RO." (Aquilogic 2019)*

The plan further states that the feasibility study includes "Evaluating existing hydrogeologic data pertaining to brackish groundwater and oil field produced water quality, water use, and volumes; Development of preliminary engineering options and costs for siting the treatment facility, source wells, water treatment, energy demand, concentrate disposal, and treated water transmission; Examination of the potential for undesirable results (e.g. subsidence); and Assessment of permitting and public notification requirements (California Environmental Quality Act [CEQA], etc.)" (Aquilogic 2019). In addition, the plans states that a "project alternative analysis will be performed leading to a recommended plan for implementation including a preliminary construction schedule and financing plan, a revenue program, and a net present worth analysis." The WDWA management plan has a "goal to have the first modular treatment system online before the end of the second five-year [GSP] reassessment period (by 2030)" (Aquilogic 2019). There is no substantial evidence that the ongoing feasibility study will result in any amount of local water or produced water treatment sufficient to supply any or a predictable amount of oil and gas industry M&I water requirements, including EOR, in the Project Area. Similarly, none of the other GSPs and management area plans provide any evidence that additional amounts of produced water can be feasibly and reliably imported for use in SGMA regulated basins and subbasins in the Project Area.

In response to a domestic and irrigation quality water use ban, oil and gas operators in the Project Area would likely attempt to treat additional amounts of produced water to domestic or irrigation quality for activities that require higher quality water supplies. ~~*As discussed in the GSPs and management area plans, including the CWD GSA Management Area plan and the WDWA Management Area plan, this treatment would require technologies, such as reverse osmosis, with significant capital and operational costs.*~~ Many Project Area oil and gas operators lack the technological expertise and economic capacity to treat produced water. A domestic and irrigation quality water use ban could reduce or preclude oil and gas activities and generate adverse economic and social consequences in the County. The curtailment of oil and gas operations that generate produced water could also conflict with the implementation of SGMA Projects in the adopted GSPs and management area plans for the KCS that would use produced water supplies. *The potential reduction in the availability of produced water for irrigation reuse is specifically cited in the Cawelo GSA management area plan as factor that precludes the plan's ability to project that historical or anticipated produced water imports will in fact be available in future years.* The County does not have ~~*produced*~~ water treatment and distribution facilities sufficient to produce~~d~~ and deliver higher quality water to oil and gas operators throughout the Project Area. As a result, higher quality water would need to be generated in new, energy intensive facilities and delivered by truck to most of the Project Area, which would require additional permitting processes to avoid adverse secondary environmental impacts, including increased energy and vehicular use and greenhouse gas emissions.

Due to the risks of chemical interactions adversely affecting health, safety, and equipment integrity that would result from using produced water for certain operations, the additional delivery infrastructure, truck trips, and brine disposal required to generate higher quality supplies from produced water, technological, and economic challenges, and the likelihood of adverse social and economic impacts in the County, the complete elimination of domestic and irrigation quality water by oil and gas operators in the Project Area is economically, socially, environmentally, and technologically infeasible.

As summarized in Section 4.9.2, Environmental Setting, Project Area Groundwater Sustainability Plans and Oil and Gas Activities, the adopted GSPs and management area plans in the Project Area identify several SGMA Projects that could increase water supplies, reduce demand, or otherwise facilitate the achievement of SGMA objectives within the 20-year statutory time frame for compliance. The County could implement a mitigation measure that would require oil and gas operators permitted under the proposed Project to pay a fee that would be used to ~~*develop produced water treatment facilities and enhanced reuse in the Project Area*~~ *implement one or more of these SGMA Projects to reduce or avoid Project groundwater impacts. This mitigation approach is infeasible for several reasons.* ~~*The imposition of a fee is infeasible for several reasons. The County lacks the expertise and technical capacity to implement and manage a produced water treatment and distribution system in the Project Area. Consequently, fees collected from oil and gas applicants would need to be provided to other entities that have a demonstrable capacity to operate and manage produced water treatment and distribution facilities with sufficient capacity and scope to serve the Project Area.*~~

As discussed ~~*above,*~~ *in Section 4.9.2, Environmental Setting, SGMA Overview, the GSPs and management area plans adopted in the Project Area represent the first step towards implementing a novel, complex and historically unprecedented locally-based sustainable groundwater management program. The plans focus on adaptive management to respond to the multiple interests affected by the comprehensive groundwater management required by the SGMA, and to adjust initially proposed SGMA Projects during successive plan refinements as needed over the statutorily created 20-year SGMA compliance period. The need for adaptive management and implementation flexibility in the SGMA process, and the need for planning adjustments over time, has been noted in publications by both SGMA practitioners and academic researchers (Montgomery & Associates 2020; Escriva-Boua 2020). There is no assurance that any specific SGMA Project, including expanded produced water treatment and reuse discussed above, will result in water supply increases or demand reductions that would predictably reduce or avoid Project groundwater impacts. Academic studies have indicated that, based on statistical models, increased groundwater pumping restrictions increase the likelihood of successfully reducing overdrafts in California. (Escriva-Boua 2020.) The County has no authority to directly regulate or control groundwater pumping, and the SGMA provides such authority only to duly-formed GSAs that adopt a GSP in accordance with the Act.*

Comments have asserted that County could indirectly attempt to reduce water demand in the Project Area by purchasing and fallowing agricultural land, and retiring the water use a potential SGMA Project discussed in several GSPs and management area plans. However, the fallowing programs the GSAs are implementing do not completely retire the water but repurpose it for more productive lands. There is no evidence that any fallowing program proposed in the valley intends to stop all use of water from the fallowed lands. Instead, the fallowing program takes land with some small allocation but not enough to farm productively and then retires that land and aggregates that water to other more productive fields. This prevents the fallowed land from attempting to purchase surface water that could be used for banking or other recharge purposes to make up the difference or use the land for a more intensive water use development. This suggested mitigation further n presupposes willing sellers of such land who have not already made agreements with their own water districts. The GSAs and individual water districts in Kern are already acquiring land and working with agricultural land owners to ensure the preservation of productive land. CEQA does not require that a Lead Agency create new programs that are already being implemented by other regulatory agencies. Further, higher-quality water supplies, including groundwater, that are used in oil operations and bought from a water district already include the costs of implementation of any fallowing program. CEQA does not give a Lead Agency the ability to impose costs that are already being assessed for the same purpose. The implementation of fallowing and similar demand reduction for Project mitigation purposes would also conflict with the express objectives of adopted GSPs in the Project Area, such as the Kern River GSP, which specifically states that "demand reduction projects could have a detrimental impact on the local economy, livelihood of residents and business owners, and the well-being of Metropolitan Bakersfield and Kern County. Therefore, large-scale reductions are not proposed in Phase One and may be unnecessary for achieving the sustainability goal. At a minimum, such actions are delayed until later in the implementation period to allow water supply projects the opportunity to sustainably support current and projected growth in the beneficial uses of groundwater" (KRGSA 2020).

Similarly, agricultural fallowing would conflict with the KGA GSP's express concerns that SGMA plans be adaptively managed because "The communities, the economy, and local governments are and have been reliant on Kern County agriculture and are dedicated to preserving the viability of agriculture into the future" (KRGSA 2020). Finally, it is not clear that fallowing and similar demand reduction measures by curtailing Project Area water use by itself would reduce water demand without additional restrictions. Growers that have not ceased operations, for example, may be induced to increase irrigation or plant more remunerative crops with higher water demands in response to the fallowing of adjacent formerly operating farmland. Other SGMA Projects, such as expanded produced water reuse are discussed above and are subject to similar uncertainty concerning feasibility and predictable water supply mitigation effects.

The SGMA requires, and was designed by the legislature to achieve, a comprehensive sustainable groundwater management solution for high priority basins and subbasins implemented over a 20 year period by legislatively authorized, newly created local agencies (GSAs) implementing, where applicable, coordinated GSPs and management area plan. The precise supply enhancement, demand reduction and other SGMA Projects that will be required to achieve SGMA requirements in the Project Area are yet to be determined and will require the balancing of multiple interests, *the use of still-developing technical information, and adaptive management in response to long-term monitoring to achieve. As stated in the Kern River GSP, this process is being explicitly managed to avoid detrimental impacts to the local economy, livelihood of residents and business owners, and the well-being of Metropolitan Bakersfield and Kern County, to the extent possible. It is virtually certain that the SGMA process, including the identification and implementation of SGMA Projects, will be significantly modified during successive GSP and management plan five-year reviews, during the 20-year compliance period, and over the 50-year planning and implementation horizon mandated by the SGMA and the SGMA regulations.*

Based on these considerations, the County will implement two water supply mitigation measures to ensure that Project-related groundwater use is integrated with the comprehensive SGMA compliance process in the Project Area.

MM 4.17-3 requires that all Oil and Gas Conformity Reviews and Minor Activity Reviews disclose whether any groundwater or reclaimed water will be used for the proposed oil and gas activity. Groundwater may only be used from wells equipped with a water meter. All applicants will be required to provide the specific details on water use when the permit is submitted that includes: (1) the source and estimated amount of any groundwater being used in the permitted activity; (2) confirmation that any water well that provides any groundwater used for a permitted activity is metered; and (3) the source and estimated amount of any reclaimed water used in the permitted activity. This information will be compiled into a report by the Kern County Planning and Natural Resources and posted on the department website by December 31 of each year. It will also be sent directly to the all GSAs and the Kern County Water Agency for informational purposes.

MM 4.17-4 requires the county to provide public notice of any Conditional Use Permit (CUP) to all GSAs in the valley for review and comment.

W~~hile several of the GSPs and management area plans contemplate SGMA Projects that would expand produced water reuse, no new produced water treatment or distribution facilities as contemplated in one or more SGMA Projects have been constructed or are operating in the Project Area. Most of the SGMA Projects involving produced water are subject to ongoing or proposed feasibility studies that have not been completed. As discussed above, and also in the WDWA Management Area plan, produced water treatment and distribution could have several significant environmental impacts such as greenhouse gas emissions and concentrated brine disposal that will need to be fully evaluated.~~

~~In the absence of an established produced water treatment and distribution program in the Project Area, there is no substantial basis for determining that the collection of water fees from oil and gas applicants will result in predictable reductions of oil and gas domestic and irrigation quality water use. The imposition of a new fee, however, would increase costs for oil and gas producers, particularly smaller operators, and could result in operational curtailment in the Project Area. The curtailment of oil and gas operations that generate produced water could conflict with the implementation of SGMA Projects in the adopted GSPs and management area plans for the KCS that would use produced water supplies. A reduction in oil and gas activities would also generate adverse economic and social consequences in the County. The payment of a fee to enhance~~

~~*produced water reuse in the Project Area is economically, socially, environmentally, and technologically infeasible.*~~

MM 4.17-3 and 4.17-4 will support the implementation of the SGMA in the Project Area. ~~*Based on these considerations*~~, *As discussed above,* there are no *other* feasible mitigation measures that would reduce Project's significant *groundwater and* sustainable groundwater management impacts to a reasonably predictable extent. It is possible that, consistent with the adopted GSPs and management area plans in the Project Area, additional produced water will be used to supplement supplies in the KCS and in other locations over time. While this outcome would support rather than impact sustainable groundwater management and SGMA plan implementation in the Project Area, SGMA Projects that would increase produced water reuse have yet to be implemented by the GSAs with statutory authority for ~~*managing groundwater*~~ *implementing SGMA* in the Project Area. Accordingly, oil and gas demand for domestic and irrigation quality water is projected to increase from 8,778 AFY to 11,761 AFY with the implementation of the Project. Due to the lack of surplus water supplies in the Project Area, this level of consumption, although relatively small in comparison with other uses, is a significant impact and contributes to a cumulatively significant impact to sustainable groundwater management. These impacts would be significant and unavoidable.

Mitigation Measures

Implement MM 4.9-1 through MM 4.9-6, as described above, and the groundwater mitigation measures described in Section 4.17, Utilities and Service Systems.

Level of Significance After Mitigation

Significant and unavoidable with mitigation.

Impact 4.9-3: Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or through the addition of impervious surfaces, in a manner which would: (i) result in a substantial erosion or siltation on- or offsite; (ii) substantially increase the rate of amount of surface runoff in a manner which would result in flooding on-or offsite; (iii) create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff; or (iv) impede or redirect flood flows.

The analysis of the potential of the Project to substantially alter the existing drainage pattern of the site which would result in substantial erosion or siltation on –or offsite was assessed in Chapter 4.9 of the 2015 FEIR (SREIR Volume 3). MM 4.9-1 through MM 4.9-6 from the 2015 FEIR continue to be required.

Mitigation Measures

Implement MM 4.9-1 through MM 4.9-6, as described above, and the groundwater mitigation measures described in Section 4.17, Utilities and Service Systems.

Level of Significance After Mitigation

Less than significant with mitigation.

Impact 4.9-4: Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or through the addition of impervious surfaces, in a manner which would: (i) result in a substantial erosion or siltation on- or offsite; (ii) substantially increase the rate of amount of surface runoff in a manner which would result in flooding on-or offsite; (iii) create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff; or (iv) impede or redirect flood flows.

The analysis of the potential of the Project to substantially alter the existing drainage pattern of the site which would substantially increase the rate of amount of surface runoff in a manner which would result in flooding on- or offsite was assessed in Chapter 4.9 of the 2015 FEIR (SREIR Volume 3). MM 4.9-1 to MM 4.9-6 from the 2015 FEIR continue to be required.

Mitigation Measures

Implement MM 4.9-1 through MM 4.9-6, as described above, and the groundwater mitigation measures described in Section 4.17, Utilities and Service Systems.

Level of Significance After Mitigation

Less than significant with mitigation.

Impact 4.9-5: Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or through the addition of impervious surfaces, in a manner which would: (i) result in a substantial erosion or siltation on- or offsite; (ii) substantially increase the rate of amount of surface runoff in a manner which would result in flooding on-or offsite; (iii) create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff; or (iv) impede or redirect flood flows.

The analysis of the potential of the Project to substantially alter the existing drainage pattern of the site which would create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff was assessed in Chapter 4.9 of the 2015 FEIR (SREIR Volume 3). MM 4.9-1 to MM 4.9-6 from the 2015 FEIR continue to be required.

Mitigation Measures

Implement MM 4.9-1 through MM 4.9-6, as described above.

Level of Significance After Mitigation

Less than significant with mitigation.

Impact 4.9-6: Violate any water quality standards or waste discharge requirements or otherwise substantially degrade surface or groundwater quality.

The analysis of the potential of the Project to otherwise substantially degrade surface or groundwater quality was assessed in Chapter 4.9 of the 2015 FEIR (SREIR Volume 3). MM 4.9-1 to MM 4.9-6 from the 2015 FEIR continue to be required.

Mitigation Measures

Implement MM 4.9-1 through MM 4.9-6, as described above, and the groundwater mitigation measures described in Section 4.17, Utilities and Service Systems.

Level of Significance After Mitigation

Less than significant with mitigation.

Impact 4.9-7: Place Housing within a 100-Year Flood Hazard Area as Mapped on a Federal Flood Hazard Boundary or Flood Insurance Rate Map or other Flood Hazard Delineation Map

The analysis of the potential of the Project to place housing within a 100-year flood hazard area as mapped on a federal flood hazard boundary or flood insurance rate map or other flood hazard delineation map was assessed in Chapter 4.9 of the 2015 FEIR (SREIR Volume 3)

Mitigation Measures

No mitigation measures are required since the Project does not include housing development.

Level of Significance

No impact.

Impact 4.9-8: Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or through the addition of impervious surfaces, in a manner which would: (i) result in a substantial erosion or siltation on- or offsite; (ii) substantially increase the rate of amount of surface runoff in a manner which would result in flooding on- or offsite; (iii) create or contribute runoff water which would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff; or (iv) impede or redirect flood flows.

The analysis of the potential of the Project to substantially alter the existing drainage pattern of the site and impede or redirect flood flows was assessed in Chapter 4.9 of the 2015 FEIR (SREIR Volume 3). MM 4.9-1 to MM 4.9-6 from the 2015 FEIR continue to be required.

Mitigation Measures

Implement MM 4.9-1 through MM 4.9-6, as described above.

Level of Significance After Mitigation

Less than significant with mitigation.

Impact 4.9-9: Expose People or Structures to a Significant Risk of Loss, Injury, or Death Involving Flooding, Including Flooding as a Result of the Failure of a Levee or Dam

The analysis of the potential of the Proposed Project to expose people or structures to a significant risk of loss, injury, or death involving flooding, including flooding as a result of the failure of a levee or dam was assessed in Chapter 4.9 of the 2015 FEIR (SREIR Volume 3). MM 4.9-1 to MM 4.9-6 from the 2015 FEIR continue to be required.

Mitigation Measures

Implement MM 4.9-1 through MM 4.9-6, as described above, and the groundwater mitigation measures described in Section 4.17, Utilities and Service Systems.

Level of Significance After Mitigation

Less than significant with mitigation.

Impact 4.9-10: In flood hazard, tsunami, seiche zones, risk release of pollutants due to project inundation

The analysis of the potential of the Project to risk release of pollutants due to project inundation in flood hazard, tsunami, or seiche zones, was assessed in Chapter 4.9 of the 2015 FEIR (SREIR Volume 3). None of the oil and gas exploration and production activities occurs or would occur in locations where seiche, tsunami, or mudflow inundation would occur. Therefore, there would be no impact.

Mitigation Measures

No mitigation measures are required.

Level of Significance

No impact.

4.9.5 Cumulative Setting, Impacts, and Mitigation Measures

Kern County has and is expected to continue to grow, with or without the Project, consistent with current growth projections included in the Kern Council of Government's Regional Transportation Plan/Sustainable Communities Strategy and accompanying EIR. This growth will be required to conform to all applicable federal, state, regional, and local agency laws and regulations that protect water quality, groundwater elevations and aquifer volumes (including the pending GSP development and implementation process), drainage patterns affecting siltation, erosion and flooding, the capacity of existing and planned stormwater drainage facilities, other water quality degradation, housing, people and structures in locations at risk of flood or dam-failure inundation, and other hydrological resources.

Impact 4.9-11: Contribute to Cumulative Hydrology and Water Quality Impacts

As described above, the ongoing production of oil and gas in Kern County, with the additional mitigation measures and other substantive and procedural requirements included in the proposed revisions to the County's oil and gas ordinances included in the Project, is not expected to result in significant impacts to hydrology and water other than to sustainable groundwater management or SGMA plan implementation. The implementation of MM 4.9-1 through MM 4.9-6 would reduce potential cumulative impacts to water quality, erosion risks, flooding, and other hydrologic resources to less than significant with mitigation. The Project would result in the increased oil and gas use of domestic and irrigation quality water from 8,778 AFY in 2012 to 11,761 AFY in 2035. As discussed in Impact 4.9-2, due to the lack of surplus water supplies in the Project Area, this level of consumption, although relatively small in comparison with other uses, is a significant impact and contributes to a cumulatively significant impact to sustainable groundwater management and SGMA plan implementation. It is possible that, consistent with the adopted GSPs and management area plans in the Project Area, additional produced water will be used to supplement supplies in the KCS and in other locations over time. While this outcome would support rather than impact sustainable groundwater management and SGMA plan implementation in the Project Area, SGMA Projects that would increase produced water reuse have yet to be implemented by the GSAs with statutory authority for ~~managing groundwater~~ *implementing SGMA* in the Project Area.

As discussed under Impact 4.9.2, it is not feasible to implement mitigation measures that directly curtail oil and gas activities to reduce water demand, or indirectly attempt to reduce or avoid Project impacts by curtailing demand from other activities, including agriculture. Although the GSPs and management area plans in the Project Area identify SGMA Projects that could be implemented to achieve SGMA goals over the next 20 years, it is virtually certain that these will *be modified through the adaptive management of the plans, in response to the multiple interests that Project Area GSAs are required to consider under the SGMA, as additional technical and monitoring information is developed, and as the GSAs with the statutory authority to implement the SGMA attempt to minimize detrimental impacts to the local economy, livelihood of residents and business owners, and the well-being of Metropolitan Bakersfield and Kern County.*

Water Code Section 10723.2 requires that duly formed GSAs consider the interests of all beneficial uses and users of groundwater in the development and implementation of GSPs and management area plans, including disadvantaged communities. There is substantial evidence that, due in part to a lack of resources, disadvantaged community interests in groundwater supplies have not been sufficiently considered in the development and implementation of GSPs and management area plans. A July 2020 report by researchers at the University of California, Davis found that most GSPs developed in the state do not adequately consider how drinking water stakeholders could be impacted based on applicable SGMA Sustainable Management Criteria and do not promote disadvantaged community benefits (Dobbin et al. 2020). Project M&I water use contributes towards a cumulatively significant impact on disadvantaged communities that are beneficial users of groundwater but not adequately considered in SGMA plans adopted in the Project Area.

MM 4.17-5 requires that oil and gas applicants subject to Oil and Gas Conformity Review pay a $250 mitigation fee per well and those subject to Minor Activity Reviews pay $50 per well. These funds will be deposited into a Disadvantaged Community Drinking Water Grant Fund to be implemented by Kern County Public Health in the form of grants available only for projects in disadvantaged communities in the Valley portion of Kern The use of the grant funding would be targeted for the design, permitting, and construction of physical improvements to water wells or water systems serving the disadvantaged community and primarily would act as matching funds for larger grant opportunities from other sources. Based on the average permitting activity, this mitigation will generate an estimated $460,000 annually. These funds will mitigate for the Project's fair share of cumulative impacts to disadvantaged communities that are insufficiently considered in the existing SGMA process.

As discussed in Impact 4.9-2, there is no other feasible mitigation for reducing the Project's potential impacts to groundwater. MM 4.17-3 and 4.17-4 will ensure that future activities permitted under the Project, including activities subject to Oil and Gas Conformity Reviews and Minor Activity Reviews, and permitted through the County's CUP process, will provide regional groundwater management agencies with sufficient information, including groundwater use from metered wells, to integrate Project-related groundwater use with the development of a comprehensive sustainable groundwater management solution for basins and subbasin in the Project Area. Accordingly, oil and gas demand for domestic and irrigation quality water is projected to increase from 8,778 AFY to 11,761 AFY with the implementation of the Project, a level of water use that will contribute to a cumulatively significant impact to sustainable groundwater management and SGMA plan implementation. ~~*As discussed in Impact 4.9-2, there are no feasible mitigation measures that will reduce these significant impacts to a predictable extent.*~~ As a result, cumulative impacts to sustainable groundwater management and SGMA plan implementation will remain significant and unavoidable.

Mitigation Measures

Implement MM 4.9-1 through MM 4.9-6, as described above, and MM 4.17-3, 4.17-4, and 4.17-5 as described in Section 4.17, Utilities and Service Systems.

Level of Significance After Mitigation

Significant and Unavoidable ~~with mitigation;~~ *for cumulative impacts.*

Base Map Source: Belitz, K., Dubrovsky, N.M., Burow, K., Jergens, B., and T. Johnson, 2003.

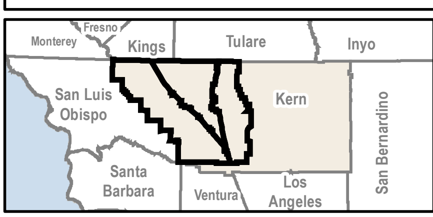


Figure 4.9-1
Kern County Subbasin with Respect to the Hydrogeologic Provinces of California Kern County, California

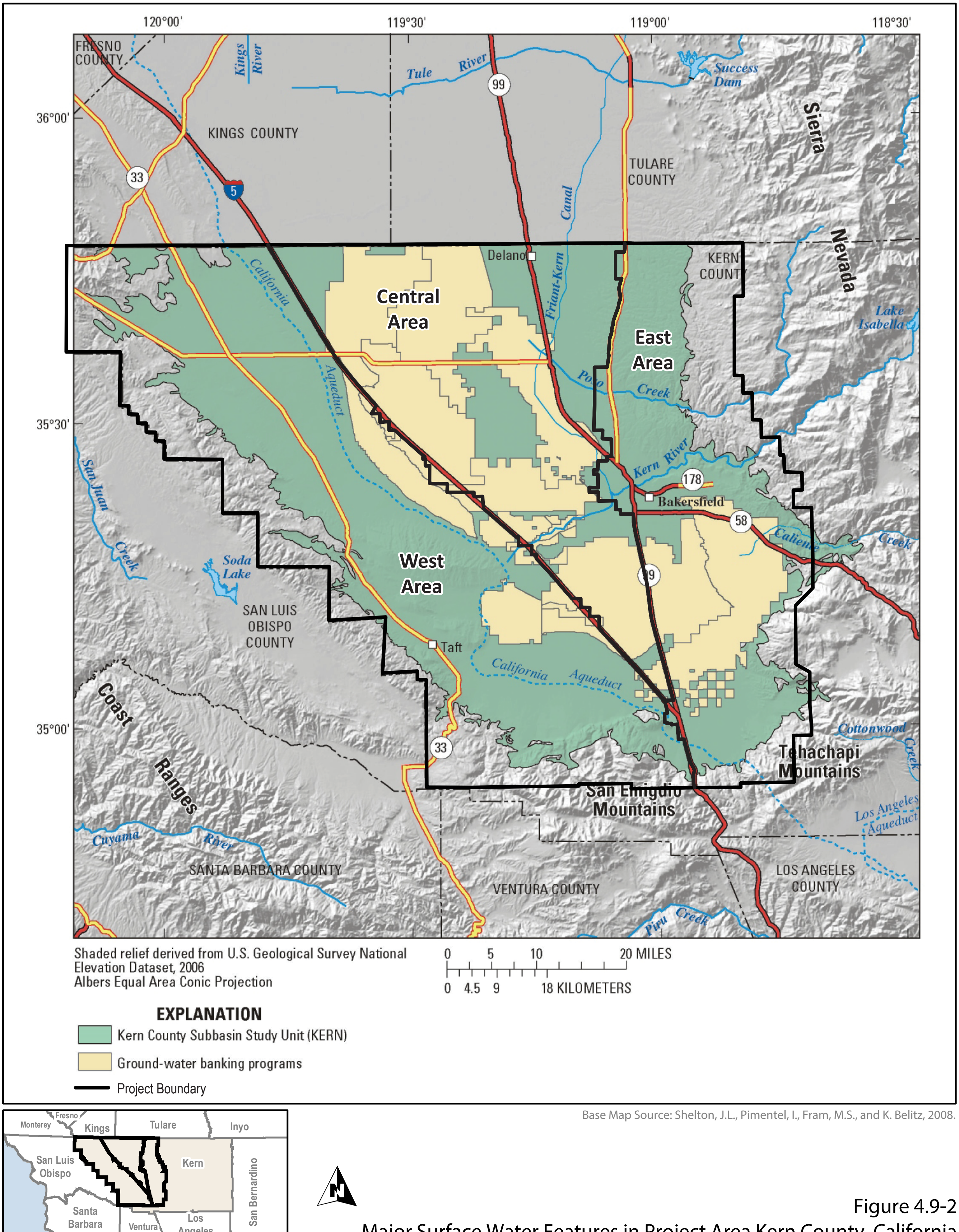


Figure 4.9-2
Major Surface Water Features in Project Area Kern County, California

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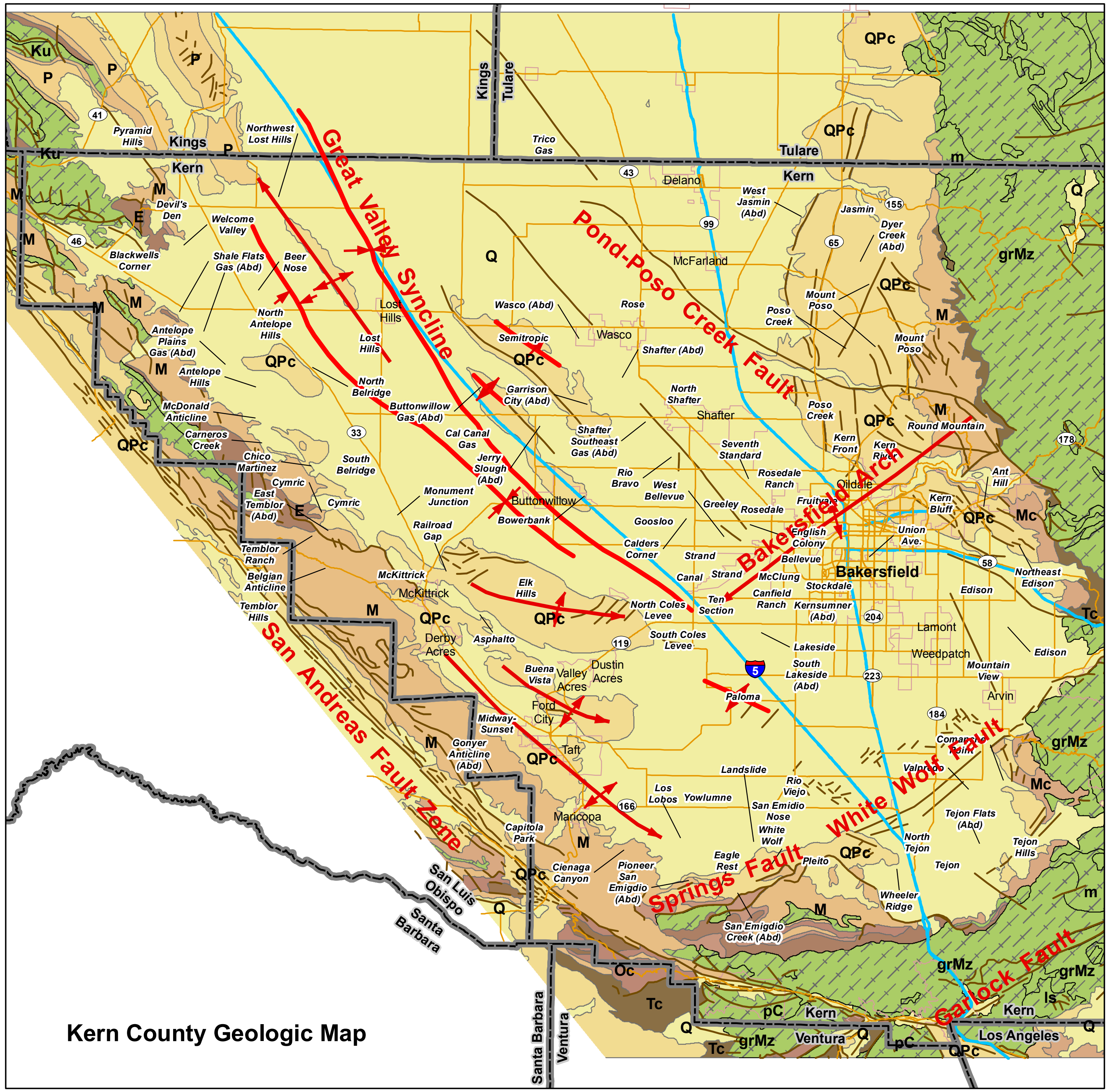
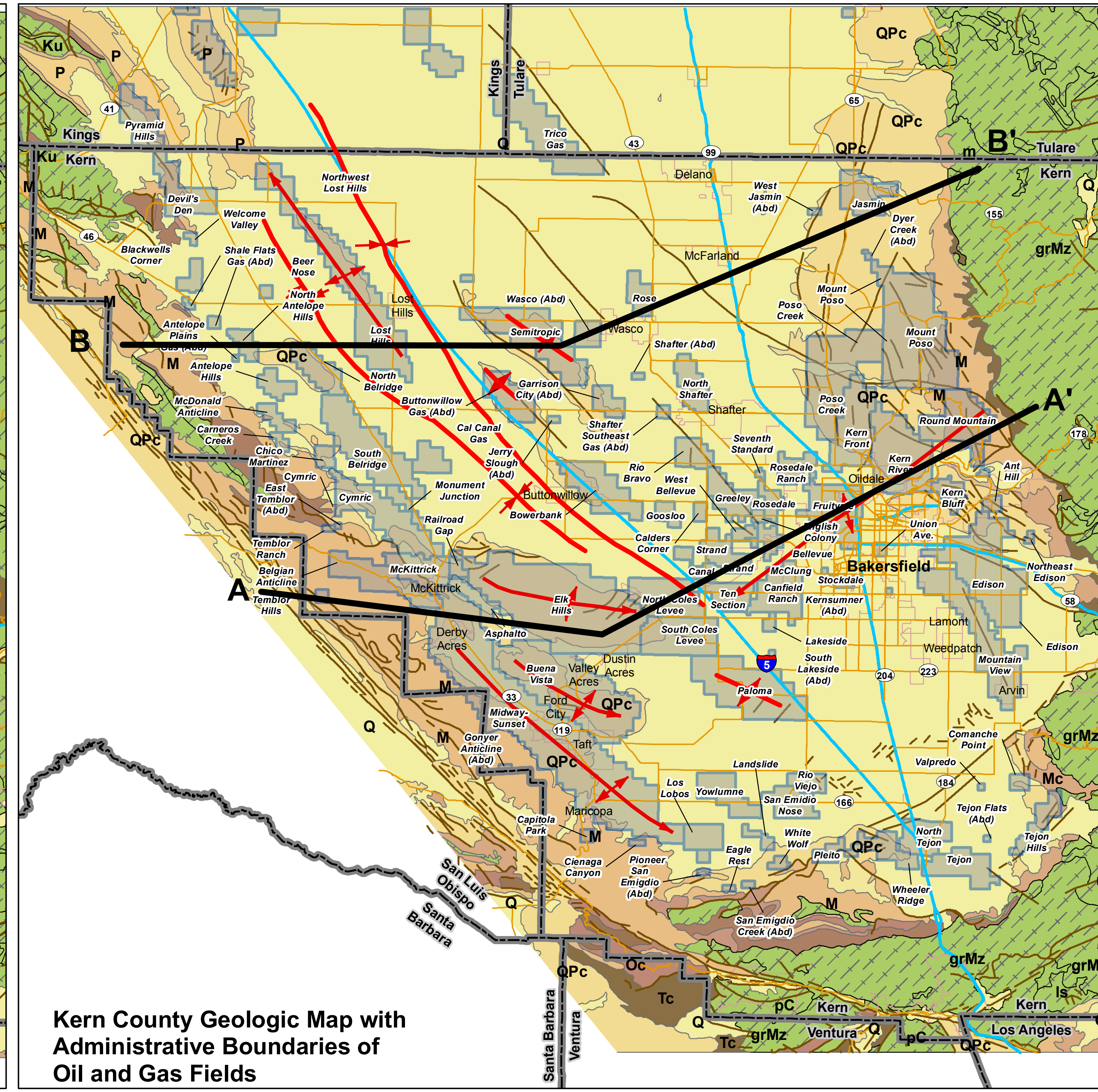
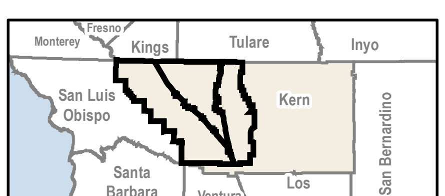
V:\Projects\KernOilGasEIR\Events\20140306_GeologyFigures\Figure 2-01_GeologicMap.mxd





Source: Jennings, C.W. and Gutierrez, C.I. 2010. Geologic Map of California. California Geological Survey, Sacramento, CA. Geologic Data Map 2 2010.; Ludington, S., Moring, B.C., Miller, R.J., Stone, P.A., Bookstrom, A.A., Bedford, D.R., Evans, J.G., Haxel, G.A., Nutt, C.J., Flyn, K.S., and Hopkins, M.J. 2007. Preliminary Integrated Geologic Map Databases for the United States, Western States: California, Nevada, Arizona, Washington, Oregon, Idaho, and Utah, Version 1.3. U.S. Geological Survey, Reston, VA. USGS Open-File Report 2005-1305.; DOGGR. 2005. Data Set: Oil and Gas Fields. California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, Sacramento, CA. [ftp://ftp.consrv.ca.gov/pub/oil/Data_Catalog/Oil_and_Gas/Oil_fields/, retrieved 1 May 2014]; ESRI 2010 Street Map.



N

0 5 10
Scale: Miles

Legend

- Anticline
- Syncline
- Fault
- Project Boundary
- County Boundary
- Town
- Interstate Highway
- State Highway
- Oil Field Administrative Boundary

Geology

- Qp Alluvium
- Qls Landslide deposits
- QPc Plio-Pleistocene non-marine
- P Pliocene marine
- M Miocene marine
- Mc Miocene non-marine
- O Oligocene marine
- Oc Oligocene non-marine
- E Eocene marine
- Ep Paleocene marine
- Tc Tertiary non-marine (undivided)
- Metamorphic and igneous rocks

Figure 4.9-3
Geologic Map with Kern County Oil and Gas Fields

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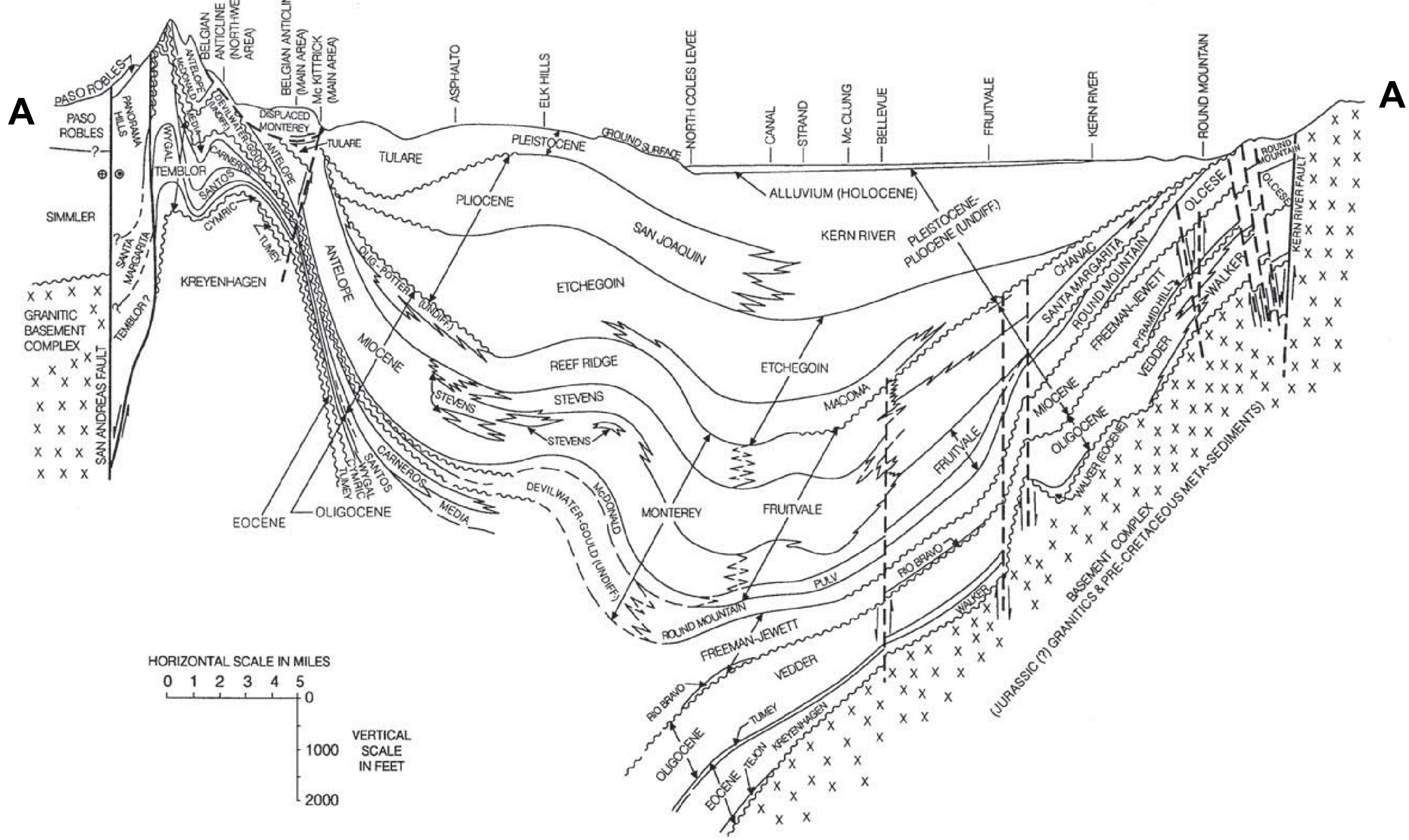
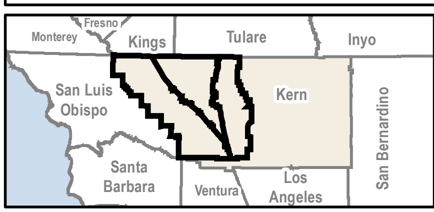
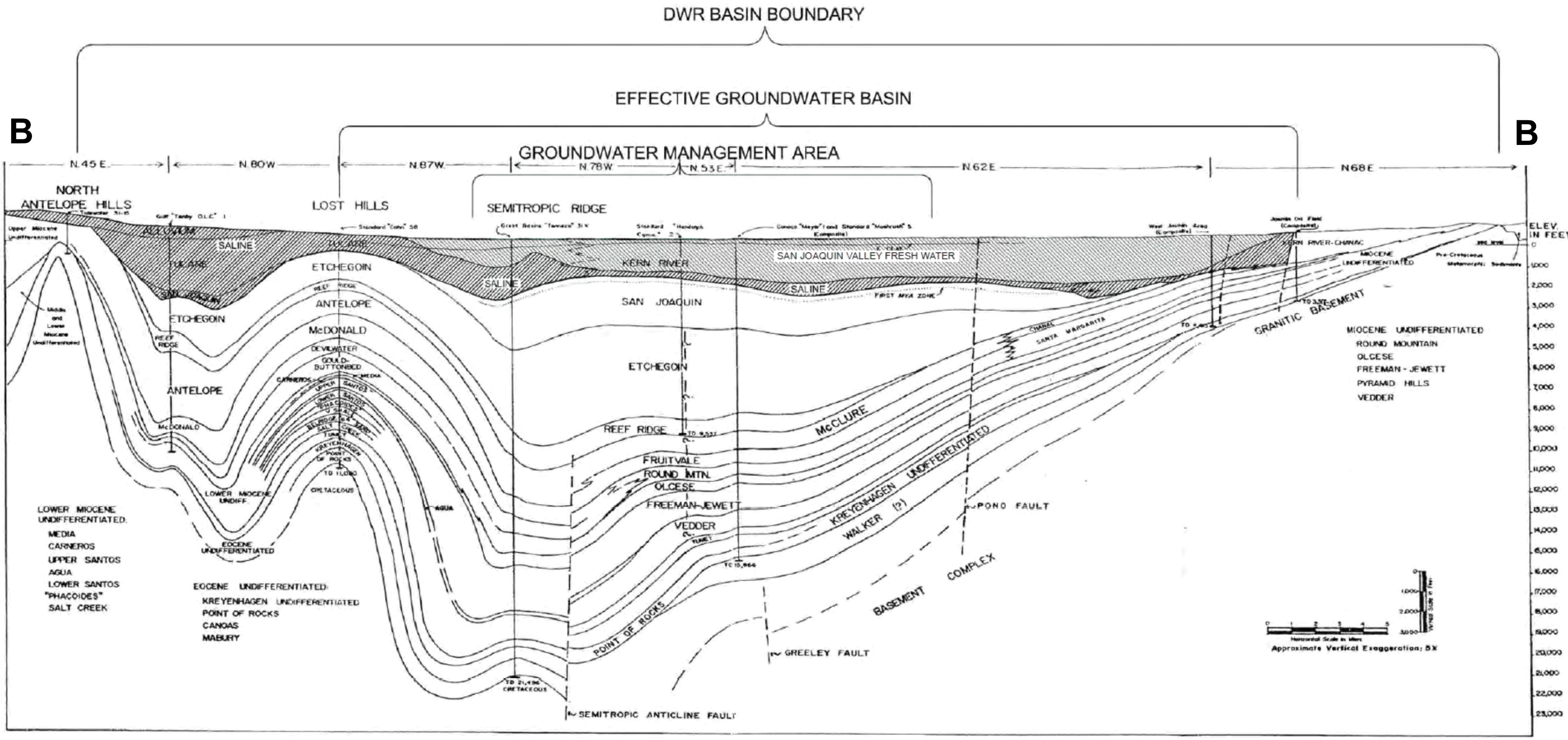
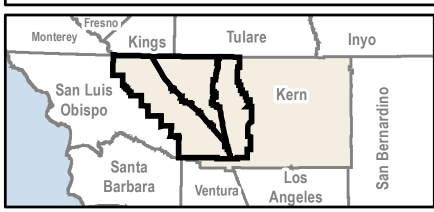




Source: DOGGR. 1998. California Oil & Gas Fields, volume 1 - Central California, contour maps, cross sections, and data sheets for California's oil and gas fields. California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, Sacramento, CA.

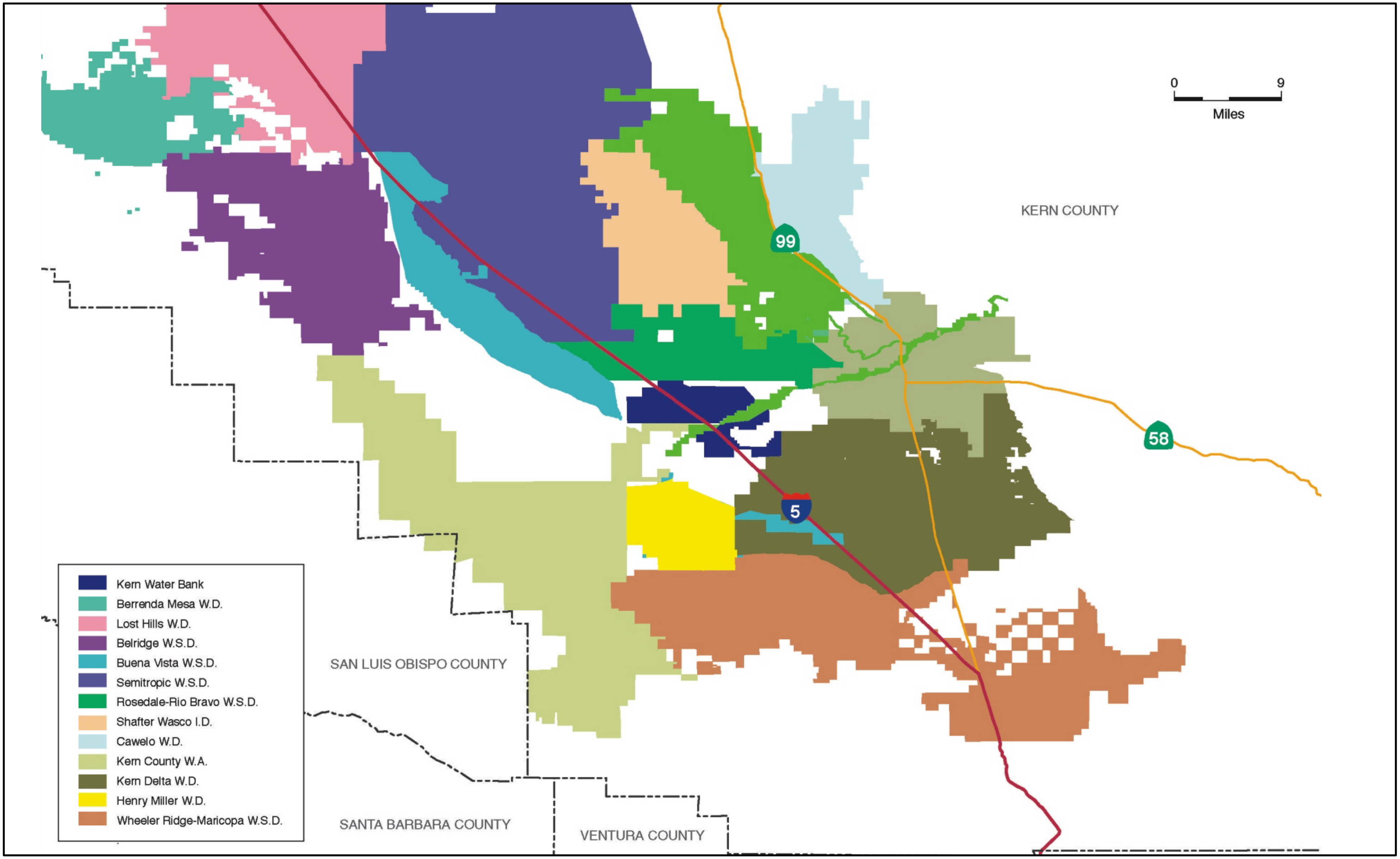
Figure 4.9-4
Generalized Geologic Cross Section across Southern San Joaquin Valley





Source: SWSD. 2012. 2012 Groundwater Management Plan, Kern County, California. Semitropic Water Storage District., adapted from an original figure in Karp (1968).

Figure 4.9-5
Generalized Geologic Cross Section Showing Relation of Groundwater Aquifer



Base Map Source: CASIL, 2007; ESA, 2007.

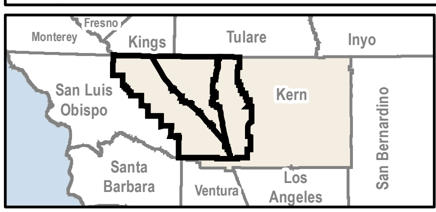
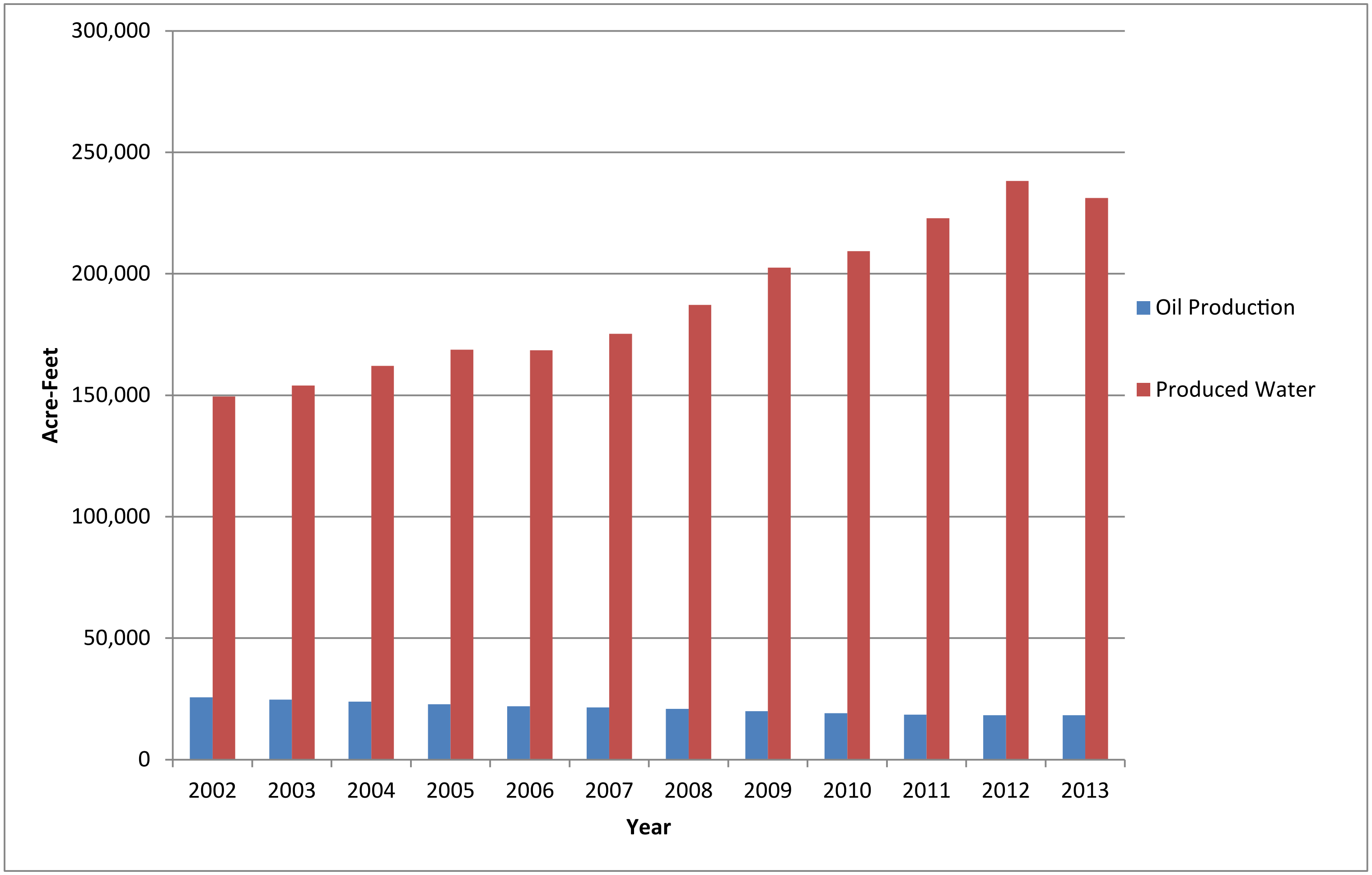


Figure 4.9-6
Location of Kern County, California Water Banking Programs Kern County, California



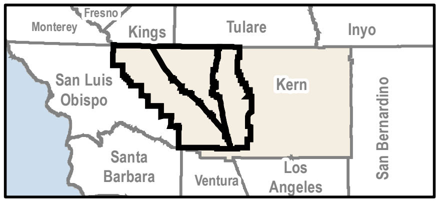


Figure 4.9-7
Project Area Oil and Produced Water Production
2002-2013 (acre-feet)

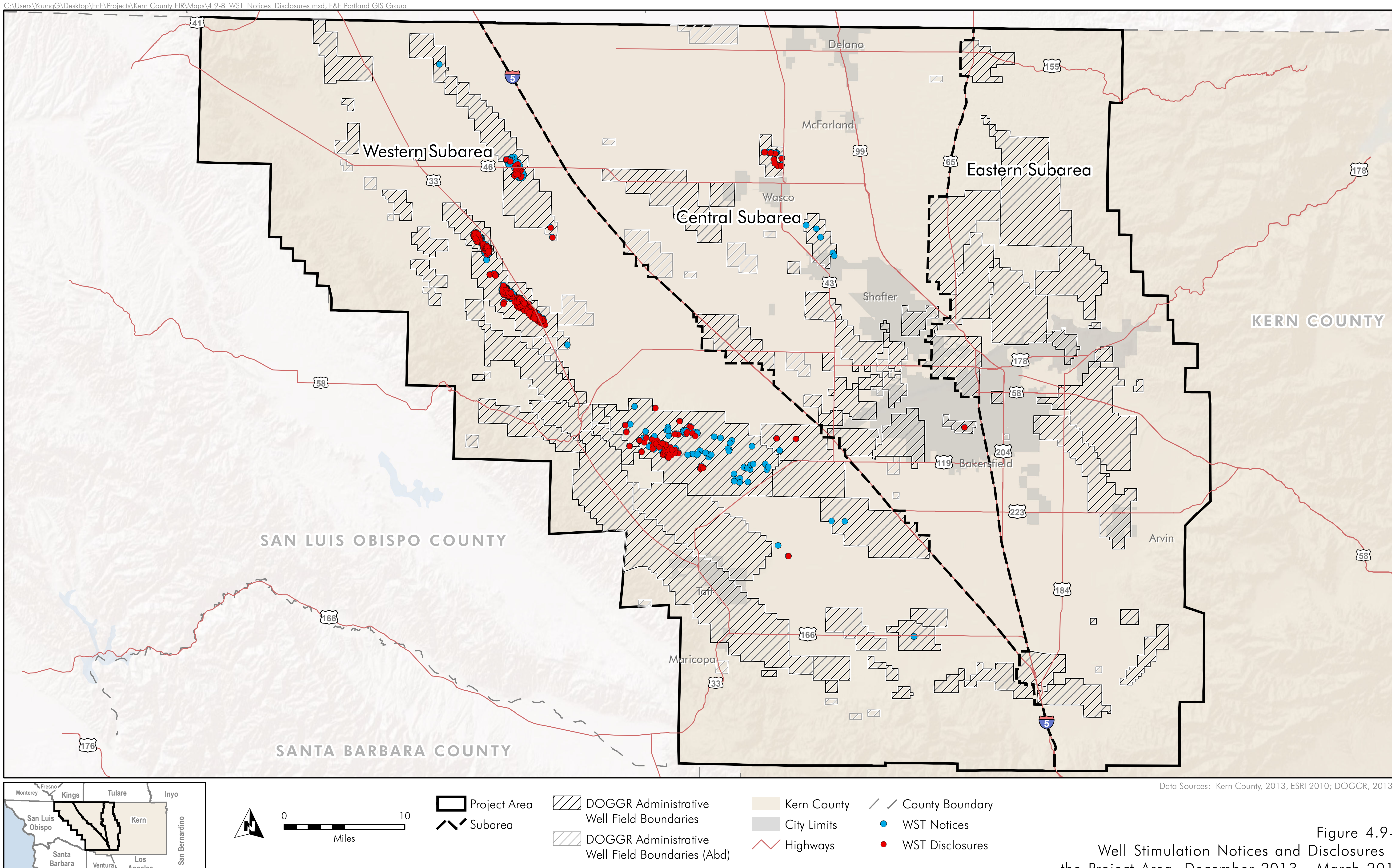


Figure 4.9-8
Well Stimulation Notices and Disclosures in the Project Area, December 2013 - March 2015

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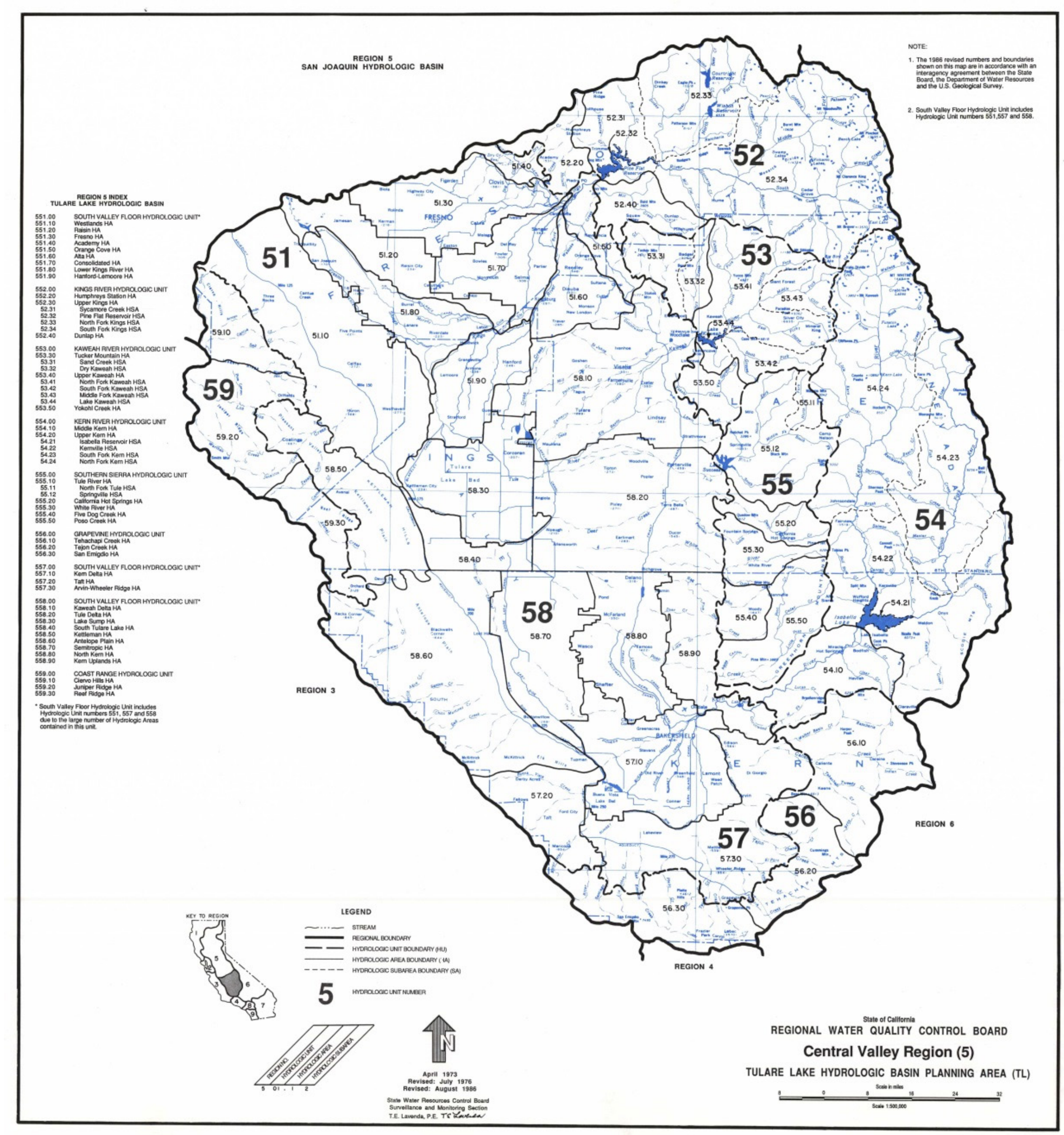
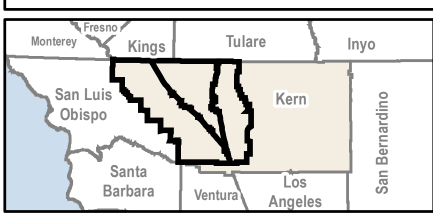
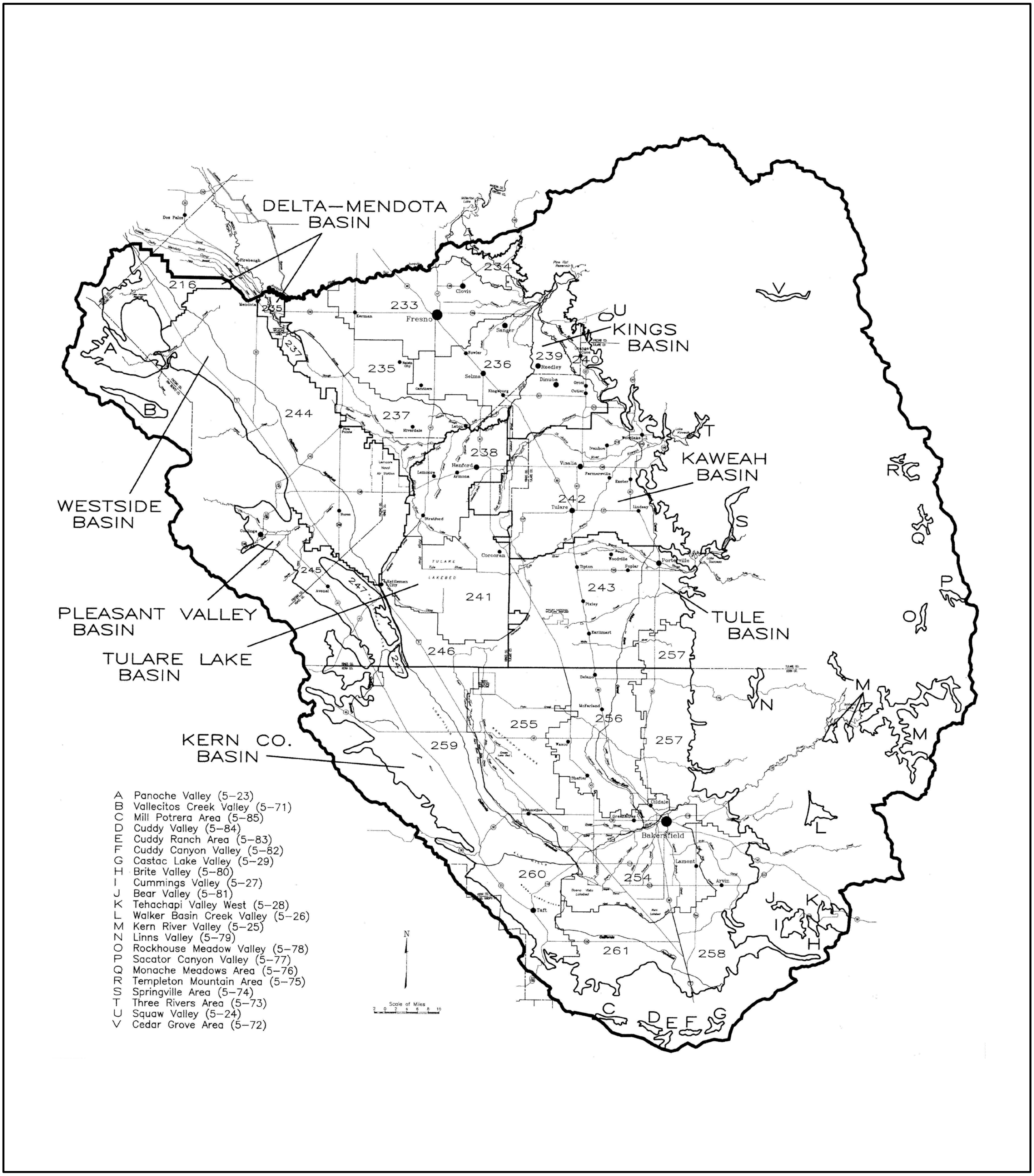
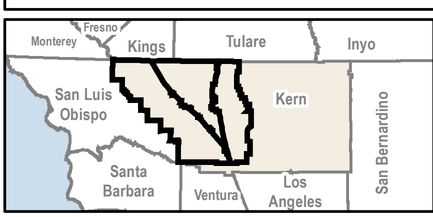




Source: Water Quality Control Plan for the Tulare Lake Basin (CRWQCB 2004) available at http://www.waterboards.ca.gov/centralvalley/water_issues/basin_plans/tlb_figll_1.pdf

Figure 4.9-9
Hydrologic Basins and Surface Waterbodies, San Joaquin Hydrologic Basin

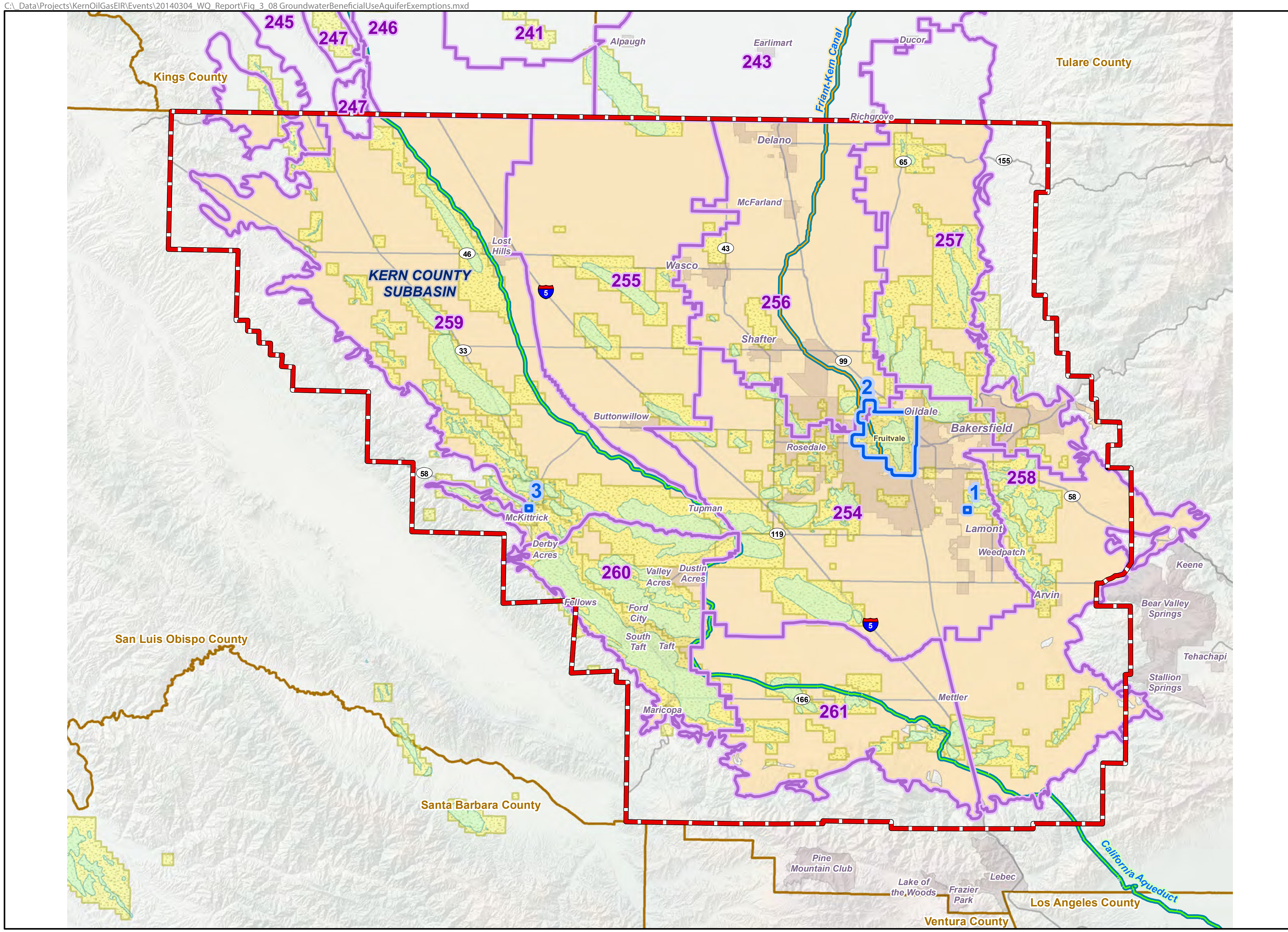




Source: Water Quality Control Plan for the Tulare Lake Basin (CRWQCB 2004) available at http://www.waterboards.ca.gov/centralvalley/water_issues/basin_plans/tlb_figll_2.pdf

Figure 4.9-10
Detailed Analysis Units, San Joaquin Hydrologic Basin

C:_Data\Projects\KernOilGasEIR\Events\20140304_WQ_Report\Fig_3_08 GroundwaterBeneficialUseAquiferExemptions.mxd

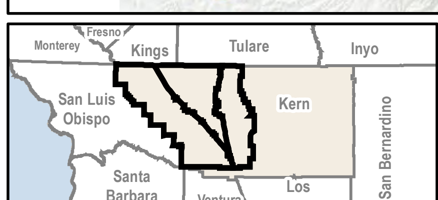


Notes:
Groundwater Beneficial Use Exemptions as defined in the Water Quality Control Plan (Basin Plan) for the Tulare Lake Basin (CA RWQCB. 2004. Water Quality Control Plan for the Tulare Lake Basin, Second Edition. California Regional Water Quality Control Board, Central Valley Region (Region 5). [Available at: http://www.waterboards.ca.gov/centralvalley/water_issues/basin_plans/index.shtml, retrieved 18 February 2014]), Table II-2:

1) Groundwater contained in the lower Transition Zone and Santa Margarita formation within 3,000 feet of the Kern Oil and Refining Company proposed injection wells in Section 25, T30S, R28E, MDB&M, is not suitable, or potentially suitable, for municipal or domestic supply (MUN).

2) Ground water contained in the basal Etchegoin formation, Chanac formation, and Santa Margarita formation within, and extending to one-quarter mile outside the administrative boundary of the Fruitvale Oil Field, as defined by the State of California, Department of Conservation, Division of Oil and Gas in Application for Primacy in the Regulation of Class II Injection Wells Under Section 1425 of the Safe Drinking Water Act, dated April 1981, is not suitable, or potentially suitable, for municipal or domestic supply (MUN). However, the upper ground water zone (ground water to a depth of 3,000 feet) retains the MUN beneficial use.

3) Ground water and spring water within 1/2 mile radius of the McKittrick Waste Treatment (formerly Liquid Waste Management) site in Section 29, T30S, R22E, MDB&M, have no beneficial uses.



0 4 8
Miles

- Exempted Aquifers
- Groundwater Beneficial Use Exemptions (see notes)
- California Aqueduct
- Friant Kern Canal
- 254 Groundwater Detailed Analysis Unit
- Kern County Sub-basin
- Oil And Gas Field Boundaries
- Project Boundary
- County Boundaries

Figure 4.9-11
Approved Groundwater Beneficial Use Aquifer Exemptions

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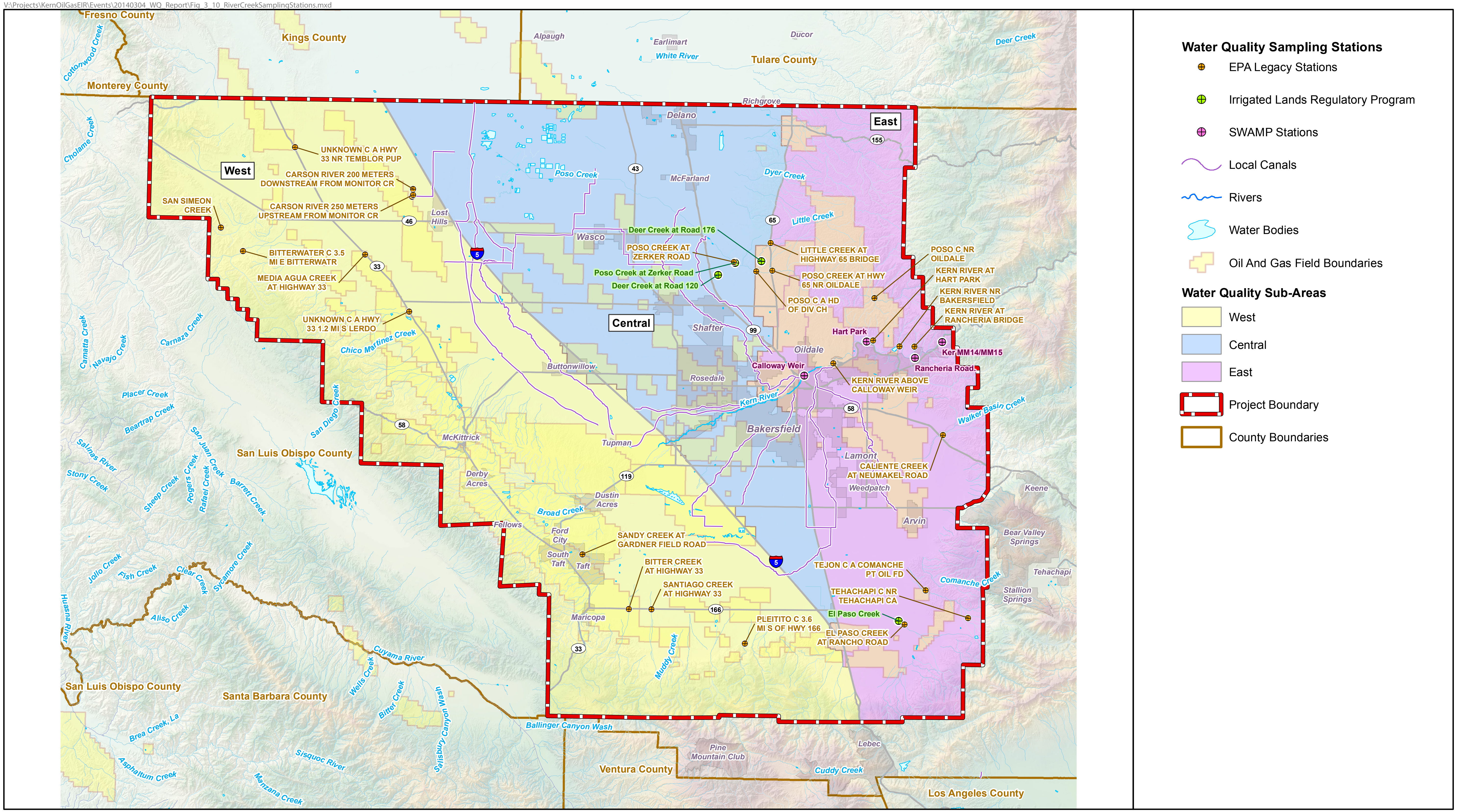

Figure 4.9-12
River, Creek and Stream Sampling Locations Used to Analyze Project and Subarea Surface Water Quality

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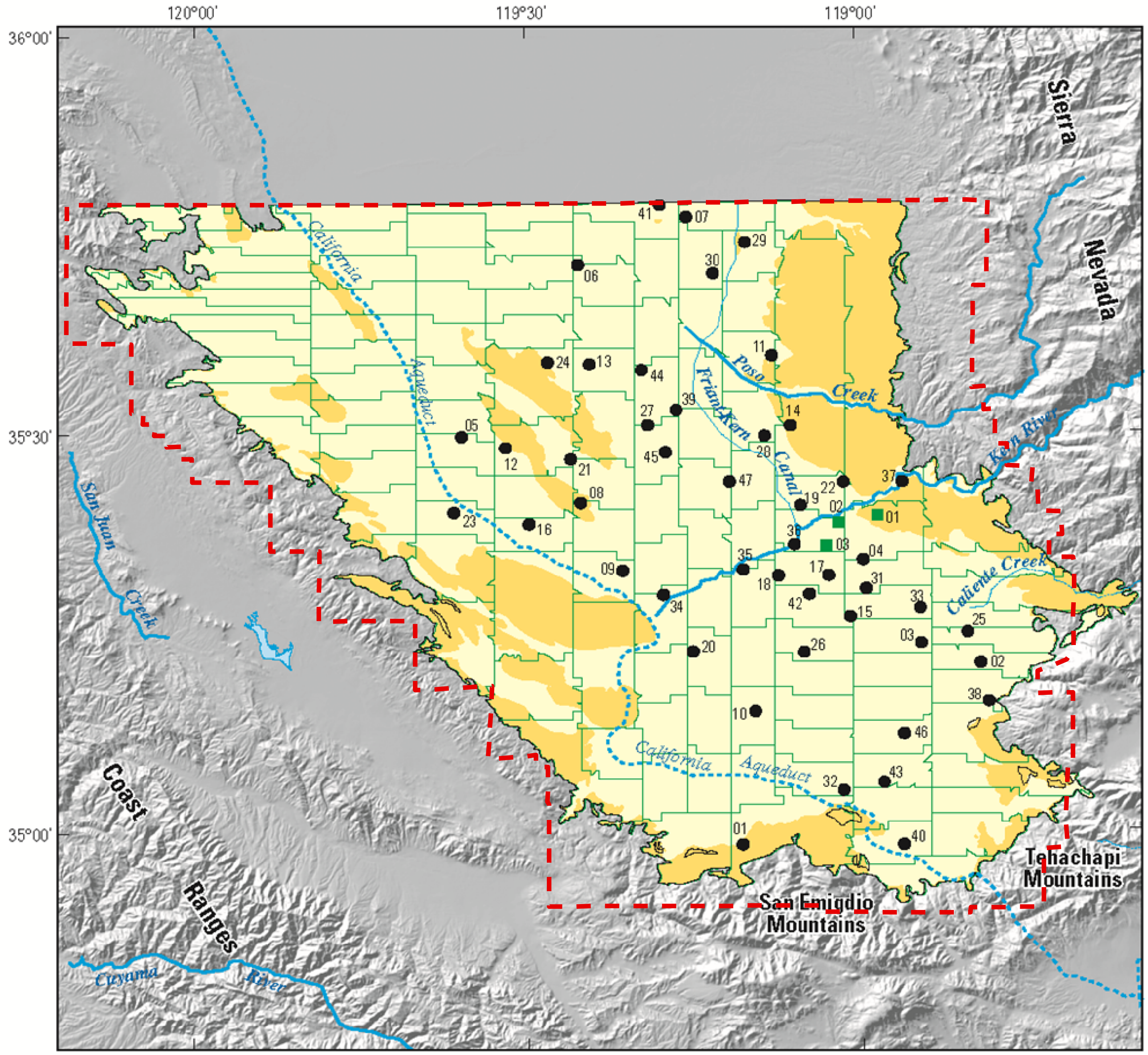

Shaded relief derived from U.S. Geological Survey National Elevation Dataset, 2006
Albers Equal Area Conic Projection

0 5 10 20 MILES
0 5 10 20 KILOMETERS

Surficial geology modified from Saucedo and others, 2000

EXPLANATION

Grid cell

Surficial geology

Quaternary alluvium

Plio-Pleistocene and older

Sampled wells—Alphanumeric identification numbers for grid wells have the prefix "KERN," and numbers for flow-path wells have the prefix "KERNFP" as defined in the text; only the numeric portions are shown on the map

01 Grid well

03 Flow-path well

Project Boundary

Notes:
10 Figure shows the grid and well locations used in the U.S. Geological Survey's summary of the California Groundwater Ambient Monitoring and Assessment (GAMA) database through 2006, and is reproduced from Shelton, J.S., Pimentel, I., Fram, M.S., and Belitz, K. 2008. Ground-Water Quality Data in the Kern County Subbasin Study Unit, 2006—Results from the California GAMA Program. U.S. Geological Survey, Reston, VA. USGS Data Series 337.
2) Project boundary is approximate and was superimposed on source figure.

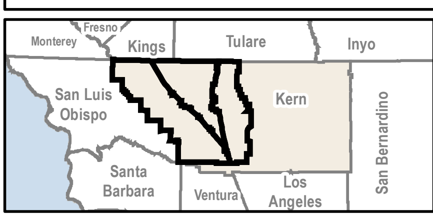

Figure 4.9-13
USGS Grid Well Locations Map

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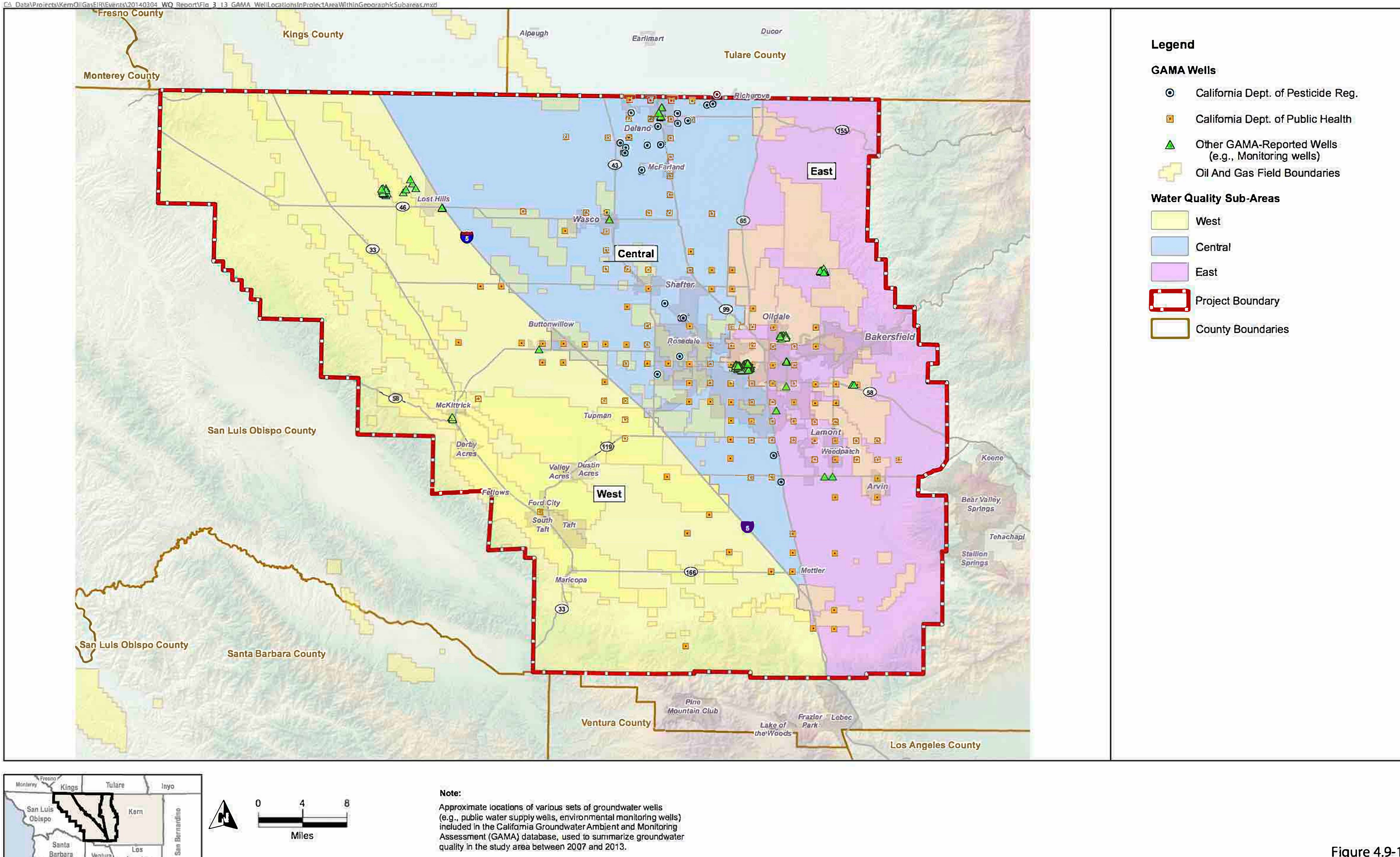

Note:
Approximate locations of various sets of groundwater wells (e.g., public water supply wells, environmental monitoring wells) included in the California Groundwater Ambient and Monitoring Assessment (GAMA) database, used to summarize groundwater quality in the study area between 2007 and 2013.

Figure 4.9-14
GAMA Well Locations in Project Area

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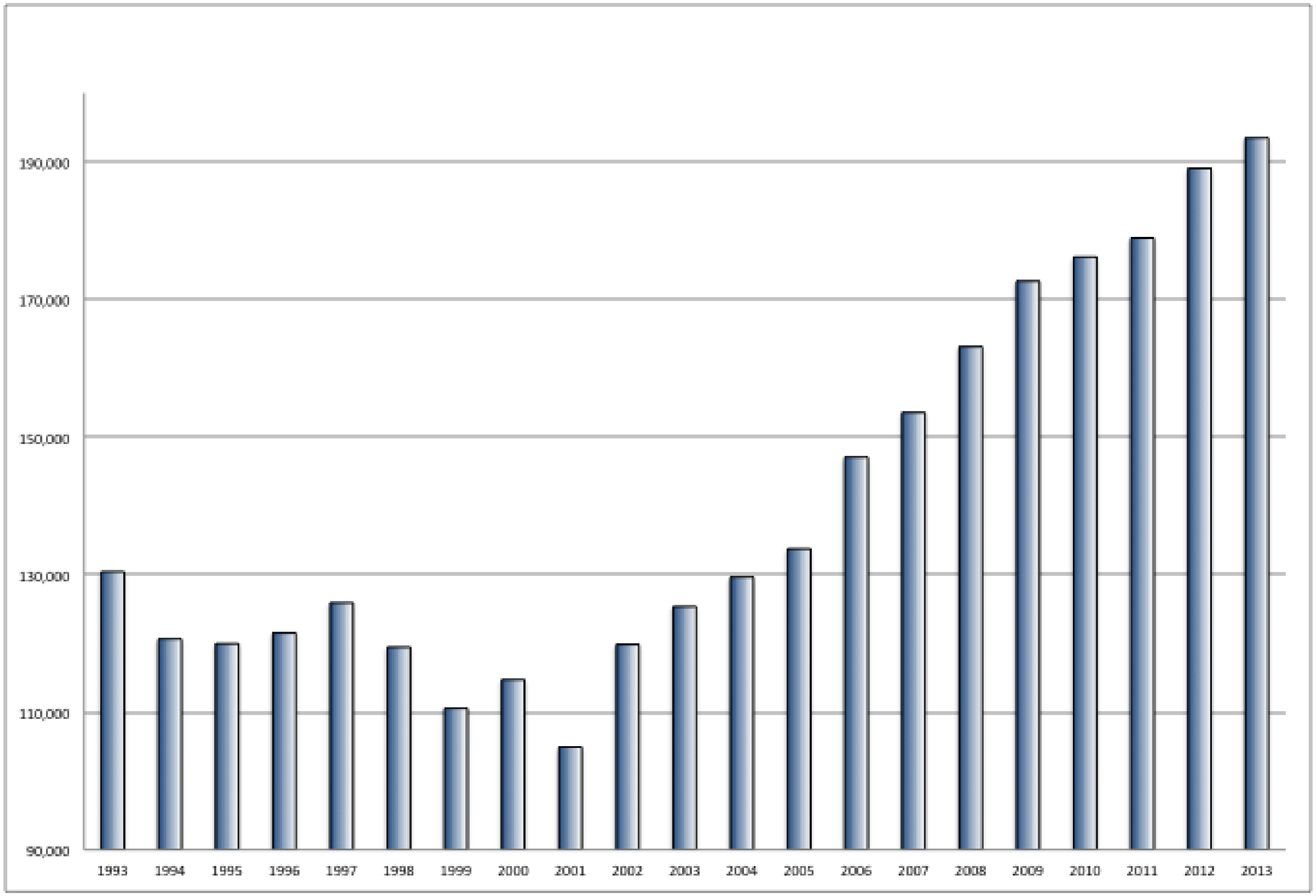
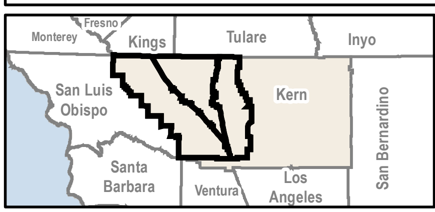
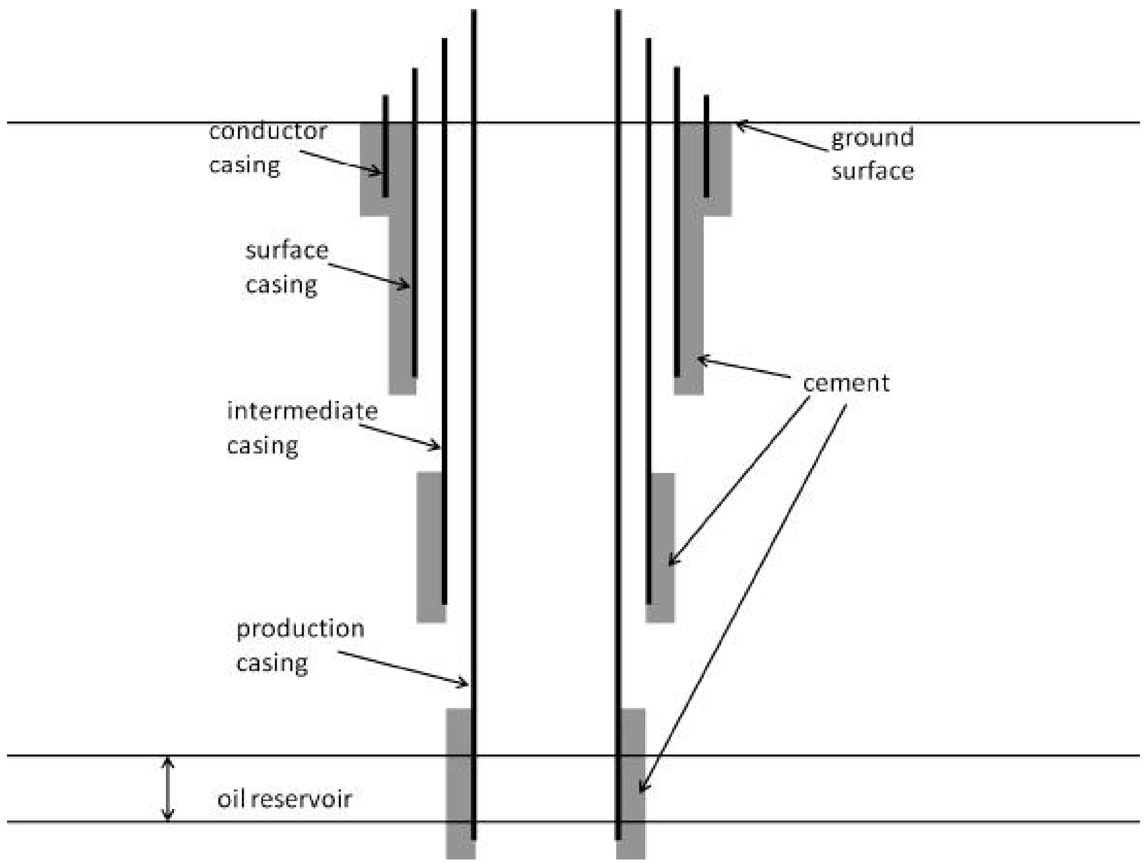




Source: DOGGR Spreadsheet (10 Fluid) Results - Best Numbers - Annual and Monthly reports.xlsx
(Note: data is for all District 4 fields and includes a small amount of production activity outside of the Project Area)

Figure 4.9-15
Total Project Area Injection Volume, Acre-Feet 1993-2013



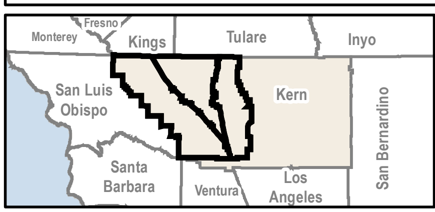


Figure 4.9-16
Schematic cross section of well casing and cement configuration. Casing extends above ground surface for connection to wellhead. (Redrawn and modified from API, 2009)

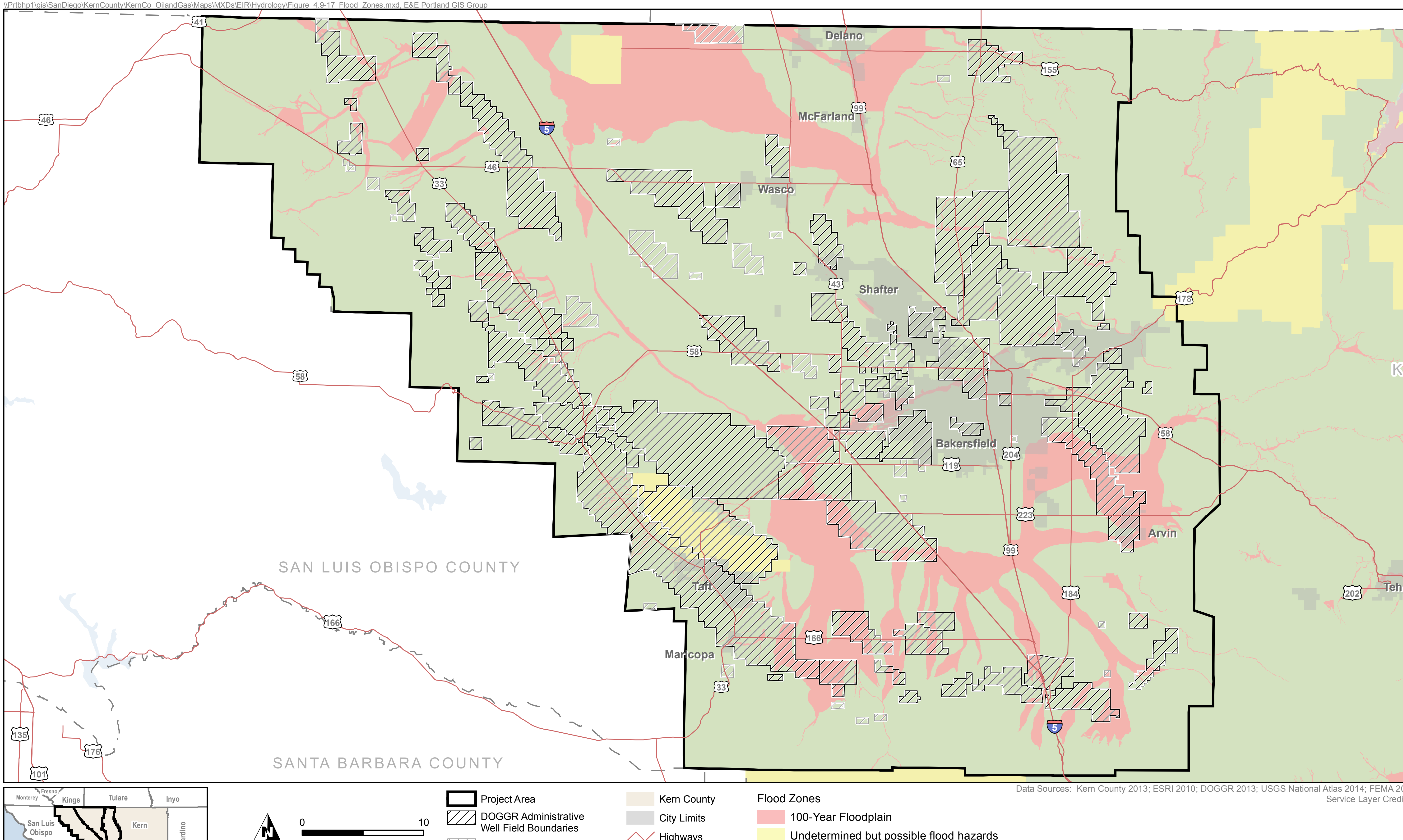


Figure 4.9-17
Flood Zones in the Project Area

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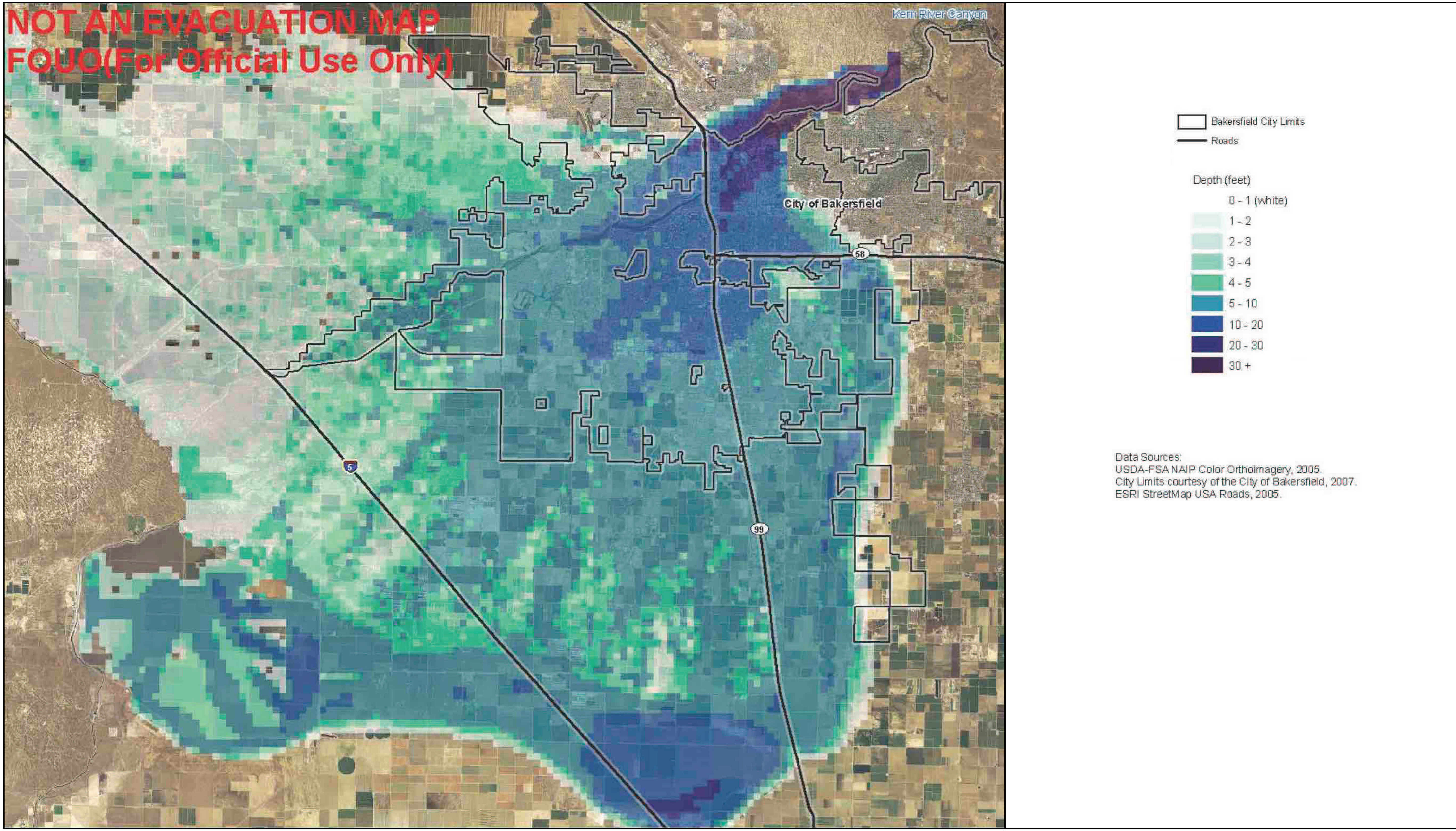

Source: Northwest Hydraulic Consultants, January 2008.

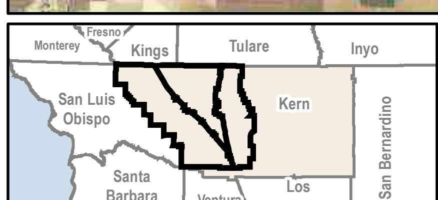

Figure 4.9-18
Potential Peak Elevation Inundation Depths

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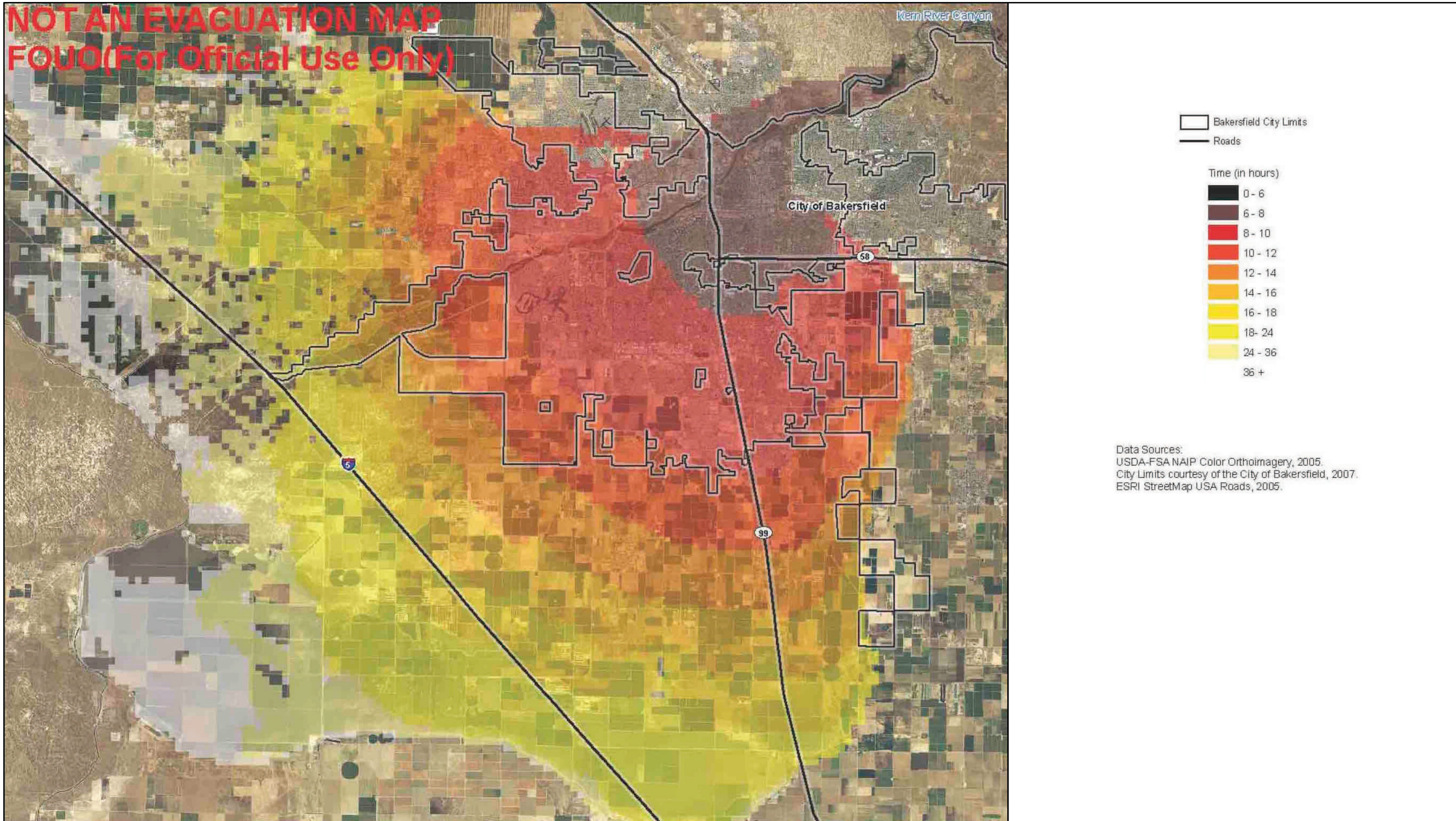

Source: Northwest Hydraulic Consultants, January 2008.

Figure 4.9-19
Hours to One-Foot Inundation From Failure of Lake Isabella Dam to Full Capacity

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Section 4.12

Noise

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Section 4.12
Noise

4.12.1 Introduction: Purpose/Scope

This section of the Supplemental Recirculated Environmental Impact Report (SREIR) describes the affected environment and regulatory setting for noise quality. This section is based on an independent evaluation of noise conditions in the Project Area, Project activities that cause noise, and the effectiveness of noise-related mitigation and avoidance measures. The section is also informed by the Environmental Noise Assessment Noise Study Technical Report prepared by Brown-Buntin Associates, Inc. (Brown-Buntin 2015), entitled "Environmental Noise Assessment, Oil and Gas Development EIR Kern County, California," which is presented in Appendix V-1 of the 2015 FEIR (SREIR Volume 5); the Vibration Assessment Report prepared by California Resources Corporation, entitled "Geophysical Surveys and Vibration," which is presented in Appendix V-2 of the 2015 FEIR (SREIR Volume 5); and the Gas Flare Noise Assessment prepared by WJV Acoustics, Inc., entitled "Acoustical Analysis: Gas Flare Noise Assessment, Oil and Gas Development EIR Kern County, California," which is presented in Appendix V-3 of the 2015 FEIR (SREIR Volume 7).

This section also describes the noise impacts that would result from implementation of the Amendment to Chapter 19.98 (Oil and Gas Production) and related ordinance amendments to the Kern County Zoning Ordinance, and future development of oil and gas resources pursuant to the Amended Ordinance (Project), and mitigation measures that would reduce these impacts, if necessary. <u>*Except where specifically noted, all underlined and italicized text indicates additions, and italicized strikethrough text indicates deletions from the SREIR (August 2020). Non-italicized underlined and strikethrough text is the same as in the SREIR (August 2020).*</u>

Terminology

Noise

The assessment of noise impacts uses specific terminology and fundamental descriptors not commonly used in everyday conversation. Therefore, to assist in a thorough understanding of the subsequent analysis, these terms are discussed in this subsection.

Acoustics is the study of sound, and noise is defined as unwanted sound.

Noise is a complex sound produced by various vibrations, often diffused and not harmonic. A noise is usually disturbing and unpleasant, whether the amplitude is high or low (i.e., noise from mechanical system, impact noise, loud music, etc.).

Airborne sound is a rapid fluctuation or oscillation of air pressure above and below atmospheric pressure creating a sound wave.

Ambient Noise is the composite of noise from all sources near and far. In this context, the ambient noise level constitutes the normal or existing level of environmental noise at a given location.

The **pitch** or loudness of sound determines whether a sound is of a pleasant or objectionable nature. Pitch, which is the height or depth of a tone or sound, is louder to humans when it is high-pitched versus low-pitched. The loudness of a sound is determined by a combination of the intensity of the sound waves with the reception characteristics of the ear.

Measurement scales are used to describe sounds. A **decibel (dB)** is a unit used to describe the amplitude of sound, and sound levels are calculated on a logarithmic, not linear, basis. The lowest sound level that an unimpaired human ear can hear is described as zero on the decibel scale. Due to the logarithmic nature of measuring sound levels on the decibel scale, a 10-dB increase represents a tenfold increase in acoustic energy, whereas a 20 dB increase represents a hundredfold increase in acoustic energy. Because a relationship exists between acoustic energy and intensity, each 10-dB increase in sound level can have an approximate doubling effect on loudness as perceived by the human ear.

The most common metric is the overall **A-weighted sound level measurement** (**dBA**) that has been adopted by regulatory bodies worldwide. The A-weighting network measures sound in a fashion similar to the way a person perceives or hears sound, thus achieving very good correlation in terms of evaluating acceptable and unacceptable sound levels.

The relative A-weighted noise levels of common sounds measured in the environment and industry for various qualitative sound levels are provided in Table 4.12-1.

Table 4.12-1: Typical Sound Levels Measured in the Environment and Industry

Noise Source at a Given Distance	A-Weighted Sound Level (in decibels)	Qualitative Description
Carrier deck jet operation Jet takeoff (200 feet)	140 130 120	Pain threshold
Auto horn (3 feet) Jet takeoff (1,000 feet) Shout (0.5 feet)	110 100	Maximum vocal effort
Heavy truck (50 feet)	90	Very annoying; hearing damage (8-hr, continuous exposure)
Pneumatic drill (50 feet) Freight train (50 feet) Freeway traffic (50 feet)	80 70 to 80 70	Annoying Intrusive (telephone use difficult)
Air conditioning unit (20 feet) Light auto traffic (50 feet) Living room/Bedroom	60 50 40	Quiet

Table 4.12-1: Typical Sound Levels Measured in the Environment and Industry

Noise Source at a Given Distance	A-Weighted Sound Level (in decibels)	Qualitative Description
Library/Soft whisper (5 feet) Broadcasting/Recording studio	30 20 10	Very quiet Just audible

Source: Adapted from Table E (NYSDEC 2001).

A-weighted sound levels can be measured or presented as **equivalent sound pressure level (L_{eq})**. This is defined as the average noise level, on an equal-energy basis for a stated period of time, and is commonly used to measure steady-state sound or noise that is usually dominant. Statistical measurements are typically denoted by L_n, where "n" represents the percentile of time the sound level is exceeded. The measurement of L_{90} represents the noise level that is exceeded during 90% of the measurement period. Similarly, the L_{10} represents the noise level exceeded for 10% of the measurement period. The maximum noise level (L_{max}) is the maximum instantaneous noise level during a specific period of time.

Of particular interest in this analysis are other descriptors of noise that are commonly used to help determine noise/land use compatibility and predict an average community reaction to adverse effects of environmental noise, including traffic-generated, construction, and industrial noise. One of the most universal descriptors is the average day-night level (DNL or L_{dn}). As a result of recommendation by the California Health Department and state planning law, this descriptor is used by many planning agencies, including Kern County's Planning and Community Development Department. The L_{dn} noise metric represents a 24-hour period and applies a time-weighted factor designed to penalize noise events that occur during nighttime hours when relaxation and sleep disturbance are of more concern for average residents. Noise occurring during the daytime hours—between 7:00 a.m. and 10:00 p.m.—is measured in decibels. Noise occurring between 10:00 p.m. and 7:00 a.m., however, is effectively "penalized" by adding 10 dB to the measured level. In California, the use of the community noise equivalent level (CNEL) descriptor is also permitted. CNEL is identical to the day-night average sound level metric, except that CNEL adds a 5 dB penalty for noise occurring during evening hours between 7:00 p.m. and 10:00 p.m. (Harris 1991) as well as the 10 dB penalty added between 10:00 p.m. and 7:00 a.m.

The decibel system of measuring sound gives a rough connection between the physical intensity of sound and its perceived loudness to the human ear. Ambient sounds generally range from 30 dB (very quiet) to 100 dB (very loud). As shown in Table 4.12-AA, changes of 1 to 3 dB are detectable under quiet, controlled conditions, and changes of less than 1 dB are usually not discernible (even under ideal conditions). A 3 dB change in noise levels is considered the minimum change that is detectable with human hearing in outside environments. A change of 5 dB is readily discernible to most people in an exterior environment, and a 10 dB change is perceived as a doubling (or halving) of the sound.

Table 4.12-AA: Noise Perceptibility

Noise Level	Listener Perception
± 3 dB	Threshold of human perceptibility
± 5 dB	Clearly noticeable change in noise level
± 10 dB	Half or twice as loud
± 20	Much quieter or louder

Source: Bies and Hansen 2009
Key:
dB = decibels

Sensitive Receptor

A **Sensitive Receptor** is defined as a single or multi-family dwelling unit, place of public assembly (a legally permitted place where 100 or more people gather together in a building or structure for the purpose of amusement, entertainment, or retail sales), church, institution, school, or hospital.

Vibration

Vibration is defined as the mechanical motion of the ground, or buildings or other types of structures, that is induced by the operation of mechanical devices or equipment. Vibration generally results in an “oscillatory” motion, in terms of the displacement, velocity, or acceleration of the ground (or structure), that causes a person to be aware of the vibration by means such as, but not limited to, sensation by touch or visual observation of moving objects.

The effects of ground-borne vibration include movements of building floors, rattling of windows, and shaking of items on shelves or hangings on the walls. In extreme cases, vibration can cause damage to buildings. The noise radiated from the motion of the room surfaces is called ground-borne noise. Table 4.12-2 presents typical levels of ground-borne vibration, vibration sources, and responses.

Table 4.12-2: Typical Levels of Ground-borne Vibration

Response	Velocity Level[a]	Typical Sources (at 50 feet)
Minor cosmetic damage of fragile buildings	100	Blasting from construction projects
Difficulty with tasks such as reading a video display terminal screen	90	Bulldozers and other heavy tracked construction equipment
Residential annoyance, infrequent events	80	Rapid transit, upper range
Residential annoyance, frequent events	70	High speed rail, typical

Table 4.12-2: Typical Levels of Ground-borne Vibration

Response	Velocity Level[a]	Typical Sources (at 50 feet)
Approximate threshold for human perception	60	Bus or truck, typical
None	50	Typical background vibration

Source: Adapted from Figure 7-3 (FHWA 2006).
Note:
[a] Root mean square (RMS) Vibration Velocity Level in vibration decibels (VdB) relative to 10^{-6} inches per second.

Similar to noise, vibration varies based on the nature of the structure affected (i.e., the weight of the building), soil conditions, layering of the soils, the depth of groundwater table, etc.

4.12.2 Environmental Setting

Noise-Sensitive Land Uses

Noise sensitive land uses, as defined by the Noise Elements of the Kern County General Plan (KCGP), the Metropolitan Bakersfield General Plan (MBGP), and adopted specific plans in the Project Area include residential areas, schools, convalescent and acute care hospitals, retirement homes, long-term medical or mental facilities, parks and recreation areas, and churches.

Effects of Noise

The effects of noise on people can be grouped into four general categories:

- Subjective effects of annoyance, nuisance, dissatisfaction;
- Interference with activities such as speech, sleep, learning;
- Physiological effects such as startling; and
- Physical effects such as hearing loss.

In most cases, environmental noise produces effects in the first two categories of subjective effects and interference with activities only; however, workers in industrial plants might experience physiological effects of noise. No satisfactory way exists to measure the subjective effects of noise, or to measure the corresponding reactions of annoyance and dissatisfaction. This lack of a common standard is due primarily to the wide variation in individual thresholds of annoyance and habituation to noise.

Noise can interrupt ongoing activities and can result in community annoyance, especially in residential areas. In general, most residents become highly annoyed when noise interferes significantly with activities such as sleeping, talking, noise-sensitive work, and listening to the radio, TV, or music.

Physical damage to human hearing begins at prolonged exposure to noise levels higher than 85 dB. Exposure to high noise levels affects the entire human system, with prolonged noise exposure in excess of 75 dB increasing body tensions and thereby affecting blood pressure, functions of the heart, and the nervous system. In comparison, extended periods of noise exposure above 90 dB could result in permanent hearing damage. People may consider louder environments adverse, but in many cases people will accept the higher levels associated with more noisy urban residential or residential-commercial areas (60 to 75 dB) or urban or industrial areas (65 to 80 dB).

Existing Environment

Noise

Major noise sources in the Project Area include Interstate 5, state highways, railroads, airports, and existing commercial/industrial operations (including existing oil and gas exploration/production activities and related facilities). Existing ambient noise levels within the Project Area vary considerably depending on distance from major noise sources and the noise generation characteristics of contributing noise sources at any given location. The noise environment in the Project Area has been characterized by conducting ambient noise level measurements at various locations within the Project Area and quantifying typical noise levels from the major sources that affect the Project Area.

Ambient noise monitoring was conducted between January 7, 2015, and January 21, 2015, at 18 locations within the Project Area. Noise monitoring sites were selected to represent typical acoustic settings within the Project Area where oil and gas exploration and production activities either already occur or could occur in the future, and included six locations in the Western Subarea, six locations in the Central Subarea, and six locations in the Eastern Subarea. Noise monitoring was conducted using unattended automated equipment that measured ambient noise levels continuously for a minimum period of 24 hours at each site. Figure 4.12-1 depicts the locations where ambient noise measurements were collected. These measurements are conservative, as the ambient noise levels may have risen in these areas due to increase in traffic noise or other changes in the area, with most areas not experiencing any changes over the last four years.

A detailed description of the noise monitoring sites, aerial photographs showing the site locations, noise sources affecting the site, and measured noise levels is presented in the Environmental Noise Assessment, provided in Appendix V-1 of the 2015 FEIR (SREIR Volume 4).

Noise monitoring equipment consisted of Larson-Davis Laboratories Model LDL 820 sound level analyzers equipped with Bruel & Kjaer (B&K) Type 4176 half-inch diameter microphones. Microphones were located on tripods at approximately 5 feet above ground and were equipped with random incidence correctors so that noise levels from sources in all directions could be accurately measured. The monitors were calibrated with a B&K Type 4230 acoustical calibrator to ensure the accuracy of measurements. The equipment complies with applicable specifications of the American National Standards Institute for Type 1 sound measurement systems.

Table 4.12-3 summarizes ambient noise monitoring results. Noise measurement data are described in terms of the equivalent energy (L_{eq}), maximum (L_{max}) and L_{90} noise level descriptors. The L_{eq} and L_{max} describe energy average and maximum noise levels measured during each hour of the sample periods, respectively. The L_{90} describes the noise level exceeded 90% of the time during each hour, which is generally considered to represent the residual (or background) noise level. Reported maximum noise levels in the absence of identifiable single noise events were typically caused by intermittent noise events such as a nearby passing vehicle, an occasional aircraft over-flight, and other localized noise sources close to the measuring device (e.g., car doors opening and closing, a barking dog, and a conversation of people standing near the device). The measured DNL for each of the 18 ambient noise monitoring sites is also included in Table 4.12-3.

Table 4.12-3: Ambient Noise Levels

Location	Range of Hourly Noise Levels			DNL (dB)
	L_{eq} (dB)	L_{max} (dB)	L_{90} (dB)	
Western Subarea				
Site 1	42.9 – 58.4	54.8 – 76.5	34.2 – 39.4	58.5
Site 2	45.5 – 63.6	66.7 – 83.1	32.6 – 56.1	63.9
Site 3	52.9 – 66.5	71.4 – 89.9	44.4 – 59.6	67.8
Site 4	38.0 – 55.7	55.8 – 76.0	31.3 – 49.1	56.7
Site 5	40.6 – 68.4	57.8 – 94.2	32.0 – 48.3	59.0
Site 6	41.4 – 56.5	57.6 – 76.5	37.6 – 48.6	55.9
Central Subarea				
Site 7	40.1 – 57.0	55.8 – 86.8	34.5 – 51.4	56.6
Site 8	32.4 – 51.4	45.3 – 68.2	27.9 – 47.8	47.6
Site 9	42.2 – 56.0	47.3 – 74.4	39.9 – 50.3	55.1
Site 10	44.6 – 66.0	59.8 – 87.1	35.9 – 45.6	64.4
Site 11	38.7 – 53.4	47.9 – 72.3	35.7 – 46.1	51.8
Site 12	28.8 – 45.6	39.2 – 65.3	26.5 – 39.9	44.8
Eastern Subarea				
Site 13	29.7 – 55.6	43.6 – 72.6	25.1 – 51.0	50.7
Site 14	36.0 – 49.4	50.6 – 64.7	29.6 – 44.8	50.4
Site 15	43.0 – 56.9	54.8 – 80.1	33.1 – 47.7	55.4
Site 16	38.3 – 46.8	42.8 – 65.2	35.9 – 43.0	48.3

Table 4.12-3: Ambient Noise Levels

Location	Range of Hourly Noise Levels			DNL (dB)
	L_{eq} (dB)	L_{max} (dB)	L_{90} (dB)	
Site 17	34.0 – 50.8	48.5 – 72.4	30.8 – 44.6	50.7
Site 18	34.8 – 45.9	43.2 – 66.8	31.2 – 41.5	46.9
			Average DNL (dB)	**54.7**

Source: Brown-Buntin 2015.
Key:
dB = decibel
DNL = Day-Night Level
L90 = noise level that is exceeded during 90% of the measurement period
Leq = Equivalent Sound Pressure Level
Lmax = Maximum Noise Level

Hourly L_{eq} values represent average noise levels, and these average measurements can be significantly affected by occasional noise events in the vicinity of the monitoring site. Measured DNL values ranged from 44.8 to 67.8 dB at the ambient noise monitoring sites, with an average of 54.7 dB. Generally, the highest ambient noise levels occurred at sites that were located relatively close to major transportation sources or commercial/industrial activities unrelated to oil and gas exploration and production activities (Site 3, Site 10, and Site 15).

Vibration

The vibration environment would be affected by traffic from nearby roadways or train tracks. Heavy trucks can generate vibrations that vary depending on vehicle type, weight, and pavement conditions. For trains, factors such as speed, suspensions on the vehicle, rail and wheel conditions, and soil and subsurface conditions will affect the level of ground-borne vibration. In the areas where oil and gas activities are likely to occur, existing vibration levels would be expected to be low.

Oil and Gas Operations and Noise Effects

Close proximity to oil and gas wells may result in increased levels of noise and/or vibration. Many studies have investigated whether there is a link between oil and gas drilling and various health effects, such as asthma and other respiratory diseases, adverse birth outcomes, cancer, neurodevelopmental effects, cardiovascular disease, endocrine disruption, mental health effects, skin diseases, migraines, fatigue, and throat irritation. However, the majority of these studies focus on emissions of pollutants from oil and gas wells, rather than on noise-specific impacts.

The studies discussed below are based on oil and gas operations outside of California and, as explained in the California Council on Science and Technology (CCST) Summary Report (July 2015), present-day hydraulic fracturing practice and geological conditions in California differ from those in other states and, as such, recent experiences with hydraulic fracturing in other states are not necessarily representative of California activities (CCST 2015). Because California reservoirs are shallower and more permeable, wells tend to be shorter and near vertical as opposed *to horizontal. This means that wells in California take less time to drill and there is therefore less exposure to the loudest oil and gas activities. Thus, any reports or studies listed below that do not directly address California operations are less likely to demonstrate noise impacts for California activities.*

- ***Hays, J., et al. (2017) Public Health Implications of Environmental Noise Associated with Unconventional Oil and Gas Development.*** *This study reviewed scientific literature specific to "unconventional oil and gas development," which was defined to refer specifically to hydraulic fracturing. At the time of publication, the study indicated that "[t]here is currently no peer-reviewed literature on the noise levels and potential health impacts from noise exposure related to oil and gas development." The materials reviewed indicated that hydraulic fracturing produces noise at levels that may increase the risk of adverse health outcomes, including annoyance, sleep disturbance, and cardiovascular disease. The study acknowledges that "[t]here are a large number of noise dependent and subjective factors that make the determination of a dose response relationship between noise and health outcomes difficult," but that "the literature indicates that oil and gas activities produce noise at levels that may increase the risk of adverse health outcomes, including annoyance, sleep disturbance, and cardiovascular disease." Similar to health-related studies that estimate, rather than measure, direct exposure, this study noted that "noise data from actual oil and gas operations are very limited and most are based on estimations rather than actual field measurements."*

- ***Richburg, C. M., and J. Slagley. (2019). Noise Concerns of Residents Living in Close Proximity to Hydraulic Fracturing Sites in Southwest Pennsylvania.*** *This study measured noise level in Southwestern Pennsylvania near non-traditional gas industry sites and found levels exceeding U.S. Environmental Protection Agency (EPA) guidelines. The study does not indicate the precise distance between the sound meters and the source of the measured noise. The study acknowledged that it has a relatively small sample size, and also involves a survey questionnaire that was "pilot tested" and incorporated feedback, but was not "evaluated for reliability. Lastly, this study concerned noise levels associated with nontraditional natural gas sites in Southwestern Pennsylvania, and as such, is inapplicable to noise levels from natural gas development practices specific to California.*

- ***Boyle, M.D., et al. (2017). A Pilot Study to Assess Residential Noise Exposure near Natural Gas Compressor Stations.*** *This study was designed to evaluate the effectiveness of a 1,000-foot setback for unconventional gas development in the Marcellus Shale. It investigated the 24-hour noise levels of a natural gas compressor station relative to residential homes in West Virginia, and determined that homes up to 600 meters away (about 1,968 feet) experienced outdoor noise levels exceeding the EPA's recommended limit to prevent activity interference and annoyance of 55 dB. The study nevertheless found that noise from hydraulic fracturing attenuated to 66.5 dB DNL at 1,000 feet. This study did find levels over the EPA recommended limit, but could only state that the "proposed setback distance of 300 meters (985 feet) for the State of Maryland [may not be sufficient to protect public health] from noise impacts." No evidence was provided showing that the public health was affected and a reasonable setback distance was not provided. This study involved a small sample size of eight homes located within 750 meters of the nearest compressor station evaluated and three homes located within 1,000 meters of, the nearest compressor station evaluated. This was primarily* *due to a "very short deadline the study team had" for completing the analysis. Also, study homes were selected "based on convenience and access," and thus may not be representative of noise levels of all homes in the vicinity. Lastly, this study concerned noise levels associated with unconventional natural gas development in West Virginia, and is thus inapplicable to noise levels from natural gas development practices specific to California.*

- ***Radtke, C., et al. (2017). Noise Characterization of Oil and Gas Operations.*** *This study performed noise monitoring at 23 oil and gas sites in northern Colorado, and determined that "every drilling and hydraulic fracturing site with and without noise walls had average noise measurements at 350 feet (107 meters) that exceeded the current [Colorado] residential daytime and night time noise limits." By contrast, even at these very close distances, the study determined that the vast majority of production sites did not exceed 55 dB. This study acknowledged a number of limitations, including that noise measurements were only taken during 5-second and 15-minute intervals. Although sampling occurred while oil and gas operations were running at full capacity, "variability in noise levels throughout the day or night could not be determined." Without performing 24-hour sampling, accurate noise level results were not captured. Also, this study concerns noise stemming from active oil and gas sites in Northern Colorado, and as such, is inapplicable to noise levels stemming from oil and gas development practices in California.*

- ***Blair, B.D., et al. (2018). Residential Noise from Nearby Oil and Gas Well Construction and Drilling.*** *This study documented the noise levels at four sensitive receptors surrounding a multi-well oil and gas well pad during construction and drilling in a residential area in Colorado. These receptors were located between 1,050 feet and 1,805 feet from the source of the noise. Although the study found that homes in closer proximity to operations experienced noise exposure at levels of concern even with the implementation of sound mitigation best management practices, the L_{eq} measured at the sites ranged from 51.5 to 60.2 dB. The study recognized, however, that results were "based on the continuous sampling at a single large multi-well pad over three months, [and thus] may not be indicative of the noise from O&G operations at other locations with different topography, wind patterns, or noise mitigation strategies." The study recommended that additional studies be performed to determine noise levels "of other communities with large, multi-well O&G construction and drilling sites." Lastly, this study concerns noise stemming from active oil and gas well pads in Colorado, and as such, is inapplicable to noise levels stemming from oil and gas development practices in California.*

4.12.3 Regulatory Setting

The Project Area does not include incorporated cities within Kern County. The Project includes land that is under the jurisdiction of Kern County. Noise standards for the County and federal noise guidelines are addressed in this subsection.

Federal

Federal highway and aircraft guidelines and regulations have been established by Federal Highway Administration (FHWA) (23 Code of Federal Regulations [CFR] 772) and Federal Aviation Administration regulations (18 CFR 150). Federal guidelines and regulations are summarized in

Table 4.12-4. These federal regulations do not apply to Project activities, but are applicable to some existing activities in the Project Area (e.g., aircraft, roadway construction) and also represent useful benchmarks for noise standards used by other agencies.

Table 4.12-4: Federal Guidelines and Regulations for Exterior Noise (dB)

Agency	L_{eq}	DNL
Federal Energy Regulatory Commission	[49]	55
U.S. Department of Transportation (construction noise level at residential land use during daytime)(a)	90	---
Federal Highway Administration	67	[67]
Federal Aviation Administration	[59]	65
U.S. Department of Housing and Urban Development(b)	[59]	65

Sources:
(a) FTA 2006
(b) 24 CFR 51B; HUD 1991
Note: Brackets around numbers (e.g., [59]) indicate a calculated equivalent standard. Because the Federal Highway Administration regulates peak noise level, the DNL is assumed equivalent to the peak noise hour.
Key:
CFR = Code of Federal Regulations
dB = decibels
DNL = Day-Night Level
L_{eq} = Equivalent Sound Pressure Level

- **Federal Highway Administration.** The purpose of the FHWA Noise Abatement Procedures (23 CFR 772) is to provide procedures for noise studies and noise abatement measures to help protect the public health and welfare, supply noise abatement criteria, and establish requirements for information to be given to local officials for use in the planning and design of highways. It establishes five categories of noise-sensitive receptors and prescribes the use of the hourly L_{eq} as the criterion metric for evaluating traffic noise impacts.
- **Federal Transit Administration and Federal Railroad Administration.** Although the Federal Transit Administration (FTA) standards are intended for federally funded mass-transit projects, the impact assessment procedures and criteria included in the FTA Transit Noise and Vibration Impact Assessment Manual (May 2006) are routinely used for projects proposed by local jurisdictions. The FTA and Federal Railroad Administration have published guidelines for assessing the impacts of ground-borne vibration associated with rail projects, which have been applied by other jurisdictions to other types of projects.
- **EPA Recommendations.** In response to a federal mandate, the EPA provided guidance in Information on Levels of Environmental Noise Requisite to Protect Health and Welfare with an Adequate Margin of Safety (National Technical Information Service, 550\9-74-004, EPA, Washington, D.C., March 1974). Commonly referenced as the "Levels

Document," it establishes an L_{dn} of 55 dB as the requisite level, with an adequate margin of safety, for areas with outdoor uses, including residential and recreational areas. This Levels Document does not constitute EPA regulations or standards, but identifies safe levels of environmental noise exposure without consideration of costs for achieving these levels or other potentially relevant considerations. It is intended to "provide State and local governments, as well as the Federal government and the private sector, with an informational point of departure for the purpose of decision-making." The agency is careful to stress that the recommendations contain a factor of safety and do not consider technical or economic feasibility issues and, therefore, should not be construed as standards or regulations. It has, however, been used as the basis of numerous community noise standards and ordinances.

- **Department of Housing and Urban Development.** The Department of Housing and Urban Development Environmental Standards (24 CFR Part 51) set forth the following exterior noise standards for new home construction assisted or supported by the department:
  - 65 L_{dn} or less: acceptable;
  - > 65 L_{dn} and < 75 L_{dn}: normally unacceptable (appropriate sound attenuation measures must be provided); and
  - > 75 L_{dn}: unacceptable.

The Department of Housing and Urban Development's regulations do not contain standards for interior noise levels. Rather, a goal of 45 dB is set forth, and attenuation requirements are geared to achieve that goal.

Occupational Safety and Health Act of 1970

Onsite noise levels are regulated by the federal Occupational Safety and Health Administration. This regulation protects workers from the effects of occupational noise exposure. The noise exposure level of workers is regulated at 90 dB over an 8-hour work shift to protect hearing (29 CFR 1910.95). Employee exposure to levels exceeding 85 dB requires that employers develop a hearing conservation program. Such programs include adequate warning, the provision of hearing protection devices, and periodic employee testing for hearing loss.

Noise Control Act of 1972

This act establishes a national policy to promote an environment for all Americans free from noise that jeopardizes their health and welfare. To accomplish this, the act establishes a means for the coordination of federal research and activities in noise control, authorizes the establishment of federal noise emissions standards for products distributed in commerce, and provides information to the public with respect to the noise-emission and noise-reduction characteristics of such products.

State

California Division of Occupational Safety and Health

The California Division of Occupational Safety and Health implements and enforces the noise exposure limits established by the federal Occupational Safety and Health Administration, as described above, for the state of California.

No state regulations apply to noise specifically from oil and gas operations; however, there are general state guidelines provided by the California Department of Health Services that define acceptable noise levels based on a land use compatibility matrix designed to protect residents and other sensitive land uses from excessive noise levels. These guidelines help to define a threshold for acceptable noise levels for residential areas in the Project Area. The California Department of Health Services has identified DNL or CNEL values of 60 dB or less as normally acceptable outdoor levels for residential areas.

California Noise Control Act of 1973

Sections 46000 through 46080 of the California Health and Safety Code, known as the California Noise Control Act of 1973, declares that excessive noise is a serious hazard to the public health and welfare and that exposure to certain levels of noise can result in physiological, psychological, and economic damage. It also identifies a continuous and increasing bombardment of noise in the urban, suburban, and rural areas. The California Noise Control Act declares that the State of California has a responsibility to protect the health and welfare of its citizens by the control, prevention, and abatement of noise. It is the policy of the state to provide an environment for all Californians free from noise that jeopardizes their health or welfare.

California Department of Transportation Construction Vibration Guidance Manual

One of the most recent references suggesting vibration guidelines is the California Department of Transportation's *Transportation and Construction Vibration Guidance Manual* (Caltrans 2020). The manual provides guidance for determining annoyance potential criteria and damage potential threshold criteria. These criteria are provided in Table 4.12-5 and Table 4.12-6, and are presented in terms of peak particle velocity in inches per second.

Table 4.12-5: Guideline Vibration Annoyance Potential Criteria

	Maximum PPV (in/sec)	
Human Response	**Transient Sources**	**Continuous/Frequent Intermittent Sources**
Barely Perceptible	0.04	0.01
Distinctly Perceptible	0.25	0.04

Table 4.12-5: Guideline Vibration Annoyance Potential Criteria

Human Response	Maximum PPV (in/sec)	
	Transient Sources	Continuous/Frequent Intermittent Sources
Strongly Perceptible	0.9	0.1
Severe	2.0	0.4

Source: Caltrans 2020.
Key:
in/sec = inches per second
PPV = peak particle velocity

Table 4.12-6: Guideline Vibration Damage Potential Threshold Criteria

Structure and Condition	Maximum PPV (in/sec)	
	Transient Sources	Continuous/Frequent Intermittent Sources
Extremely fragile, historic buildings, ancient monuments	0.12	0.08
Fragile buildings	0.2	0.1
Historic and some old buildings	0.5	0.25
Older residential structures	0.5	0.3
New residential structures	1.0	0.5
Modern industrial/commercial buildings	2.0	0.5

Source: Caltrans 2020.
Key:
in/sec = inches per second
PPV = peak particle velocity

Local

Kern County General Plan

The Project Area is located within the KCGP area and, therefore, would be subject to applicable policies and measures of the KCGP. The Noise Element of the KCGP includes goals, policies, and implementation measures related to noise that apply to the Project, as described below.

The KCGP Noise Element identifies residential areas, schools, convalescent and acute care hospitals, parks and recreation areas, and churches as noise sensitive land uses. In noise sensitive areas, exterior noise levels generated by new projects are to be mitigated to 65 dB L_{dn} or less in outdoor activity areas and to 45 dB L_{dn} or less within interior living spaces or other noise sensitive interior spaces.

Chapter 3. Noise Element

Goals

Goal 1. Ensure that residents of Kern County are protected from excessive noise and that moderate levels of noise are maintained.

Goal 2. Protect the economic base of Kern County by preventing the encroachment of incompatible land uses near known noise producing roadways, industries, railroads, airports, oil and gas extraction, and other sources.

Policies

Policy 2. Require noise level criteria applied to all categories of land uses to be consistent with the recommendations of DOSH.

Policy 3. Encourage vegetation and landscaping along roadways and adjacent to other noise sources in order to increase absorption of noise.

Policy 4. Utilize good land use planning principles to reduce conflicts related to noise emissions.

Policy 5. Prohibit new noise-sensitive land uses in noise-impacted areas unless effective mitigation measures are incorporated into the project design. Such mitigation shall be designed to reduce noise to the following levels:

(a) 65 dB L_{dn} or less in outdoor activity areas; and

(b) 45 dB L_{dn} or less within interior living spaces or other noise sensitive interior spaces.

Policy 6. Ensure that new development in the vicinity of airports will be compatible with existing and projected airport noise levels as set forth in the Airport Land Use Compatibility Plan (ALUCP).

Policy 7. Employ the best available methods of noise control.

Implementation Measures

Implementation Measure A. Utilize zoning regulations to assist in achieving noise-compatible land use patterns.

Implementation Measure F. Require proposed commercial and industrial uses or operations to be designed or arranged so that they will not subject residential or other noise sensitive land uses to exterior noise levels in excess of 65 dB L_{dn} and interior noise levels in excess of 45 dB L_{dn}.

Implementation Measure H. Encourage cooperation between the County and the incorporated cities within the County to control noise.

Implementation Measure I. Noise analyses shall include recommended mitigation measure, if required, and shall:

(a) Include representative noise level measurements with sufficient sampling periods and location to adequately describe local conditions.

(b) Include estimated noise levels, in terms of CNEL, for existing and projected future (10 to 20 years hence) conditions, with a comparison made to the adopted policies of the Noise Element.

(c) Include recommendations for appropriate mitigation to achieve compliance with the adopted polices and standards of the Noise Element.

(d) Include estimates of noise exposure after the prescribed mitigation measures have been implemented. If compliance with the adopted standards and policies of the Noise Element will not be achieved, a rationale for acceptance of this project must be provided.

Implementation Measure J. Develop implementation procedures to ensure that requirements imposed pursuant to the findings of an acoustical analysis are conducted as part of the project permitting process.

Metropolitan Bakersfield General Plan

The MBGP, a joint effort between the Kern County Planning and Natural Resources Department and the City of Bakersfield Planning Division, was last adopted on December 11, 2007. The MBGP includes both city and unincorporated County lands. The MBGP describes the community's physical development as well as its economic, social and environmental goals and is currently undergoing an update. The Project Area includes a total of 152,040 acres of unincorporated County lands that are covered under the MBGP (7.41%). Project-related development on unincorporated lands within the MBGP Planning Area would be subject to the following applicable policies and implementation measures of the MBGP, with respect to noise.

Chapter III. Circulation Element

A. Streets

Goals

Goal 3. Minimize the impact of truck traffic on circulation, and on noise sensitive land uses.

Chapter V. Conservation Element

B. Mineral Resources

Policies

Policy 15. Require petroleum production sites in urban areas which are subject to discretionary permits, to install peripheral landscaping to help reduce the noise, dust and visual impacts on adjacent sensitive receptors and public ways (I-4).

Chapter VII. Noise Element

Goals

Goal 1. Ensure that residents of the Bakersfield metropolitan area are protected from excessive noise and existing moderate levels of noise are maintained.

Goal 2. Protect the citizens of the planning area from the harmful effects of exposure to excessive noise, and protect the economic base of the area by preventing the encroachment of incompatible land uses near known noise-producing roadways, industries, railroads, airports and other sources.

Policies

Policy 1. Identify noise-impact areas exposed to existing or projected noise levels exceeding 65 dB CNEL (exterior) or the performance standards described in Table VII-2. The noise exposure contour maps on file at the City of Bakersfield and County of Kern indicate areas where existing and projected noise exposures exceed 65 dB CNEL (exterior) for the major noise sources identified (I-1).

Policy 2. Prohibit new noise-sensitive land uses in noise-impacted areas unless effective mitigation measures are incorporated into project design to reduce noise to acceptable levels (I-2, I-3, I-6, I-7).

Policy 3. Review discretionary industrial, commercial, or other noise-generating land use projects for compatibility with nearby noise-sensitive land uses. Additionally, the development of new noise-generating land uses which are not preempted from local noise regulation will be reviewed if resulting noise levels will exceed the performance standards contained within Table VII-2 in areas containing residential or other noise-sensitive land uses (I-3, I-6, I-7).

Policy 5. Encourage vegetation and landscaping along roadways and adjacent to other noise sources in order to increase absorption of noise (I-7).

Implementation Measures

Implementation Measure 2. Review discretionary development plans, programs, and proposals, including those initiated by both the public and private sectors, to ascertain and ensure their conformance to the policy framework outlined in this element.

Implementation Measure 4. Require proposed commercial and industrial uses or operations to be designed or arranged so that they will not subject residential or other noise sensitive land uses to exterior noise levels in excess of 65 dB CNEL and interior noise levels in excess of 45 dB CNEL and so that impacts on noise sensitive uses shall not exceed the performance standards in Table VII-2.

At time of any discretionary approval, such as a request for zone change or subdivision, the developer may be required to submit an acoustical report indicating the means by which the developer proposes to comply with the noise standards. The acoustical report shall:

(a) Be the responsibility of the applicant.

(b) Be prepared by a qualified acoustical consultant experienced in the fields of environmental noise assessment and architectural acoustics.

(c) Include representative noise level measurements with sufficient sampling periods and locations to adequately describe local conditions.

(d) Include estimated noise levels in terms of CNEL and the standards of Table VII-2 (if applicable) for existing and projected future (10 to 20 years hence) conditions, with a comparison made to the adopted policies of the Noise Element.

(e) Include recommendations for appropriate mitigation to achieve compliance with the adopted policies and standards of the Noise Element.

(f) Include estimates of noise exposure after the prescribed mitigation measures have been implemented. If compliance with the adopted standards and policies of the Noise Element will not be achieved, a rationale for acceptance of the project must be provided.

Implementation Measure 5: Develop implementation procedures to ensure that requirements imposed pursuant to the findings of an acoustical analysis are conducted as part of the project permitting process.

Implementation Measure 6: Enforce the Noise Insulation Standards (California Administrative Code, Title 24) and Chapter 35 of the Uniform Building Code concerning the construction of new multiple-occupancy dwellings such as hotels, apartments, and condominiums.

Implementation Measure 10. Standards for Project Noise Impacts for Mobile Sources. A significant increase of existing ambient noise levels affecting existing noise sensitive land uses (receptors), and requiring the adoption of practical and feasible mitigation measures, is deemed to occur where a project will cause:

- An increase of the existing ambient noise level by 5 dB or more, where the existing ambient level is less than 60 dB CNEL;
- An increase of the existing ambient noise level by 3 dB or more, where the existing ambient level is 60 to 65 dB CNEL;

- An increase of the existing ambient noise level by 1.5 dB or more, where the existing ambient level is greater than 65 dB CNEL.

Standards for Project Noise Impacts from Mobile Sources

A significant increase in existing ambient noise levels affecting existing noise-sensitive land use (receptors) and requiring the adoption of practical and feasible mitigation measures is deemed to occur where a project would cause:

- An increase in the existing ambient noise level by 4 dB or more, where the existing ambient level is less than 60 dB CNEL;
- An increase in the existing noise level by 3 dB or more, where the existing ambient level is 60 to 65 dB CNEL; or
- An increase in the existing ambient noise level by 4.5 dB or more, where the existing ambient level is greater than 65 dB CNEL.

Standards for Cumulative Noise Impacts for Mobile Sources

A project's contribution to noise increase would normally be considered cumulatively considerable and considered significant when ambient noise levels affect noise sensitive land uses (receptors) and when the following occurs:

- A project increases the ambient (cumulative without project) noise level by 1 dB or more; or
- The cumulative with project noise levels cause the following:
  - An increase of the existing ambient noise level by 5 dB or more, where the existing ambient level is less than 60 dB CNEL;
  - An increase of the existing ambient noise level by 3 dB or more, where the existing ambient level is 60 to 65 dB CNEL; or
  - An increase on the existing ambient noise level by 1.5 dB or more, where the existing ambient level is greater than 65 dB CNEL.

3.6. Mineral and Petroleum

Policies

Policy 4. Noise abatement measures shall be required of all resource management activities which would adversely affect adjacent land uses or wildlife habitat.

F. Mineral and Petroleum Extraction

Implementation Measures

Implementation Policy 1. The City and County shall revise, within two years from adoption of this plan, mineral and petroleum extraction regulations and provisions of their respective floodplain Zoning Ordinances consistent with all plan policies and incorporate the following features:

a) Noise limits when adjacent to highly sensitive and sensitive land uses.

Kern County Specific Plans

As of 2020, Kern County has adopted 37 Specific Plans for properties within the Project Area. These Specific Plans are intended to be an amplification of the goals and policies of the KCGP and are, therefore, consistent therewith. As depicted in Figure 4.10-3 in Section 4.10 of the 2015 FEIR (SREIR Volume 3), less than 8% of the Project Area is located wholly or partially within adopted Specific Plan areas. Future oil and gas exploration and production activities that would be authorized under the proposed Amendment to Chapter 19.98 (Oil & Gas Production) of the Kern County Zoning Ordinance (Zoning Ordinance) that would be located within the boundary of an adopted specific plan would be regulated according to County zoning, with the exception of the specific plans identified as Tier 5.

Kern County Zoning Ordinance

Chapter 19.98 (Oil and Gas Production) of the Kern County Zoning Ordinance contains the procedures and standards that apply to all exploration drilling and production activities related to oil, gas, and other hydrocarbon substances carried out in unincorporated Kern County. At present, Chapter 19.98's general development standards and conditions relevant to noise require the following:

- **Specific well setback distances from various structures** (19.98.060.A). No oil or gas well shall be drilled within 100 feet of any public highway or building not necessary to the operation of the well, or within 150 feet of any dwelling, or within 300 feet of any building used as a place of public assembly, institution, or school, or within 50 feet of any building utilized for commercial purposes constructed prior to the commencement of such drilling, without the written consent of the owner of such structure.

  Required setbacks from buildings and public highways for new oil and gas wells in various zone districts are presented in Table 3-1 in Chapter 3 of this SREIR.

- **Material delivery restrictions** (19.98.050.J). Whenever a well is located within 500 feet from an existing dwelling unit, except in case of an emergency, no materials, equipment, tools, or pipe used for either drilling or production operations shall be delivered to or removed from the drilling site, except between the hours of eight (8:00) a.m. and eight (8:00) p.m., unless otherwise required by the California Division of Oil and Gas.

- **Electric motors/Muffled engines** (19.98.050.K). Pumping wells shall be operated by electric motors or muffled internal combustion engines.

Kern County Ordinance Code – Health and Safety – Title 8

Chapter 8.36, Noise Control (Section 8.36.020, Prohibited Sounds) of the Ordinance Code of Kern County prohibits the creation of construction noise between the hours of 9:00 p.m. and 6:00 a.m. on weekdays and between the hours of 9:00 p.m. and 8:00 a.m. on weekends, which is audible to a person with average hearing faculties or capacity at a distance of 150 feet from the construction site, if the construction site is within 1,000 feet of an occupied residential dwelling except for emergency work or when the Development Services Director or his designated representative provides an exemption for a limited time.

4.12.4 Impacts and Mitigation

Methodology

The California Environmental Quality Act (CEQA) requires determination of the significance of noise impacts associated with proposed projects. The process of assessing the significance of noise impacts associated with the Project involves establishing thresholds at which significant impacts on noise-sensitive uses may occur. Noise levels associated with construction and operational activities related to the Project were predicted and compared to these significance thresholds.

Methodology and assumptions from the Environmental Noise Assessment (Appendix V-1 of the 2015 FEIR [SREIR Volume 4]) are summarized in Table 4.12-7.

Table 4.12-7: Methods and Assumptions for Noise

Methods/Assumptions	Analytical Framework for Measuring Noise
Equipment and methods to assess noise generation during construction and operation of future oil and gas wells and related facilities.	– Larson Davis Model 824 and Model LDL 820 sound level meters – SoundPLAN acoustic modeling software used for modeling construction and operational noise – Calculations based on FHWA Highway Construction Noise Handbook
Modeling assumptions	– Flat topography – Ground absorption factor 0.5 – 40 degrees Fahrenheit – 50% relative humidity – 5-foot receiver height – 10-foot noise source height

Key:
FHWA = Federal Highway Administration

Noise levels associated with oil and gas production activities were measured by Brown-Buntin Associates, Inc., at 18 locations throughout Kern County from January 7, 2015, to January 21, 2015 (Brown-Buntin 2015). For each activity, noise level measurements were taken in a minimum of four different directions from the activity to document the loudest direction of noise. The activities measured included construction phase activities such as production well drilling (during both well advancement and pulling out of the borehole), exploratory well drilling, well stimulation and well workover activities, and operational-phase activities, such as active production wells (both electric and diesel powered), including use of ancillary facilities and equipment (e.g., pipelines and tanks). Well plugging, abandonment, and decommissioning activities were not specifically measured because these ~~*would be similar to, and therefore have been determined to, produce*~~ noise levels ~~*that*~~ are equivalent to or less than construction-phase activities.

Noise measurements were conducted using a Larson Davis Model 824 Sound Level Meter to document the spectral (frequency) components of each source. The meter was calibrated prior to use with a Larson Davis CA250 calibrator to ensure the accuracy of the measurements. A windscreen was used over the microphone to avoid interference ~~*resulting*~~ from wind ~~*sources*~~ during outdoor measurements.

Project-related noise levels were calculated by Brown-Buntin Associates, Inc., using the SoundPLAN acoustic model. SoundPLAN utilizes measured spectral sound power levels to determine noise exposure from a noise source. Inputs to the model include noise source spectral sound power levels, topography, atmospheric conditions, ground absorption factors, shielding from existing walls or buildings, noise source height, and receiver height. The modeling included the conservative assumption that the topography was flat. ~~*Using the SoundPLAN noise model, which is based on ISO 9613, is overly conservative on sites with a flat topography or steady downward slope from turbine to receiver.*~~ It is also important to recognize that, in scenarios where the topography is relatively flat or there is a steady slope away from a sound source located on a hill, ~~*these methods*~~ *the SoundPLAN ISO 9613 method is overly conservative and* can over-predict noise by up to 6 dB, even where line-of-sight from the receiver location to the turbine hub is not broken. The model included the loudest observed noise measurement for each source as a basis for modeling potential Project-related noise exposure. The model included no shielding as a result of buildings or other structures that may be in the sound propagation path. These assumptions represent a highly conservative, worst-case assessment ~~*in regards to*~~ *regarding* noise propagation from individual sources.

For the noise modeling effort, construction activities included well pad site preparation activities, such as geophysical surveys, land clearing and grading for well pads, access road construction or improvement, construction of temporary drilling sumps, installation, completion, and initial operation (testing) of new wells and ancillary equipment, installation of temporary equipment and facilities such as storage tanks or drilling sumps, and spill prevention activities. Construction activities result in temporary elevated noise levels.

Ground-level activities, such as land clearing, site preparation, and access road construction, require equipment including bulldozers, excavators, loaders, and dump trucks. The local increase in general vehicle traffic could be a source of noise impact, depending on the number of trips to and from a specific area.

Although construction activities for a particular well, group of wells, or storage tank area may be temporary and somewhat brief (i.e., on the order of several weeks to several months), staggered development of multiple wells or other oil and gas facilities within a particular area could occur over the course of several years.

Construction activities included well workovers and re-working. Well workover involves repair or maintenance of an existing production well for the purpose of restoring, prolonging or enhancing the production of the well, while re-working involves well changes including the removal and replacement or alteration of the well casing. Typically, the loudest source of noise associated with a drill rig is the power generation equipment, which is typically a diesel-powered internal combustion engine.

Well stimulation processes primarily consist of hydraulic fracturing treatments and acid well stimulation treatments (i.e., acid fracturing and acid matrix). Equipment used for these treatments is similar to that used for well construction. Stimulation may also involve more vehicles and equipment at a particular well site than during construction. Equipment used for well stimulation treatment may include mobile water tanks, truck-mounted blending units, sand storage trailers, truck-mounted pumps, generators, control vans, and other vehicles. Up to 20 truck-mounted pumps may be present at a well site for a large operation. Acid well stimulation treatments may require a similar amount of equipment and numbers of vehicles, although the types of equipment and vehicles may vary.

Well decommissioning and abandonment entails plugging and abandoning wells once they are no longer productive. Well decommissioning and abandonment involves removal, disassembly, and salvage or disposal of pumping units, well cellars, pipelines, and associated infrastructure, plugging the well with concrete and steel plates, and restoration of the well pad. Equipment used for decommissioning and abandonment varies somewhat from that used for construction, but would be expected to generate similar or lesser noise levels. Typical equipment used onsite for decommissioning and abandonment may include bulldozers, motor graders, front-end loaders, cement and dump trucks, and well workover rigs.

Noise levels resulting from construction equipment are dependent on several factors, including the number and type of equipment operating, the level of operation, and the distance between sources and receptors. The loudest equipment during construction would contribute to a composite average or equivalent site noise level.

In response to comments on the 2015 FEIR, WJV Acoustics, Inc., prepared an acoustical analysis to specifically analyze noise impacts from gas flares, included in Appendix V-3 of the 2015 FEIR, (SREIR Volume 4). The Flare Noise Assessment was prepared to supplement the previously submitted environmental noise assessment prepared by Brown-Buntin Associates, Inc., to determine if significant noise impacts would occur as a result of the use of various types of gas flares and to describe mitigation measures for noise if significant impacts are determined. As part of the Flare Noise Assessment, noise levels associated with gas flare activities were measured at several locations throughout Kern County. For each analyzed flare, noise level measurements were taken in multiple directions from the flare to account for variations that occur as a result of localized conditions, such as wind or site-specific shielding. In addition, for each modeled gas flare, the loudest observed measurement was utilized as a basis for modeling potential project-related noise exposure. As a result, gas flare noise levels disclosed in the Flare Noise Assessment represent a worst-case assessment of gas flare noise exposure.

Thresholds of Significance

In 2018, the California Natural Resources Agency finalized updates to the CEQA Guidelines, including to Appendix G. The thresholds identified in Appendix G of the guidelines indicate that a project would normally be considered to have a significant impact if it would result in:

- Generation of a substantial temporary or permanent increase in ambient noise levels in the vicinity of the Project in excess of standards established in the local general plan or noise ordinance, or applicable standards of other agencies;
- Generation of excessive ground-borne vibration or ground-borne noise levels;
- For a project located within the vicinity of a private airstrip or an airport land use plan or, where such a plan has not been adopted, within 2 miles of a public airport or public use airport, the project would expose people residing or working in the Project Area to excessive noise levels.

Like many lead agencies, Kern County has exercised its discretion to formulate significance thresholds by using language from Appendix G of the CEQA Guidelines. Based on these standards, the effects of the Project would be categorized as either a "less than significant impact" or a "potentially significant impact." Mitigation measures are recommended for potentially significant impacts. If a potentially significant impact cannot be reduced to a less than significant level through the application of mitigation, it is categorized as a "significant and unavoidable impact."

Project Impacts

Impact 4.12-1: Generation of a Substantial Temporary or Permanent Increase in Ambient Noise Levels in the Vicinity of the Project in Excess of Standards Established in the Local General Plan or Noise Ordinance, or Applicable Standards of Other Agencies

This threshold applies to both construction and ~~*project*~~ operation and requires the County to evaluate whether the Project will result in increases in ambient noise levels "in excess of the standards established in the local general plan or noise ordinance, or applicable standards of other agencies." The CEQA Guidelines provide no definition of what constitutes a substantial noise increase and instead direct preparers to the local general plan or noise ordinance. In accordance with the CEQA Guidelines, noise impacts are, therefore, analyzed against the standards established in the local general plan with consideration of the specific type of 24-hour operation created by oilfield construction activities.

~~*The KCGP applies an exterior noise level standard of 65 dB DNL for defined noise-sensitive receptors. The MBGP uses a 65 dB CNEL standard, as well as an incremental noise standard ranging from 1.5 to 5 dB, depending on existing ambient noise conditions. Project activities would occur in both the KCGP and the MBGP planning areas, and this type of project activity, specifically construction, is unlike the other types of construction activity highlighted in the General Plans. The adopted standard will allow the property owner the use and enjoyment of their outdoor areas, such as the backyard of a single family house or conducting church services. Both the KCGP and MBGP establish an exterior noise threshold of 65 dB, which allows property owners normal use of their property and an interior limit of 45 dB, which avoids health hazards for occupants inside the structures. This is consistent with the Building Code, which is designed to meet the 45 dB limit with California Administrative Cod, Title 24 standards for energy efficiency.*~~

The KCGP applies an exterior noise level standard of 65 dB DNL for defined noise-sensitive receptors. ~~*The*~~ *This is consistent with the* MBGP*, which* uses a 65 dB CNEL standard*. The adopted standard allows the property owner the use and enjoyment of their outdoor areas, such as the backyard of a single family house or conducting church services. The adopted standard also works in tandem with the County's adopted limit for interior noise of 45 dB DNL. When sound is limited to 65 dB DNL at the exterior of a structure, the interior noise levels are typically limited to 45 dB DNL. Although construction methods and materials vary based upon location and period of construction, typical construction complying with building code standards can be expected to provide an outdoor-to-indoor noise level reduction of at least 20 dB. This is the lower end of the national average of outdoor-to-indoor noise reduction. Demonstration of project compliance with the exterior noise level criterion would therefore ensure project compliance with the interior noise level criterion of 45 dB DNL. The Project's noise impacts must therefore be evaluated against an absolute 65 dB DNL standard.*

The use of 65 dB DNL is also appropriate because it not only accounts for noise levels throughout a 24-hour period, but adds 10 dB to nighttime (10 P.M. to 7 A.M.) noise levels. By adding 10 dB to the proposed well activity, the DNL does take in account the higher sensitivity to noise during the nighttime hours. The 10-dB penalty applied during the nighttime hour accounts for increased sensitivity to noise exposure occurring during nighttime hours, and therefore does address the potential for sleep disturbance.

In addition to the County's adopted 65 dB DNL noise limit, noise impacts from oil and gas activities are also analyzed to determine whether the activities will significantly increase existing ambient noise. Kern County does not have an adopted incremental noise standard. However, Project activities, specifically construction, are unlike the other types of construction activity highlighted in the General Plans. Therefore an incremental noise standard is appropriate.

The MBGP uses an incremental standard ranging from 1.5 to 5 dB depending on existing ambient noise conditions, but this standard is not generally applicable to Project activities which occur in both the KCGP and MBGP planning areas. For areas with an existing ambient less than 60 dB, the MBGP imposes a 5 dB incremental standard.

~~*Ambient noise measurements vary widely throughout the Project Area, with an a*~~Average *ambient noise in the Project area is* ~~*of*~~ 54.7 dB DNL. It is therefore appropriate to assess the noise effects of the Project against the 5 dB increase standard~~*, which the MBGP applies when ambient noise is less than 60 dB CNEL*~~. An increase of 5 dB is also the point at which a change in ambient sound becomes readily perceptible, while smaller changes are barely perceptible. It is also appropriate to use a 1 dB increase for locations where ambient noise is greater than or equal to 65 dB. This is more conservative than the MBGP's 1.5 dB increase standard in locations with ambient noise levels of 65 dB or greater.

These incremental noise increase standards are appropriate for this SREIR because Project activities—specifically, Project construction activities—are unlike other types of construction activities analyzed and considered in the KCGP or MBGP. The County has determined that Project activities are a "unique construction activity," defined as an activity with characteristics not normally associated with construction. As detailed in Chapter 3.5.3, Construction Activities in Detail, drilling operations are conducted 24 hours a day, with continuous drilling. A drill rig could be as tall as 80 feet and involves continuous noise as the drill is advanced into the ground and the drilling mud is pumped. The closest conventional analog to well drilling is concrete mixing trucks used to pour foundations for wind or residential developments. However, these concrete mixing trucks are typically only used for short periods and are located near to the ground. By contrast, drilling rigs may operate continuously and may be as tall as 80 feet. This increased height causes noise to disperse out from the property in a pattern distinct from conventional construction noise.

The characteristics of oil field construction activities that have been classified as a "unique construction activity" are:

- Height of drill rig;
- Rotational effect of the continuous drilling and continuous pumping of fluids;
- Round-the-clock duration of construction activities for multiple weeks and days; and
- Infeasibility of noise shielding due to decreased efficiency of drilling rigs.

Due to the unique character of oil and gas activities and the varying General Plan policies applicable throughout the Project Area, it is appropriate to implement an incremental noise standard in addition to the applicable limit of 65 dB at the property line of the sensitive receptor in the KCGP and the MBGP.

The Project's effects will thus be considered significant if any of the following occur:

- The noise from Project activities exceeds 65 dB at the property line of the sensitive receptor;
- Where the existing ambient noise level is less than 65 dB, the noise associated with Project activities will result in a greater than 5 dB increase over existing ambient levels at the property line of the sensitive receptor; or
- Where the existing ambient noise level is at or above 65 dB, the noise associated with Project activities will result in a greater than 1 dB increase over existing ambient levels at the property line of the sensitive receptor. As 1 dB cannot be perceived, it is the equivalent of the existing noise level.

Temporary Increases (Construction Impacts)

Short-term construction noise impacts could result from land clearing and grading for well pads and work areas; construction/maintenance of access roads; construction of accessory facilities (including pipelines, electrical transmission lines, drilling sumps or temporary storage tanks); transporting the drilling rig, associated equipment, workers, and materials to the well pad site; well drilling; and construction equipment operations. Due to the complexity of drilling and the hazards associated with leaving a well unattended during the drilling process, drilling operations are typically conducted 24 hours a day. Depending on the depth of the formation, some wells may take less than 24 hours to drill, while some wells in deeper formations may take up to 60 days to drill. Construction noise is usually made up of intermittent peaks and continuous lower levels of noise from equipment cycling through use.

While new oil and gas exploration and production wells and related facilities could be located within any of the zone districts within the Project Area, historically 95% of such development has occurred within core areas. Of this total, 90% has occurred in Tier 1 areas, where the oil and gas activity is the primary land use and well and activity densities preclude almost all other uses. Of the 2,697 new oil and gas exploration and production wells anticipated to be constructed annually within the Project Area, 2,430 (90%) would be located within Tier 1 areas, while 25 new oil and gas exploration and production wells (less than 1%) would be located in Tier 4, which, with a predominance of urban uses, is where most sensitive receptors would be expected to occur.

During construction, noise from construction activities could impact sensitive receptors if such uses are located in the immediate area. Using the noise levels associated with oil and gas well construction and development and the methodology described above, distances from individual Project-related noise sources to the 50 dB, 55 dB, *60 dB* and ~~*60*~~ *65* dB contours were calculated using SoundPLAN. These distances were calculated using conservative assumptions, including that measurements were taken from the loudest direction of the equipment while each individual piece of equipment was operated at its maximum noise level. These conditions are therefore more extreme than normal operating conditions and, over any given period of time, noise levels from drilling operations can vary widely. Noise levels are typically at a maximum during active well advancement. Noise levels decrease while additional lengths of drill pipe are added, the drillstring is being retracted, or during times of rig maintenance. Because the contour distances are based on measurements obtained at the loudest location during the loudest periods of operation, they should be considered a worst-case assessment of actual noise levels. The contour distances assume maximum noise levels, continuously, over a 24-hour period.

The results of the calculations are provided in Table 4.12-8.

Table 4.12-8: Construction Noise Exposure Levels

	Distance (feet) to L_{eq} Contour		Distance (feet) to DNL Contour	
Activity	50 dB	55 dB	60 dB	65 dB
Drilling (Well Advancement)	3,550	2,270	2,500	1,550
Drilling (Pull Out Of Well/Borehole)	2,130	1,300	1,320	820
Large-Scale Exploratory Drilling[(a)]	7,250	4,750	5,270	3,270
Well Workover (Maintenance)	2,150	1,350	1,500	930
Well Stimulation (Hydraulic Fracturing)	2,700	1,650	1,760	1,090

Source: Brown-Buntin 2015.
Note:
(a) Kenai Drill Rig #7
Key:
dB = decibel
DNL = day-night level
Leq = equivalent sound pressure level

It should be noted that at increased distances from a modeled noise source (distances greater than 1,000 feet), the modeled results should be considered with tolerance limitations of +/- 5 dB. At such distances from the noise source, variables such as atmospheric conditions (including wind speeds and direction), topography and ground absorption could cause modeled results to vary, thereby warranting use of the tolerance limitation adjustment of +/- 5 dB.

The Kenai Rig, included in Table 4.12-8, is one of the largest operating drill rigs in the United States, and is used for exploratory drilling at depths up to 25,000 feet below surface elevation. Noise levels produced by such drill rigs are substantially higher than those produced by more typical rigs commonly utilized in the Project Area. It is not expected that a rig of this size would be commonly used within the Project Area because average well depths are 2,305 feet in the Western Subarea, 10,414 feet in the Central Subarea average, and 2,220 feet in the Eastern Subarea. As the rigs are not owned by the potential applicants but rather leased from contractors, and only a limited number are available in California at any given time, it would be infeasible to specify which types of rigs can be used for particular drilling depths. Therefore, for modelling and assessment purposes, the loudest rig—the Kenai Rig—was used to determine *mitigation trigger distances for noise from large-scale exploratory drilling* ~~appropriate setbacks for noise reduction to sensitive receptors~~. The noise levels and contour for the Kenai Rig were therefore included as part of the conservative modeling and assessment methodology appropriate for a project-level environmental impact report.

Noise from construction of other ancillary activities, such as pipelines, extensions of electric services to well sites, construction or maintenance of access roads, drilling of injection wells, etc., was determined to result in noise levels that were similar to or less than the measured construction noise scenarios listed in Table 4.12-8.

Well Pad Preparation

Prior to the installation of a well, a well pad site must be cleared and graded to make room for the placement of the necessary equipment and materials to be used during the drilling and development of the well. Site preparation would generate noise from bulldozers, backhoes, and other types of construction equipment. The A-weighted sound pressure levels for the construction equipment that typically would be used during well pad preparation are presented in Table 4.12-9 along with the estimated sound pressure levels at various distances from the site.

Table 4.12-9: Estimated Construction Noise Levels at Various Distances for Well Pad Preparation

Construction Equipment	Qty.	Usage Factor %	L_{max} SPL @ 50 feet (dBA)	Distance in Feet/SPL (dBA)					
				50 (adj.)	250	500	1,000	1,500	2,000
Excavator	1	40	81	77	63	57	51	47	45
Bulldozer	1	40	82	78	64	58	52	48	46
Water Truck	1	40	76	72	58	52	46	42	40
Dump Truck	2	40	76	75	61	55	49	45	43
Pick-Up Truck	2	40	75	74	60	54	48	44	42
Chain Saw	2	20	84	80	66	60	54	50	48
Composite Noise Level				**84**	**70**	**64**	**58**	**55**	**52**

Source: FHWA 2006.
Key:
adj. = adjusted to quantity
dBA = A-weighted decibels
L_{max} = maximum noise level
Qty. = quantity
SPL = sound pressure level

Drilling

Drilling operations involve various sources of equipment noise. The types and quantities of this equipment are presented in Table 4.12-10, along with the estimated A-weighted individual and composite sound pressure levels that would be experienced at various distances from the operation.

Table 4.12-10: Estimated Construction Noise Levels at Various Distances for Well Drilling

Construction Equipment	Qty.	Sound Power Level	Distance	Distance in feet/SPL[a] (dBA)					
				50 (adj.)	250	500	1,000	1,500	2,000
Rig Drive Motor [b]	1	105	0	71	57	51	45	41	38
Generator [b]	3	81	0	51	37	31	25	22	19
Top Drive	1	85	5	65	51	45	39	35	33
Draw Works	1	74	10	60	46	40	34	30	28
Triple Shaker	1	85	15	75	61	55	49	45	43
Composite Noise Level				**76**	**62**	**56**	**50**	**47**	**44**

Notes:
[a] SPL = sound pressure level.
[b] sound power level.
Key:
adj. = adjusted to quantity
dBA = A-weighted decibels

Hydraulic Fracturing

Table 4.12-11 presents the estimated noise levels that may be experienced at various distances from a hydraulic fracturing operation, based on 20 pumper trucks operating at a sound power level of 110 dBA and 20 pumper trucks operating at a sound power level of 115 dBA.

Table 4.12-11: Estimated Construction Noise Levels at Various Distances for Hydraulic Fracturing

Construction Equipment	Qty.	Sound Power Level [b] (dBA)	Distance (feet)	Qty. Adjusted Sound Level	Distance in feet/SPL[a] (dBA)					
					50	250	500	1,000	1,500	2,000
Pumper Truck	20	110	3	123	99	85	79	73	69	67
Pumper Truck	20	115	3	128	104	90	84	78	74	72

Source: Confidential Industry Source.
Notes:
[a] SPL = sound pressure level.
[b] sound power level.
Key:
dBA = A-weighted decibels

Ambient Increase

The CEQA Guidelines require that noise impacts be evaluated against the standards developed by the pertinent local agency. As discussed above, because Project activities may occur both inside and outside of the boundaries of the MBGP, and because Project activities are a “unique construction activity,” the noise effects of the Project will be subject to both an absolute limit of 65 dB and an incremental increase standard. *While less than 8% of the Project Area is within the*

MBGP, it is appropriate to analyze the incremental increase caused by Project activities on the existing ambient noise level. When a Project activity is proposed in an area with an ambient noise level under 65 dB, the noise impact of construction activities will be considered significant if it will increase the ambient noise by more than 5 dB. If the ambient noise is at or above 65 dB, the Project construction activities may increase the ambient noise level by no more than 1 dB.

Noise levels would fluctuate depending on the phase of construction, equipment type and duration of use, and distance between the noise source and receptor. Changes of 1 to 3 dB are detectable under quiet, controlled conditions, and changes of less than 1 dB are usually indiscernible. A 3 dB change in noise levels is considered the minimum change that is detectable by human hearing in outside environments. A change of 5 dB is readily discernible to most people in an exterior environment, and a 10 dB change is perceived as a doubling (or halving) of the sound (Bies and Hansen 2009). Decibels are logarithmic units. Consequently, sound levels cannot be added by ordinary arithmetic means. The sound pressure level from two equal sources is 3 dB greater than the sound pressure level of just one source. Therefore, two trucks producing 90 dB each will combine to produce 93 dB, not 180 dB. In other words, a doubling of the noise source produces only a 3 dB increase in the sound pressure level. Studies have shown that this increase is barely detectable by the human ear (FHWA 2011).

An analysis of the increase in ambient noise levels is necessarily dependent on a site-specific acoustical assessment; in other words, it is impossible to determine the sound limit applicable to a particular Project activity without determining the existing ambient level at that Project site. Therefore, a conservative approach of ~~*setback triggers*~~ *mitigation trigger distances* for noise reduction mitigation ensures the protection of health and safety from noise impacts for sensitive receptors.

Nevertheless, the 2015 Environmental Noise Assessment identified 18 study sites that were representative of typical ambient noise conditions within the Project Area. However, these locations are not comprehensive. It is possible that the ambient noise levels at a particular site within the Project Area could be either lower or higher than the sites sampled for the 2015 Environmental Noise Assessment. While the ambient levels at these sites can disclose the range of Project sound levels that would not result in a significant impact, the actual level for any specific site can only be determined based on an individualized study of that location.

As disclosed in the 2015 Environmental Noise Assessment, ambient noise levels were measured throughout the Project Area, with DNL values ranging from 44.8 to 67.8 dB, with an average of 54.7 dB. Generally, the highest ambient noise levels occurred at sites that were located relatively close to major transportation sources or commercial/industrial activities unrelated to oil and gas exploration and production activities (Site 3, Site 10, and Site 15). Based on the site-specific ambient conditions as assessed in the Environmental Noise Assessment (Appendix V-1 of the 2015 FEIR [SREIR Volume 4]), Project noise levels could range from 48.8 to 63.8 dB without creating a significant effect.

Table 4.12-12: Application of County Thresholds to Ambient Noise Study Locations

	DNL (dB)	Noise Exposure Increase (dB)	Project Noise Exposure (dB)	Combined Total Noise (dB)
Lowest Measured Ambient Noise	44.8	5	48.8	49.8
Highest Measured Ambient Noise	67.8	1	63.8	68.8
Average Measured Ambient Noise	54.7	5	58.7	59.7

Key:
dB = decibels
DNL = average day-night level

Incremental change over ambient is generally dependent on site-specific measures, but by using the lowest measured ambient noise level from the 2015 Environmental Noise Assessment, a contour can be generated beyond which any increase is below 5 dB. The lowest measured ambient level was 44.8 dB. Based on the 5 dB incremental standard, Project noise could reach approximately 49 dB (48.8 dB) without resulting in an exceedance. This results in the following screening contours. If these contours are achieved for the respective activity, then the activity will not increase the existing ambient by more than 5 dB.

Table 4.12-12A: Construction Noise Exposure Levels

Activity	***Distance (feet) to 49 dB L_{eq} Contour***
Drilling (Well Advancement)	*3,900*
Drilling (Pull Out Of Well/Borehole)	*2,350*
Large-Scale Exploratory Drilling[(a)]	*7,900*
Well Workover (Maintenance)	*2,355*
Well Stimulation (Hydraulic Fracturing)	*2,965*

Source: WSP 2020.
Note:
(a) Kenai Drill Rig #7
Key:
dB = decibel
Leq = equivalent sound pressure level

~~In the loudest of the study locations, depending on the specific activity, construction activities could be sited from 0.2 to 0.6 miles away without creating a significant effect. In the quietest of the study locations, these distances may more than double to 0.4 to 1.4 miles, depending on the specific activity. Due to this wide variation, it is impossible to impose a setback distance that would ensure~~

~~*a no more than 5 dB increase across all Project locations. In the absence of site-specific acoustical analyses for each Project activity, there are no feasible mitigation measures that would result in a predictable increase in ambient noise levels.*~~

In addition to the existing ambient conditions, site-specific variables, including topography, atmospheric conditions, ground absorption factors, shielding from existing walls or buildings, noise source height, and receiver height, all contribute to the dispersion of sound at a particular location. Therefore, a conservative approach of ~~*setback*~~ *mitigation* trigger~~s~~ *distances* for noise reduction mitigation ensures the protection of health and safety from noise impacts for sensitive receptors.

However, where a *sensitive receptor is located within the noise mitigation trigger distance in Table 4.12-12A* ~~*noise reduction setback cannot be achieved*~~, then a Noise Reduction Report that shows the ambient noise level at the time of activity and accounts for these variables can be provided and a noise standard achieved. The noise standard to achieve through the mitigation will provide that the maximum amount of construction noise would result in a no more than 5 dB increase in ambient noise for locations where the ambient level is less than 65 dB or that would result in no more than a 1 dB increase in ambient noise for locations where the ambient level is at or above 65 dB.

Oil and gas well development could therefore result in temporary increases in ambient noise levels in the vicinity of project construction activities in excess of the 5 dB threshold, depending on the proximity of the sensitive receptor to the construction operation.

Summary

Under existing regulations, construction noise that occurs between 6:00 a.m. and 9:00 p.m. on weekdays, and between 8:00 a.m. and 9:00 p.m. on weekends is exempt from County restrictions. After that time construction noise is prohibited from being audible within 150 feet of the construction site and 1,000 feet of an occupied residential building. Based on the data presented in the tables in this section, all activities described in Table 4.*1*2-8 would be audible within 150 feet from the equipment. Due to the required pump trucks, hydraulic fracturing would be audible at 1,000 feet. Well pad preparation and drilling activities could be audible at 1,000 feet.

In accordance with the Zoning Ordinance, setbacks for oil and gas wells currently are 150 feet from residential dwellings and hospitals and 300 feet from places of assembly, including schools and churches. These land uses are considered sensitive noise receptors. If oil and gas activities were to occur within 150 feet of a residence or 300 feet of a place of assembly, construction noise levels could exceed audible levels if construction were to occur outside of the 6:00 a.m. to 9:00 p.m. framework. In addition, construction noise could exceed the County's 65 dB DNL threshold at residences and places of assembly, even if the current setbacks were observed. Therefore, even with the current setback requirements, construction noise impacts could be significant if construction were to occur between 9:00 p.m. and 6:00 a.m.

The County has adopted an absolute noise limit of 65 dB *DNL* within the property line of the sensitive receptor. Additionally, due to the application of the MBGP noise standards to Project activities within its boundaries and the designation of Project activities as a "unique construction impact," the County has determined that Project activity noise should not increase ambient noise levels by more than 5 dB when the existing ambient noise is below 65 dB or by more than 1 dB when the existing ambient noise level is or exceeds 65 dB.

Implementation of additional noise reduction measures could reduce the Project's impacts to meet the noise standards. These include:

- *Temporary sound attenuation walls or sound curtains around the outside of the well property;*
- *Placement of moveable noise barriers around individual pieces of equipment;*
- *Building berms on the property;*
- *Orientation of drilling equipment, so that the side with the most noise is not facing noise sensitive land uses (in most cases, this is the exhaust);*
- *Use of a hospital grade muffler on exhaust of equipment to quiet or redirect the exhaust; and*
- *Electrification of equipment.*

The effectiveness of each of these reduction measures can vary due to a variety of factors, but in general are understood to reduce noise levels, as described in Table 4.12-12B.

Table 4.12-12B: Estimated Reductions for Identified Measures

	Estimated Reductions (dB)	
Noise Reduction Measure	***Minimum***	***Maximum***
Sound attenuation walls or curtains at edge of well property	*5*	*15*
Sound attenuation barriers at equipment location	*5*	*7*
Berms	*8*	*18*
Orientation of Drilling Equipment	*5*	*10*
Hospital Grade Muffler	*5*	*10*
Electrification of Equipment	*8*	*10*

Source: WSP 2020.
Key:
dB = decibel

While setbacks and noise attenuation strategies can reduce the effect of Project construction activities, noise sensitivities vary based on individual tolerances. Further, the ambient noise level within the property of the sensitive receptor may well be already below the 65 dB standard.

Depending on individual sensitivity, any incremental increase of that ambient noise level could be considered intrusive by the homeowner, church member, or other user of the sensitive receptor. Because there is no satisfactory means to measure the subjective effect of noise, construction noise is considered a significant adverse impact if located near one or more sensitive noise receptors (e.g., a home, hospital, school, church, or other public assembly facility). The impacts from the Project on noise quality would be potentially significant as exceeding the 65 dB level in locations closer to the well pad (Tables 4.12-9 through 4.12-12). Additionally, due to varying ambient noise levels across the Project Area, it is impossible to ensure a predictable increase in ambient noise levels using feasible mitigation measures. Even with all feasible mitigation measures, it is impossible to eliminate all construction noise.~~;~~ *Furthermore, there is no satisfactory means to measure the subjective effect of noise on every individual.* ~~t~~*T*hus, *even with mitigation,* temporary noise impacts are significant and unavoidable.

Permanent Increases (Operations Impacts)

Using the noise levels associated with oil and gas production wells and related accessory activities included in the Project, distances from individual Project-related noise sources to the 50 dB, 55 dB, *60 dB* and ~~60~~ *65* dB contours were calculated using SoundPLAN. As with construction activities, these measurements were taken from the loudest direction of the studied equipment and while the equipment was operated at maximum volume. In addition, the SoundPLAN evaluation used conservative assumptions. The results of the calculations are provided in Table 4.12-13. As with construction noise, at increased distances from a modeled noise source (distances greater than 1,000 feet), the modeled results include tolerance limitations of +/- 5 dB to take into account noise source variables such as atmospheric conditions (including wind speeds and direction), topography, and ground absorption that could cause actual results to vary from modeled results.

Table 4.12-13: Operational Noise Exposure Kern County Oil and Gas Production

	Distance (feet) to Contour			
	Distance (feet) to L_{eq} Contour		Distance (feet) to DNL Contour	
Activity	**50 dB**	**55 dB**	**60 dB**	**65 dB**
Well Production (Electric Power)	180	110	130	80
Well Production (Diesel Power)	580	330	340	210

Source: Brown-Buntin 2015.
Key:
dB = decibels
DNL = average day-night level
L_{eq} = equivalent sound pressure level

At a distance of 130 feet from a well, noise from electric-powered oil and gas wells would attenuate to a level of 60 dB, which is less than 65 dB DNL. However, noise from diesel-powered oil and gas wells would not attenuate to a level of 60 dB ~~DNL~~ until 340 feet from a well (see Table 4.12-

13). Under the current established setback, a residence or church or other sensitive receptor could be located within 150 feet of a well; therefore, there is the potential for a substantial permanent increase in ambient noise levels in excess of the 65 dB standard in the vicinity of sensitive noise receptors and, therefore, impacts could be significant.

Noise levels from the operation of industrial-scale ancillary activities, such as cogeneration plants and water treatment facilities, were not separately evaluated since these facilities currently exist in locations that are not proximate to any sensitive noise receptor (e.g., Tier 1 areas). As with well drilling, typically the loudest source of noise associated with well operation is the power generation equipment. Noise levels from tank batteries, subsurface pipelines, and related smaller-scale industrial activities would be expected to be at or below the noise levels measured for well production activities based on power generation equipment noise as noted in Table 4.12-13.

Larger ancillary facilities are outside the scope of this Project (i.e., no new cogeneration facilities or landfills are included within the scope of the Project), and mitigation measures for such excluded facilities are not proposed.

Flare Noise

WJV Acoustics, Inc., prepared an acoustical analysis to specifically analyze the noise impacts from venting and flaring, which was included as Appendix V-3 of the 2015 FEIR (SREIR Volume 7). As part of the Flare Noise Assessment, noise levels associated with gas flare activities were measured at several locations throughout Kern County (see Table 4.12-14). For each analyzed flare, noise level measurements were taken in multiple directions from the flare to account for variations that occur as a result of localized conditions, such as wind or site-specific shielding. In addition, for each modeled gas flare, the loudest observed measurement was utilized as a basis for modeling potential Project-related noise exposure. As a result, gas flare noise levels disclosed in the Flare Noise Assessment represent a worst-case assessment of gas flare noise exposure.

Table 4.12-14: Gas Flare Noise Exposure

	Distance (feet) to L_{eq} Contour		Distance (feet) to DNL Contour	
Flare	**50 dB**	**55 dB**	**60 dB**	**65 dB**
Hopkins Flare	43	24	27	15
Redbank and Edison	140	80	107	60
Semitropic	185	105	130	73
Shafter[(a)]	4,200	2,400	2,960	1,664
Maricopa	350	200	251	141

Source: 2015 FEIR, Appendix V-3 (SREIR Volume 7)
Note:
[(a)] Shafter flare was operating under anomalous conditions, noise levels provided are not considered typical.
Key:
dB = decibels
DNL = day-night level
L_{eq} = equivalent sound pressure level

As discussed above, the KCGP establishes an exterior noise threshold of 65 dB DNL as measured in outdoor activity areas of sensitive receptors. The Flare Noise Assessment analyzed the flare noise impacts as compared to the County's selected threshold and determined that "compliance with the distances summarized in Table V *[65 dB contour]* should be interpreted to mean that a significant noise impact would not be expected as a result of the project and additional noise mitigation will not be required." *Additionally, contours for noise generated by flares operating under typical conditions are within the contours established for oil and gas well operations generally.*

Traffic Noise

A Traffic Impact Study and Roadway Assessment for the Project was prepared by Ruettgers & Schuler (2015) to analyze potential impacts of the Project and was included as Appendix W of the 2015 FEIR (SREIR Volume 4). Potential Project impacts on existing traffic levels and roadways were determined for both construction and operation of the Project, using the most recently published roadway traffic volumes and Project-related vehicle trip calculations.

The Project would be expected to generate the equivalent of 19,300 trips per day by 2035, which includes worker trips, as well as equipment and material delivery truck trips. These trips would be disbursed to more than 500 roadways within the Project Area, based on historic wellfield production rates.

A doubling of traffic volumes on a roadway would be expected to result in a 3 dB increase in noise generated by traffic, which is equivalent to the human threshold for perceiving a change in the ambient noise level. Based on the Project trip generation calculations and distribution as shown in Section 4.16, Traffic and Transportation, of the 2015 FEIR, the Project would not double the traffic volumes on any affected roadways. Therefore, no significant increase in noise levels would occur along area roadways as a result of the Project.

Ambient Increase

The CEQA Guidelines require that noise impacts be evaluated against the standards developed by the pertinent local agency. As discussed above, because Project activities may occur both inside and outside of the boundaries of the MBGP, the noise effects of the Project will be subject to both an absolute limit of 65 dB and an incremental increase standard of 5 dB. While less than 8% of the Project Area is within the MBGP and 90% of Project activities are anticipated to occur in Tier 1 areas, it is appropriate to analyze the incremental increase caused by Project activities on the existing ambient noise level. When a Project activity is proposed in an area with an ambient noise level under 65 dB, the noise impact of that activity will be considered significant if it will increase the ambient noise by more than 5 dB. If the ambient noise is at or above 65 dB, the Project activity may increase the ambient noise level by no more than 1 dB.

Nevertheless, the 2015 Environmental Noise Assessment identified 18 study sites for the assessment of ambient noise levels within the Project Area. These sites are representative of typical conditions within the Project Area, but they are not comprehensive. It is possible that the ambient noise levels at a particular site within the Project Area could be either lower or higher than the sites sampled for the 2015 Environmental Noise Assessment. While the ambient levels at these sites can disclose the range of Project sound levels which would not result in a significant impact, the actual level for any specific site can only be determined based on an individualized study of that site.

Table 4.12-12 illustrates the application of the 5 dB and 1 dB thresholds based on the range and average of existing ambient noise at various study sites. Ambient noise levels were measured throughout the Project Area, with DNL values ranging from 44.8 dB to 67.8 dB, with an average of 54.7 dB. As indicated in Table 4.12-12 above, based on the site-specific ambient conditions analyzed in the 2015 Environmental Noise Assessment, Project noise levels could range from 48.8 dB to 63.8 dB without creating a significant effect.

Incremental change over ambient level is generally dependent on site-specific measures, but by using the lowest measured ambient noise level from the 2015 Environmental Noise Assessment, a contour can be generated beyond which any increase would be below 5 dB. The lowest measured ambient level was 44.8 dB. Based on the 5 dB incremental standard, Project noise could reach approximately 49 dB (48.8 dB) without resulting in an exceedance. This results in the following screening contours. If these contours are achieved for the respective activity, then the activity will not increase the existing ambient by more than 5 dB.

Table 4.12-14A: Operation Noise Exposure Levels

Activity	***Distance (feet) to 49 dB L_{eq} Contour***
Well Production (Electric Power)	*198*
Well Production (Diesel Power)	*650*

Source: WSP 2020.
Key:
dB = decibel
Leq = equivalent sound pressure level

~~*In the loudest of the study locations, depending on the specific activity, operation activities could be sited from 80 to 210 feet away without creating a significant effect. In the quietest of the study locations, these distances may more than double to 180 to 580 feet, depending on the specific activity. Due to this wide variation, it is impossible to impose a setback distance that would ensure a no more than 5 dB increase across all Project locations. In the absence of site-specific acoustical analyses for each Project activity, there are no feasible mitigation measures that would result in a predictable increase in ambient noise levels.*~~

In addition to the existing ambient conditions, site-specific variables, including topography, atmospheric conditions, ground absorption factors, shielding from existing walls or buildings, noise source height and receiver height, all contribute to the dispersion of sound at a particular location. Therefore, a conservative approach of *mitigation* trigger~~s~~ *distance* for noise reduction mitigation ensures the protection of health and safety from noise impacts for sensitive receptors.

However, ~~where a noise reduction setback can't be achieved~~, *where a sensitive receptor is located within the noise mitigation trigger distance in Table 4.12-12A,* then a Noise Reduction Report that shows the ambient noise level at the time of activity and accounts for these variables can be provided and a noise standard achieved. The noise standard to achieve through the mitigation will provide that the maximum amount of construction noise would result in a no more than 5 dB increase in ambient noise for locations where the ambient level is less than 65 dB or that would result in no more than a 1 dB increase in ambient noise for locations where the ambient is at or above 65 dB.

Oil and gas well operations could thus result in increases in ambient noise levels in excess of the 5 dB threshold in at least some of the Project Area without mitigation.

Summary

The ambient noise level in the areas surrounding oilfields is impacted by many sources, including freeways. Table 4.12-12 shows that average ambient noise levels in representative locations were measured throughout the Project Area, with DNL values ranging from 44.8 to 67.8 dB, with an average of 54.7 dB. For some people who are sensitive to noise, the ambient level is already causing distress, and an increase to 65 dB would increase that concern for those sensitive receptors. The location of most Kern County oil and gas exploration and extraction, however, is centered in large oilfields that are predominately used for oil and oilfield-related services companies and not residential and other sensitive receptor uses. There are areas where Project activities may occur in more urbanizing areas or where scattered residential uses or rural schools could be located. However, as detailed in 1.3.1, History of Local Oil and Gas Permitting, since the implementation of the 2015 FEIR, 9,097 permits have been issued and only 113 permits required a noise analysis and mitigation. No applications were submitted for activities within the mitigation-triggering distance for schools.

Based on the current setback requirements for oil and gas activities in Kern County for residential dwellings and hospitals (150 feet), and places of assembly, including schools and churches (300 feet), well operations using electrical power would comply with the established noise level requirement. Noise from diesel-power generation attenuates to less than the 65 dB standard by a distance of 210 feet from the source, indicating that well operations using diesel power may not comply with the standard near residences and hospitals with a 150-foot setback. Therefore, noise impacts from operational Project activities are potentially significant as to the County's absolute threshold of 65 dB at the property line of the sensitive receptor, and new setbacks have been established for noise and health based on the 2015 FEIR. Additionally, while setbacks and noise attenuation strategies can reduce the effect of Project operation activities, noise sensitivities vary based on individual tolerances. Because there is no satisfactory means to measure the subjective effect of noise, impacts due to operational noise could be significant.

Due to the application of the MBGP to Project activities within its boundaries, the County has determined that Project-related noise should not increase ambient noise levels by more than 5 dB when the existing ambient noise level is below 65 dB or by more than 1 dB when the existing ambient noise level is at or exceeds 65 dB. As explained above, an increase of 1 dB is not readily perceptible and will have no meaningful impact on a sensitive receptor. The evidence shows that this standard is protective of the enjoyment of the sensitive receptor's property and protective of health. *As described in Table 4.12-12B, various noise reduction strategies may help to reduce Project noise.* While setbacks and noise attenuation strategies can reduce the effect of Project operation activities, noise sensitivities vary based on individual tolerances. Further, the ambient noise level within the property of the sensitive receptor may well be already below the 65 dB standard. Depending on individual sensitivity, any incremental increase of that ambient noise level could be considered intrusive by the homeowner, church member, or other user of the sensitive receptor. Since the reaction to audible noise increases and different types of noise is subjective and individual tolerance can vary, the operational impacts would be potentially intrusive even with mitigation. Due to varying ambient noise levels across the Project Area, it is impossible to ensure a predictable increase in ambient noise levels using feasible mitigation measures. Further wells that were permitted by CalGEM before the 2015 implementation of this prior ordinance or wells permitted without the requirements of the 2015 EIR after March 26, 2020 to the present, may not have operational noise reduction in place that could use these setbacks for minor activities for routine maintenance. Permanent noise impacts are therefore potentially significant and unavoidable even with mitigation.

MM 4.12-1 incorporates distances identified in Table ~~4.12-8~~ *4.12-12A* that are necessary to achieve a ~~*65*~~ *49* dB contour line for construction activities. *This contour line is based on the lowest measured ambient level in the Project Area and ensures that if this distance is achieved, no sensitive receptor will experience a greater than 5 dB increase over the existing ambient.* If a sensitive receptor is located within the ~~*setback*~~ *mitigation trigger* distances, then either the well must be moved to achieve that distance or mandatory construction noise measures must be implemented to meet the County's standard. When the ~~*setback*~~ *mitigation trigger* distances cannot be achieved, the applicant must prepare a Site Vicinity Map and an Acoustic Noise Report that requires the evaluation of the site-specific ambient noise levels. In this circumstance, it is feasible to require the site-specific mitigation necessary to reduce Project-related noise to the County's incremental noise standard. This measure therefore not only requires that the applicant implement mitigation to reduce the noise at the property line of the sensitive receptor to 65 dB, but also implement mitigation necessary to reduce the increase in ambient noise levels at the property line to 5 dB or less for areas where the ambient is below 65 dB, or to reduce the increase in ambient noise levels to 1 dB or less at the property line for areas where the ambient is already at or in excess of 65 dB.

Thus, if a sensitive receptor is located within the ~~*65*~~ *49* dB contour line identified in Table ~~*4.12-8*~~ *4.12-12A*, the applicant must submit, as part of the Site Plan Application, a site vicinity map and Acoustic Noise Reduction Report that detail the existing ambient noise level of the sensitive receptor at the property line of that sensitive receptor and the measures required to achieve the standards described above.

The setback in all cases shall be no less than the 210 and 300 feet established in the proposed Zoning Ordinance, and MM 4.12-2 has been clarified to show that.

MM 4.12-1 is proposed for adoption as a complete replacement for the version of MM 4.12-1 adopted as part of the 2015 FEIR. ~~*The noise attenuation setbacks have not changed, but the noise*~~

~~*standard, details of the Noise Reduction Report, and other details regarding implementation have been modified.*~~ Due to usability concerns, a full strike-through of these changes is not provided below, but the version of MM 4.12-1 adopted as part of the 2015 FEIR can be found in the 2015 FEIR (SREIR Volume 3).

MM 4.12-2 has been modified to incorporate a parallel structure to MM 4.12-1 to address incremental increases over ambient level. MM 4.12-2 further incorporates the definition of sensitive receptor to increase clarity and improve implementation of the Ordinance. MM 4.12-2 Operations mandates a minimum 210-foot setback for all sensitive receptors and 300 feet for legally permitted public and private schools. As Table 4.12-14 A details that the use of electric power for well production is in compliance at 198 feet, such operations will be covered by the mandatory 210- or 300-foot-setback. MM 4. 12-2 further states that the processing and approval of a Conditional Use Permit is required for any requests to reduce those mandatory setbacks. That would require a public hearing process and additional environmental review under CEQA. The mitigation distance trigger then becomes operations for a well between 210 and 650 feet using diesel power for well production. The contour line is based on the lowest measured ambient in the Project Area and ensures that if this distance of more than 650 feet using diesel power is achieved, no sensitive receptor will experience a greater than 5 dB increase over the existing ambient. If a sensitive receptor property line is located closer than 640 feet, then either the well must be moved to achieve that standard or mandatory operational noise measures must be implemented to meet the County's standard.

As in MM 4.12-1, if the site is closer than 650 feet and states they will be using diesel power, then the applicant must prepare a Site Vicinity Map and an Acoustic Noise Reduction Report that requires the evaluation of the site-specific ambient noise levels. This measure therefore not only requires that the applicant implement mitigation to reduce the noise at the property line of the sensitive receptor to 65 dB, but also implement mitigation necessary to reduce the increase in ambient noise levels at the property line to 5 dB or less for areas where the ambient is below 65 dB, or to reduce the increase in ambient noise levels to 1 dB or less at the property line for areas where the ambient is already at or in excess of 65 dB.

Both MM 4.1-1 and MM 4.12-2 are proposed for adoption as a complete replacement for the version of MM 4.12-1 and 4.12-2 adopted as part of the 2015 FEIR and circulated with SREIR (August 2020). Due to usability concerns, a full strike-through of these changes is not provided below, but the version of MM 4.12-2 adopted as part of the 2015 FEIR can be found in the 2015 FEIR (SREIR Volume 3).

Setbacks and Mitigation Trigger Distances for Impacts

This SREIR (October 2020) has refined the mitigation for establishing the distances the new oil and gas wells permitted with an Oil and Gas Conformity Review need to be from sensitive receptors and when the distance proposed triggers additional mitigation. For purposes of both the air quality and noise analyses in the 2015 FEIR and SREIR (August 2020 and October 2020), sensitive receptors are defined as single or multi-family dwelling units, places of public assembly (defined to mean a legally permitted place where 100 or more people gather together in a building or structure for purpose of amusement, entertainment or retail sales), churches, institutions, schools, *and hospitals. These uses are generally considered to be more sensitive to air pollution or noise impacts than others due to type of population, the number of people affected, or the type of activity.*

There is a minimum setback from sensitive receptors which is mandatory and cannot be reduced through the ministerial process; 210 feet from single or multi-family dwelling units, places of public assembly (defined to mean a legally permitted place where 100 or more people gather together in a building or structure for purpose of amusement, entertainment or retail sales), churches, institutions, and hospitals and 300 feet from the property line of a legally permitted public or private school.

In addition to this mandatory minimum setback, there are mitigation trigger distances for air impacts from the Health Risk Assessment (HRA) (MM 4.3-5) and noise impacts from construction MM 4.12-1) and operations (MM 4.12-2). For both noise and air impacts, the mitigation measures establish a default screening distance beyond which construction activities will not exceed the thresholds established. If there are sensitive receptors inside the distances specified there is a presumption, based on the studies, that the air quality emissions or noise levels will exceed applicable thresholds. Applicants may only conduct the identified activities inside those distances with mitigation to meet the applicable standards.

For impacts to air quality identified in the HRA for construction if the well is within the mitigation trigger distance then the Applicant must demonstrate to the SJVAPCD that alternative measures achieve a level of risk less than the threshold level of risk. The implementation requires the applicant to prepare a risk assessment showing the impacts and how on site mitigation will reduce those impacts to the threshold of risk established by the SJVAPCD. Such measures include, but are not limited to; placing engines away from sensitive receptors; utilizing directional drilling to locate the rig farther from sensitive receptors; using late-model low-emission diesel products, alternative cleaner fuels, retrofit technology, add-on devices, and other emission reducing equipment; utilizing electricity line power when available; limiting idling to 15 minutes; using automatic rigs; and written confirmation from the occupants of the sensitive receptor of their voluntary, temporary relocation or use restrictions during a defined construction period. If the Applicant cannot achieve the setback distances in MM 4.3-5 or cannot achieve the required risk levels through reduction measures, then it is not eligible for a ministerial permit.

Similarly for noise impacts during construction if the well is within the mitigation trigger distance then the Applicant must submit an Acoustic Noise Reduction Report based on site-specific measurements to achieve the Noise Standard detailed in the SREIR and MM 4.12-1. Noise reduction measures include placement of a temporary sound attenuation wall; construction of a temporary berm; specific orientation of the drilling equipment on the well site and modification of the equipment to reduce noise impacts; implementation of detailed sounds reduction technology or practices to reduce the noise impact at the sensitive receptor's property line; or written confirmation from the occupants of the sensitive receptor of their voluntary, temporary relocation or use restrictions during a defined construction period.

For the final stage of implementation of the Oil and Gas Conformity Review permit, the 2015 FEIR and SREIR (August 2020 and October 2020) analyzed the air quality and noise impacts from operational activities.

For air quality, the Multi-Well HRA found that the health risk with this conservative multi-well scenario would be 9.3 in one million, below the SJVAPCD threshold of 20 in 1 million. The mandatory minimum setback of 210 feet is therefore fully protective of health risk impacts for operations along with the mitigation for criteria pollutants under the Kern OG-ERA.

Operational noise is addressed by MM 4.12-2, which requires that if a new well is located between 210 and 650 feet from the property line of the nearest sensitive receptor or between 300 and 650 feet of a school and utilizing a diesel engine for well production, then an Acoustic Noise Reduction Report and appropriately sized permanent block wall or barrier is required to be installed. The presumption is that the incremental increases to the ambient noise level will exceed the Noise Standard with the use of the diesel engine. The applicant may elect to use electricity for power, either through a hard connection or a solar/with battery backup and fully mitigate the operational noise impacts. Electricity- powered production meets the standard at a distance of 198 feet and with the mandatory minimum distance of 210 feet, the impacts are mitigated for this ministerial permit.

For consistency in implementation, MM 4. 3-5, MM 4.12-1, and MM 4-12 -2 all require the Oil and Gas Conformity Review Site Plan Application to provide a Site Vicinity Figure showing the location of any sensitive receptors within 4,000 feet of the site. For any permit that intends to obtain a CalGEM permit for exploratory drilling, the Site Vicinity Figure shall show the location of any sensitive receptors within 8,000 feet of the site. Each mitigation has detailed implementation requirements and Mitigation Trigger Distances. Table 4.12-15 compiles all the distance triggers and includes the 210- and 300-foot setback.

Table 4.12-15: Compilation of Mitigation Trigger Distances and Mandatory Setbacks– Sensitive Receptors

<table>
<tr><th></th><th colspan="3">Mitigation Trigger Distances Effective During Construction</th><th colspan="3">Mitigation Trigger Distances (MM 4.12-2) Operation</th></tr>
<tr><th rowspan="2">Well Depth (Feet)</th><th rowspan="2">Mitigation Measure 4.3-5 (Feet) Air</th><th rowspan="2" colspan="2">Mitigation Measure 4.12-1 (Feet) Noise</th><th colspan="2">Default Distance Effective During Operations (Feet) Noise</th><th rowspan="2">Mandatory Minimum Setback (Feet)</th></tr>
<tr><th>Electric Powered</th><th>Diesel Powered</th></tr>
<tr><td colspan="7">Western Subarea</td></tr>
<tr><td rowspan="5">10,000</td><td rowspan="5">367</td><td>Drilling (Well Advancement)</td><td>3,900</td><td rowspan="5">198</td><td rowspan="5">650</td><td rowspan="5">210
other receptors

300 – School</td></tr>
<tr><td>Drilling (Pull Out of Well/Borehole)</td><td>2,350</td></tr>
<tr><td>Large-Scale Exploratory Drilling</td><td>7,900</td></tr>
<tr><td>Well Workover</td><td>2,355</td></tr>
<tr><td>Hydraulic Fracturing</td><td>2,965</td></tr>
<tr><td rowspan="5">5,000</td><td rowspan="5">116</td><td>Drilling (Well Advancement)</td><td>3,900</td><td rowspan="5">198</td><td rowspan="5">650</td><td rowspan="5">210
other receptors

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	Mitigation Trigger Distances Effective During Construction			Mitigation Trigger Distances (MM 4.12-2) Operation		
Well Depth (Feet)	Mitigation Measure 4.3-5 (Feet) Air	Mitigation Measure 4.12-1 (Feet) Noise		Default Distance Effective During Operations (Feet) Noise: Electric Powered	Default Distance Effective During Operations (Feet) Noise: Diesel Powered	Mandatory Minimum Setback (Feet)
		Fracturing				
2,000	NA	Drilling (Well Advancement)	3,900	198	650	210 other receptors 300 – School
		Drilling (Pull Out of Well/Borehole)	2,350			
		Large-Scale Exploratory Drilling	7,900			
		Well Workover	2,355			
		Hydraulic Fracturing	2,965			
Central Subarea						
10,000	367	Drilling (Well Advancement)	3,900	198	650	210 other receptors 300 – School
		Drilling (Pull Out of Well/Borehole)	2,350			
		Large-Scale Exploratory Drilling	7,900			
		Well Workover	2,355			

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		Hydraulic Fracturing	2,965			
5,000	116	Drilling (Well Advancement)	3,900	198	650	210 other receptors 300 – School
		Drilling (Pull Out of Well/Borehole)	2,350			
		Large-Scale Exploratory Drilling	7,900			
		Well Workover	2,355			
		Hydraulic Fracturing	2,965			
2,000	NA	Drilling (Well Advancement)	3,900	198	650	210 other receptors 300 – School
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<tr><td>Hydraulic Fracturing</td><td>2,965</td><td></td><td></td></tr>
<tr><td colspan="7">Eastern Subarea</td></tr>
<tr><td rowspan="5">10,000</td><td rowspan="5">296</td><td>Drilling (Well Advancement)</td><td>3,900</td><td rowspan="5">198</td><td rowspan="5">650</td><td rowspan="5">210
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Table 4.12-15: Compilation of Mitigation Trigger Distances and Mandatory Setbacks– Sensitive Receptors

	Mitigation Trigger Distances Effective During Construction			Mitigation Trigger Distances (MM 4.12-2) Operation		
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5,000	NA	Drilling (Well Advancement)	3,900	198	650	210 other receptors 300 – School
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		Drilling (Pull Out of Well/Borehole)	2,350			
		Large-Scale Exploratory Drilling	7,900			
		Well Workover	2,355			
		Hydraulic Fracturing	2,965			

~~MM 4.12 -2 has been modified to increase clarity and improve implementation of the Ordinance as follows.~~

~~MM 4.12-1~~ *~~The Site Plan Application shall include a Site Vicinity Figure showing the location of any sensitive receptor(s) at or within the distances listed in the construction noise setbacks table, as shown below, of the construction site (potential impact area) for the proposed new well or ancillary facility or equipment (excluding pipelines). This Site Vicinity Figure need not be prepared for Tier 1 areas unless a sensitive receptor is located within 3,270 feet of a construction site inside the Tier 1 area.~~*

~~The following are setbacks distances for the specific activities for determination of the requirements of the Site Vicinity Figure and noise analysis.~~

~~Activity~~	*~~Setback Distance (feet)~~*
~~Drilling (Well Advancement)~~	*~~1,550~~*
~~Drilling (Pull Out of Well /Borehole)~~	*~~820~~*
~~Large-Scale Exploratory Drilling~~[1]	*~~3,270~~*
~~Well Workover~~	*~~930~~*
~~Hydraulic Fracturing~~	*~~1,090~~*

~~The Site Plan Application Vicinity Figure and Noise Study shall fully comply with the following requirements:~~

~~a. The Site Vicinity Figure shall have the following dimensions and detailed notes that include the following, based on the specific details of the submitted noise analysis.~~

~~i. Clearly marked distances from the construction location on the well site to all sensitive receptors within the potential impact area. If the location is a neighborhood group of sensitive receptors, then the distance shall be shown to the nearest receptor.~~

~~ii. Notes showing the ambient outdoor noise level at the property line of all identified sensitive receptors.~~

~~iii. Specific details of the required mitigation for noise reduction to the noise standard at the sensitive receptor's property line.~~

~~iv. If there are no sensitive receptors within this potential impact area, then no construction mitigation measures shall be required and a statement placed on the application submittal.~~

~~b. If there are sensitive receptors, defined as a single or multi-family dwelling unit, place of public assembly, institutions, school or hospital, within the~~

~~*potential impact area, then a noise study by an acoustical expert must be submitted that has the following site-specific information.*~~

~~*The standard for reduction shall be that at the property line of the sensitive receptor the noise level shall not exceed 65 dBA, any ambient levels in excess of 65 dBA or more than 1 dBA higher than the ambient noise levels if in excess of 65 dBA.*~~

~~*i. The ambient outdoor noise level at the property line of the sensitive receptor.*~~

~~*ii. The noise level of the construction equipment before mitigation.*~~

~~*iii. The noise level of the construction activities after selected mitigation.*~~

~~*iv. The noise contour levels of the activities after selected mitigation.*~~

~~*v. Details of the noise attenuation measures, as determined by an acoustical expert, to reduce the noise impacts at the property line of the sensitive receptor to the standard. The noise attenuation shall be one or more of the following methods with specific details for implementation. Multiple options are not permitted to be submitted.*~~

~~*A. Placement of a temporary sound attenuation wall(s) on property controlled by the applicant that shall be placed the optimal distance to the sensitive receptor property line to reduce the noise impact to the standard.*~~

~~*B. Construction of a temporary berm on property controlled by the applicant that shall be placed at the optimal distance to the sensitive receptor's property line to reduce the noise impact to the standard.*~~

~~*C. Specific orientation of the drilling equipment on the well site and modification of equipment to reduce noise impacts.*~~

~~*D. Implementation of detailed sound reduction technology or practices to reduce the noise impact at the sensitive receptor's property line to the standard.*~~

~~*E. Written confirmation from the occupants of the sensitive receptors of their voluntary, temporary relocation during a defined construction period*~~

~~***MM 4.12-2 Operation***~~

~~*New oil and gas wells shall be a minimum of 210 feet from the closest sensitive receptor (single or multi-family dwelling unit, place of public assembly (a legally permitted place where 100 or more people gather together in a building, or structure, for the purpose of amusement, entertainment, or retail sales), churches, institutions, schools, or hospitals). Geophysical testing methods using vibroseis vehicles to generate sound waves shall be a minimum of 150 feet from the closest*~~

~~*occupied building, water well, sewer system, and septic tank. Geophysical testing methods using shotholes that employ explosives shall be a minimum of 300 feet from the closest occupied building, water well, sewer system and septic tank, and shall be in full compliance with all laws governing explosives.*~~

Mitigation Measures

MM 4.12-1 Construction

The Site Plan Application for an Oil and Gas Conformity Review shall include a Site Vicinity Figure showing the location of any sensitive receptor(s) within 4,000 feet of the construction site (potential impact area) for the proposed new well or other ancillary facility or equipment (excluding pipelines). For any permit intending to process an Exploratory Well Permit with CalGEM, the Site Vicinity Figure shall show the locations of any sensitive receptors within 8,000 feet of the construction site. A sensitive receptor is defined as a single or multi-family dwelling unit, place of public assembly (a legally permitted place where 100 or more people gather together in a building or structure for the purpose of amusement, entertainment or retail sales), church, institution, school, or hospital.

The site plan shall comply with the following details:

1. Determination of Distance

a. If there are no sensitive receptors within this potential impact area, then no construction mitigation measures shall be required and the statement shall be placed as a note on the site plan.

b. The well site and nearest property line of a sensitive receptor shall be shown on the site plan using both feet and coordinates. If there is a neighborhood of sensitive receptors, then the site plan shall identify the nearest group. If there are sensitive receptors within the potential impact area, then additional information must be provided showing the distance in feet and coordinates from the closest edge of the well pad to the property line of the nearest sensitive receptor.

c. Table 1, below, shall be used to identify the mitigation trigger distance for the activity and a note placed on the site plan identifying the specific listed construction activity and mitigation trigger distance.

d. If the nearest sensitive receptor property line is closer than the distance on Table 1, Construction Noise Mitigation Trigger Distance, then noise reduction measures to reduce impacts to the following Noise Standards shall be implemented:

Noise Standards

- *For locations where the ambient level is below 65 dB, noise levels from construction activities may not increase the existing ambient level at the* *property line of the sensitive receptor by more than 5dB and may not exceed 65 dB at the property line of the sensitive receptor;*

- *For locations where the ambient level is at or in excess of 65 dB, noise levels from construction activities may not increase the existing ambient level at the property line of the sensitive receptor by more than 1 dB.*

Table 1: **Construction Noise *Mitigation Trigger Distances***

Activity	*Mitigation Trigger Distance (feet) For distance to closest sensitive receptor*
Drilling (Well Advancement)	*3,900*
Drilling (Pull Out of Well/Borehole)	*2,350*
Large-Scale Exploratory Drilling[(a)]	*7,900*
Well Workover	*2,355*
Hydraulic Fracturing	*2,965*

Note: [(a)] Kenai Drill Rig #7

e. *If a sensitive receptor is located within the noise mitigation trigger distances identified in Table 1, the activity location must either be relocated to achieve the distance as a setback, or an Acoustic Noise Reduction Report with mandatory noise reduction measures shall be prepared and submitted to show how to achieve the Noise Standard. The mitigation trigger distances and ambient noise levels are measured from the legal parcel property line facing the well pad site of the closest sensitive receptor.*

2. Acoustic Noise Reduction Report

a. An Acoustic Noise Reduction Report completed by a qualified professional shall be provided in conjunction with the application if the identified mitigation trigger distance will not be met. The report and submitted site vicinity map shall include all dimensions and detailed notes, based on the Acoustic Noise Reduction Report detailed in this measure.

b. Clearly marked distances in feet and with coordinates from the construction location on the well site to the nearest sensitive receptors both exterior wall of the receptor and the property line within the potential impact area.

c. Notes showing the average day-night level (DNL or L_{dn}) of ambient outdoor noise level at the proposed well location and at the property line of the nearest identified sensitive receptors that face the drill site over a 24-hour period.

d. Specific details from the Acoustic Noise Reduction Report specifying the level of project activity noise at the property line of the sensitive receptor allowed under the Noise Standard and the projected level of noise from the Project *activity before implementation of noise reduction measures and after implementation of noise reduction measures.*

e. *The report shall identify and include the specific noise reduction method or methods that will be implemented and shall not include options for compliance. Any changes to the selected method or methods of compliance after approval will require submission of an amended Acoustic Noise Reduction Report reflecting the new selection.*

1 *Placement of a temporary sound attenuation wall(s) on property controlled by the applicant or with written permission from the property owner in compliance with Chapter 19.98.*

2. *Construction of a temporary berm on property controlled by the applicant or with written permission from the property owner in compliance with Chapter 19.98.*

3. *Specific orientation of the drilling equipment on the well site and modification of equipment to reduce noise impacts.*

4. *Implementation of other detailed sound reduction technologies or practices with evidence from the qualified professional of the reductions achieved.*

5. *Written confirmation from the occupants of the sensitive receptor(s) of their voluntary, temporary relocation or business restrictions during a defined construction period.*

3. *Monitoring*

For the duration of the construction the following measurements shall be submitted to the Kern County Planning and Natural Resources Department at the required intervals. The measurements shall show achievement of the stated average day-night noise level stated on the Site Plan. If the measurement does not show the level is achieved, additional measures must be proposed and installed to prevent a stop work notice. Failure to submit within one business day after taking the required measurements will result in a stop work notice.

a. *24 hours after completion of all noise attenuation measures and commencement of drilling or rework activities, the applicant shall take a measurement at the ambient level at the property line of the identified, nearest sensitive receptor.*

b. *Every 14 days after commencement of activities, the applicant shall take a measurement at the ambient level at the property line of the identified, nearest sensitive receptor until completion of construction activities.*

c. *All installed noise attenuation measures shall be maintained throughout all construction phase activities.*

MM 4.12-2 **Operation**

1. ***Mandatory Setbacks***

The following are distances for a setback that can only be reduced by the processing and approval of a Conditional Use Permit with further environmental review under CEQA.

a. *New oil and gas wells shall be a minimum of two hundred and ten (210 feet) from the closest sensitive receptor for the following uses: single or multi-family dwelling unit, place of public assembly (a legally permitted place where 100 or more people gather together in a building, or structure, for the purpose of amusement, entertainment, or retail sales), church, institution-or hospital.*

b. *New oil and gas wells shall be a minimum of three hundred (300) feet of the legal parcel property line that contains a permitted public or private school. A single family or multi-family dwelling unit that may have home schooling activities shall use the single family dwelling unit distance.*

c. *Geophysical testing methods using vibroseis vehicles to generate sound waves shall be a minimum of one hundred and fifty (150) feet from the closest occupied building, water well, sewer system, and septic tank. Geophysical testing methods using shotholes that employ explosives shall be a minimum of three hundred (300) feet from the closest occupied building, water well, sewer system, and septic tank and shall be in full compliance with all laws governing explosives.*

2. ***Site Vicinity Figure***

The Site Plan Application for an Oil and Gas Conformity Review shall include a Site Vicinity Figure showing the location of any sensitive receptor(s) within 4,000 feet of the construction site (potential impact area) for the proposed new well or other ancillary facility or equipment (excluding pipelines). A sensitive receptor is defined as a single or multi-family dwelling unit, place of public assembly (a legally permitted place where 100 or more people gather together in a building or structure for the purpose of amusement, entertainment or retail sales), church, institution, school, or hospital.

The site plan shall comply with the following details:

3. ***Determination of Distance***

a. *If there are no sensitive receptors within this potential impact area, then no permanent operational noise mitigation measures shall be required and the statement shall be placed as a note on the site plan.*

b. *If the well site is between two hundred and ten (210) feet and six hundred and fifty (650) feet of the well pad and nearest property line of a sensitive receptor other than a school, then it shall be shown on the site plan. If the well site is between three hundred (300) feet and six hundred and fifty (650) feet of the property line of a legally permitted public or private school, then it shall be* *shown on the site plan. If there is a neighborhood of sensitive receptors, then the site plan shall identify the nearest group.*

c. *Location of a well between two hundred and ten (210) feet and six hundred and fifty (650) feet of the well pad and nearest property line of a sensitive receptor shall require either details of the use of electric power for the well production which will mitigate the noise or the submittal of an Acoustic Noise Reduction Report if diesel power is used for the well production.*

4. *Acoustic Noise Reduction Report*

a. *An Acoustic Noise Reduction Report completed by a qualified professional shall be provided in conjunction with the application for any well sited between two hundred and ten (210) feet and six hundred and fifty feet (650) feet of the well pad and nearest property line of a sensitive receptor that will use diesel power for the well production. The report and submitted site vicinity map shall include all dimensions and detailed notes, based on the Acoustic Noise Reduction Report detailed in this mitigation measure. The report shall be based on the following noise standard'*

b. *Noise Standards*

- *For locations where the ambient level is below 65 dB, noise levels from operation of the well may not increase the existing ambient level at the property line of the sensitive receptor by more than 5dB and may not exceed 65 dB at the property line of the sensitive receptor.*

- *For locations where the ambient level is at or in excess of 65 dB, noise levels from operation of the well may not increase the existing ambient level at the property line of the sensitive receptor by more than 1 dB.*

c. *The site plan shall include notes showing the average day-night level (DNL or L_{dn}) of ambient outdoor noise level at the proposed well location and at the property line of the nearest identified sensitive receptors that face the drill site over a 24-hour period.*

d. *Specific details from the Acoustic Noise Reduction Report specifying the level of operational noise at the property line of the sensitive receptor allowed under the Noise Standard and the projected level of noise from the operational noise before implementation of noise reduction measures and after implementation of noise reduction measures.*

e. *If a permanent wall or solid barrier type material is utilized as a noise reduction measure, the holder of the Oil and Gas Conformity permit is responsible for obtaining any and all building permits required, maintenance and graffiti removal for the life of the oil well or group of wells being mitigated. No landscaping is required for the wall. The wall* *shall be removed when the well is abandoned and plugged. Requests to delete these requirements will require the processing and approval of a Conditional Use Permit.*

Level of Significance After Mitigation

Impacts would be significant and unavoidable.

Impact 4.12-2: Exposure of Persons to, or Generate, Excessive Ground-borne Vibration or Ground-borne Noise Levels

The analysis of the potential of the Project to expose persons to or generate excessive ground-borne vibration or ground-borne noise levels was assessed in the 2015 FEIR (SREIR Volume 3) and in Appendix V-2 of the 2015 FEIR (SREIR Volume 5).

Mitigation Measures

No mitigation measures are required.

Level of Significance

Impacts would be less than significant.

Impact 4.12-3: For a Project Located Within the Vicinity of a Private Airstrip or an Airport Land Use Plan or, Where Such a Plan Has Not Been Adopted, Within Two Miles of a Public Airport or Public Use Airport, Would the Project Expose People Residing or Working in the Project Area to Excessive Noise Levels.

The analysis of the potential of the Project to expose people residing or working in the Project Area to excessive noise levels was assessed in the 2015 FEIR (SREIR Volume 3). The following mitigation measures from the 2015 FEIR continue to be required:

Mitigation Measures

Implement MM 4.12-1 and MM 4.12-2, as described above.

Level of Significance After Mitigation

Impacts would be significant and unavoidable.

4.12.5 Cumulative Setting, Impacts, and Mitigation Measures

Cumulative Setting

The geographic scope for cumulative impacts on noise receptors is the Project Area. Because noise can only be heard within a specific distance of a specific source, the cumulative impact analysis considers the combined noise impacts of the Project with nearby related projects.

The regional plans and projections evaluated in this cumulative analysis are described in Section 3.7 of Chapter 3, Project Description of this SREIR. Implementation of these plans and any projects associated with these plans would be required to comply with the goals, policies, and implementation measures of applicable federal and local laws and land use standards imposed by the respective jurisdictions within which each related project is located. This includes appropriate environmental review, in compliance with the requirements of CEQA and/or the National Environmental Policy Act. Should potential noise impacts be identified, appropriate mitigation would be prescribed.

Impact 4.12-4: Cumulative Impact on Noise Receptors

Since oil and gas activities could occur anywhere in the Project Area, the combined noise levels from the Project and existing or reasonably foreseeable projects depend on the proximity of oil and gas activities to other noise sources at a specific location. Noise generated from construction of certain types of wells authorized under the Project, conservatively assuming use of the largest exploratory deep drilling rig (Kenai Rig), could be in excess of 65 dB ~~CNEL~~ up to 3,270 feet from a construction site and up to 210 feet from a diesel-powered operating well. Therefore, significant noise impacts would occur if there are sensitive noise receptors within 3,270 feet of the construction of a well and 210 feet of an operating diesel-powered well. *Similarly, conservatively assuming use of the largest exploratory deep drilling rig (Kenai Rig), noise generated from the construction of the types of wells authorized by the Project could result in increases of more than 5 dB over the existing ambient at 7,900 feet from a construction site and 650 feet from an operating diesel-powered well.* Other projects with construction or operations occurring concurrently with construction or operations of a well would also contribute to noise levels experienced by nearby sensitive noise receptors.

Projects associated with the aforementioned plans would have to comply with the Kern County Noise Ordinance and/or the Noise Element of the KCGP and, therefore, would have to ensure noise levels did not exceed standards. For example, the Kern Council of Governments (COG) 2014 Regional Transportation Plan for Kern County Final Program Environmental Impact Report provides numerous measures to address transportation-related noise.

Oil and gas activities subject to project authorization would have to implement MM 4.12-1 if there are sensitive receptors within the specified distance of a well to ensure that the noise levels do not exceed 65 dB at the property line of the nearest sensitive receptor or result in a significant increase in existing ambient noise levels, as described above. Cumulatively significant noise impacts could occur even if noise levels associated with oil and gas activities are under 65 dB, depending on the location of another nearby project, its noise levels, the distance to a sensitive noise receptor, and the sensitivity of the users of the sensitive receptor to changes in ambient levels. *Oil and gas activities subject to project authorization would have to implement MM 4.12-1 and MM 4.12-2 if there are sensitive receptors within the specified distance of a well to ensure that the noise levels do not exceed 65 dB at the property line of the nearest sensitive receptor or result in a significant increase in existing ambient noise levels, as described above. Cumulatively significant noise impacts could occur even if noise levels associated with oil and gas activities are under 65 dB and do not result in a significant increase in existing ambient levels, depending on the location of* *another nearby project, its noise levels, the distance to a sensitive noise receptor, and the sensitivity of the users of the sensitive receptor to changes in ambient levels.*

Mitigation Measures

Implement MM 4.12-1 and MM 4.12-2, as described above.

Level of Significance After Mitigation

Impacts would be significant and unavoidable.

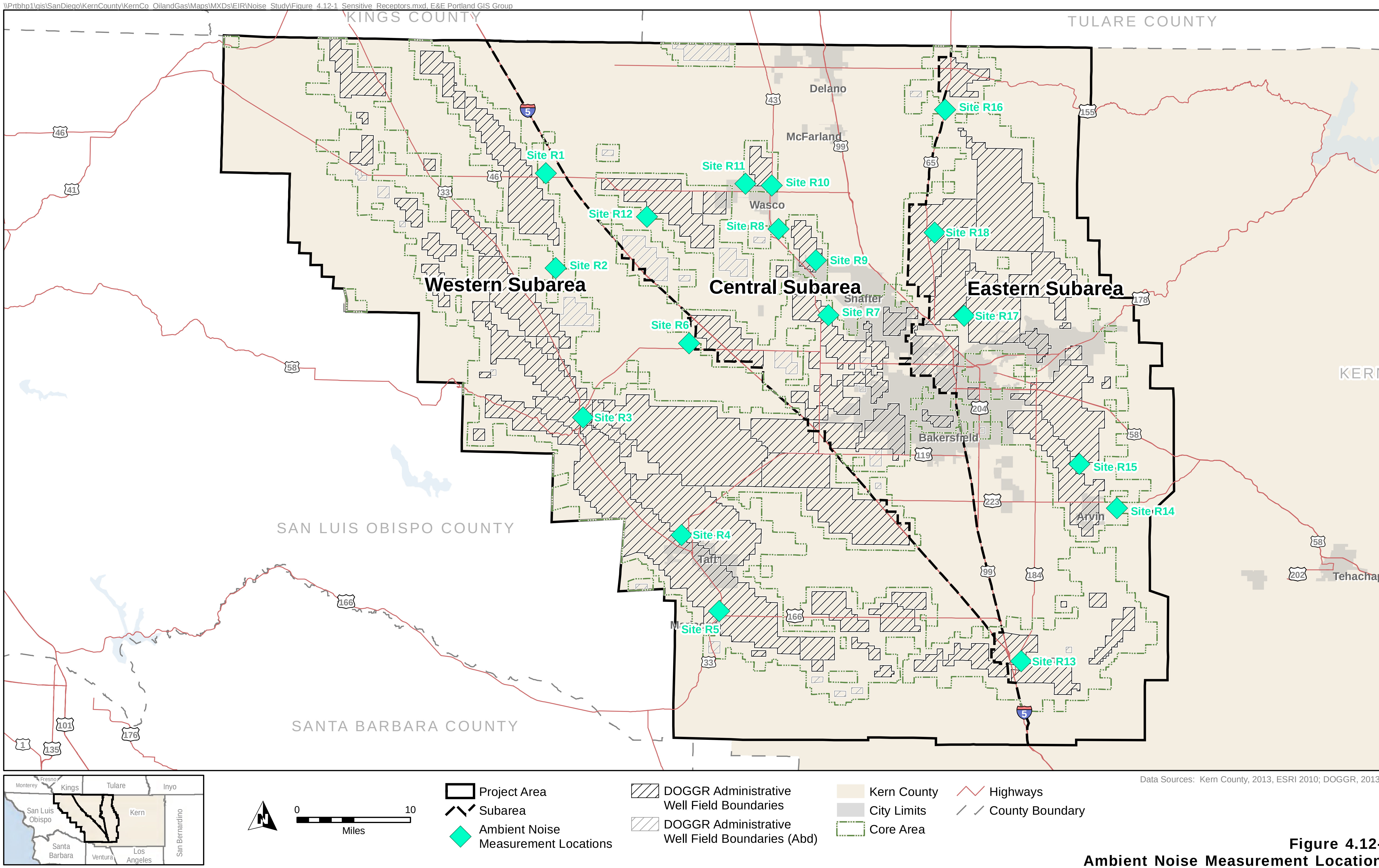

Figure 4.12-1
Ambient Noise Measurement Locations

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Section 4.17

Utilities and Service Systems

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Section 4.17
Utilities and Service Systems

4.17.1 Introduction

This section of the Supplemental Recirculated Environmental Impact Report *(October 2020)* (SREIR) describes the affected environment and regulatory setting for utilities and service systems in relation to water supply informed in part by the Supplemental Water Supply Baseline Technical Report (2020) (see Appendix D) and the groundwater and Sustainable Groundwater Management Act (SGMA) planning information presented in Section 4.9, Hydrology and Water Quality, in this SREIR. This section also describes the impacts to utilities and service systems in relation to groundwater supply and the implementation of the SGMA that would result from implementation of the Amendment to Chapter 19.98 (Oil and Gas Production) and related ordinance amendments to the Kern County Zoning Ordinance, and future development of oil and gas resources pursuant to the Amended Ordinance (Project), and mitigation measures that would reduce these impacts, if necessary. *Except where specifically noted, all underlined and italicized text indicates additions, and italicized strikethrough text indicates deletions from the SREIR (August 2020). Non-italicized underlined and strikethrough text is the same as in the SREIR (August 2020).*

4.17.2 Environmental Setting

Kern County is California's third largest county, encompassing 8,202 square miles at the southern end of the Central Valley. The 3,700-square-mile Project Area is predominantly located in the western portion of the County in the San Joaquin Valley bounded by Kings and Tulare Counties to the north, Santa Barbara and San Luis Obispo Counties to the west, the Tehachapi Mountains and the Sierra Nevada Mountains to the east, and the northern boundary of the Los Padres National Forest to the south.

Kern County is located within the Inland District of the California Geologic Energy Management Division (CalGEM) of the state Department of Conservation. Effective January 1, 2020, the State Division of Oil, Gas and Geothermal Resources (DOGGR) was replaced by CalGEM (Assembly Bill [AB] 1057). Except where noted, references to DOGGR prior to the effective date for CalGEM are retained, but CalGEM is the state's primary regulatory entity for oil and gas activity. The valley floor area of the County and the lower elevations of the surrounding mountain ranges contain numerous deposits of oil and gas resources, a major economic resource for the County. Five of the state's most productive natural gas fields are located in Kern County.

Kern County accounts for approximately 80 percent of total California oil and gas production, and remains one of the largest oil and gas producing counties in the United States. Six of 10 largest property taxpayers in the County are oil and gas companies, and the industry generates approximately $925 million in state and local tax revenues and $1.6 billion in labor income per year. Oil and gas companies directly employ 14,213 people and indirectly generate 9,687 jobs in Kern County (Cox 2020). The oil and gas industry experienced a sharp decline from 2014 to 2016 as the price per barrel of oil, which is used by the County for oil and gas property tax assessments, fell from $101 to $35. The total assessed value of property in the County fell by over $12 billion from 2014 to 2016. In fiscal year 2016–2017, the County experienced a budget deficit of $44.5 million and declared a fiscal emergency. By 2019, oil prices recovered to about $55 per barrel, and the County was able to retire most of the 2016–2017 deficit. In September 2019, the County adopted a budget for 2019–2020 and declared an end to the four-year fiscal emergency (Kern County 2020).

Oil and gas employment and tax revenues in the County, and the County's fiscal condition, were subsequently impacted by several factors. In late 2019, as DOGGR was being reorganized into CalGEM and the state began focusing on a new 2045 energy "carbon neutrality" executive order issued by former Governor Jerry Brown, state regulators publicly indicated that oil and gas activity in California would be discontinued, including in Kern County. The state's position on the oil and gas industry prompted a meeting between the County Board of Supervisors and state regulators attended by over 1,000 members of the public in January 2020. The meeting discussed the state's permitting slowdown and oilfield activity limits, as well as reports that state policies were causing employment losses in the County. After discussions with state officials, the Board unanimously voted to conduct a study evaluating the impacts of the state's actions on the County's economy and budget. The Board also authorized two Supervisors to form a coalition to meet with state officials in Sacramento and explain the effects of California's oil policies on the County (Cox 2020).

In late 2019 and early 2020, global oil prices began sharply falling in response to excess supply conditions worldwide. By early March 2020, oil prices were about $40 per barrel and approaching the levels that were associated with the County's fiscal emergency in 2016–2017. Oil prices fell further due to the global economic disruptions caused by the coronavirus. On April 20, 2020 oil price futures fell to more than minus -$37 per barrel, the lowest level in history. The next day oil prices were $12 per barrel (Kasler 2020). In June 2020 oil prices generally ranged around $40 per barrel but remained substantially below the levels when the 2019–2020 budget was adopted.

The coronavirus also resulted in an unprecedented rapid and large increase in County unemployment. In June 2020, the State Employment Development Department indicated that the County's unemployment rate for April 2020 was 18.6 percent and that 69,800 people of a total County workforce of 375,800 individuals were unemployed, a greater than 300 percent increase since December 2019 (EDD 2020). In June 2020 published reports indicated that the County's budgetary challenges due to declining economic activity and reduced tax revenues associated with the declining oil and gas sector and the coronavirus could be as severe as or more difficult than the 2016–2017 conditions that triggered the County's four-year fiscal emergency (Bell 2020).

Water Supply and Demand

An analysis of the Project Area's water supply and demand, including for oil and gas exploration and production activities, was prepared by the Applicant's consultant, Kennedy/Jenks Consultants (Kennedy/Jenks) and independently reviewed by the County. The analysis is attached as Appendix T-1 to the 2015 FEIR and utilizes the Water Supply Assessment (WSA) criteria in California Water Code Sections 10910 et seq., including an analysis of Project Area water supply and demand under current and projected future conditions in normal or average single dry and multiple dry years and information in the Tulare Lake Basin Portion of Kern County Integrated Regional Water Management Plan (IRWMP), Final Update, prepared by Kennedy/Jenks and approved by the Kern County Water Agency in 2011. The IRWMP provides a cooperative regional framework, implementation plan, and context for managing water resources, and was developed with the participation of a wide range of water agencies, town councils, regulatory, environmental, agricultural, tribal, and land use planning entities in the Kern County region, including the Project Area (Kennedy/Jenks 2011).

As discussed in Section 3.1, Project Overview, of this SREIR, the Appellate Court directed that the water supply baseline for the Project be updated to include and consider new information available from the implementation of the SGMA in the Project Area since the 2015 FEIR was certified. As discussed in more detail below, in Section 4.9, Hydrology and Water Quality, and in Appendix D of this SREIR, the Kern County Subbasin (KCS) underlies the substantial majority of the Project area, and 11 GSAs, five GSPs, and 15 management area plans, all subject to a Coordination Agreement, have been adopted for the KCS. GSAs and GSPs have also been formed and adopted for small portions of other subbasins and basins subject to the SGMA in the Project Area that are primarily located outside the County. In 2016, a portion of the KCS located to the south of the White Wolf Fault was redesignated as a separate subbasin, and a GSA has been formed for this area. A GSP for the new subbasin is required by the end of January, 2022.

Groundwater (Section 4.9, Hydrology and Water Quality) and water supply (Section 4.17, Utilities and Service Systems) baseline conditions and potential Project impacts addressed in this SREIR are described for the Project Area as a whole and for three subareas: the western, central, and eastern portions of the Project Area. This analytical framework reflects both the hydrogeology of the Project Area and the comprehensive, basin-wide sustainable groundwater planning solutions required to comply with the SGMA. As described in Section 3.2.2, "Project Area, the Eastern Subarea encompasses the Sierra Nevada foothills, which have generally higher groundwater quality and receive more recharge from adjacent watershed runoff than other locations. The hydrogeology of the Central Subarea is dominated by the Central Valley plain and agricultural land uses where a small percentage of potential Project oil and gas activity would occur. The Western Subarea includes the coastal range that forms the western edge of the Central Valley, with significantly lower groundwater quality and less surface runoff.

To update the water supply baseline, each GSP and management area plan adopted for any portion of the Project Area was reviewed to identify the extent to which oil and gas operations were identified as a significant factor affecting the achievement of SGMA objectives for applicable subbasins and basins. As discussed in more detail in Section 4.9, Hydrology and Water Quality, the SGMA requires that each designated basin and subbasin subject to multiple GSPs or management area plans be managed under a common set of assumptions and objectives, including a water budget extending over a 50-year planning and implementation horizon. The KCS water budget is discussed in more detail below. Each GSP and management area plan in the KCS, and other GSPs adopted in the Project Area, provides information about potential oil and gas water supply impacts within discrete locations throughout the Project Area and in certain subareas where local water management agencies have developed specialized expertise and information concerning local conditions. Most of the KCS GSPs and management area plans include 50-year *water supply and demand projections for applicable plan areas that, as required by the SGMA, are based on the KCS Coordination Agreement water budget. The purpose of this analysis was to determine whether any GSP or management area plan in the Project Area provided new information suggesting that that oil and gas activities would adversely affect anticipated water supplies, water quality, subsidence, and other SGMA requirements in any portion of the Project Area or one or more subareas to a greater extent than was considered in the 2015 FEIR.*

As summarized below, and in Appendix D and Section 4.9, Hydrology and Water Quality, none of the adopted GSPs and management areas plans within the Project Area identify oil and gas operations as a significant factor affecting the achievement of any of the SGMA objectives. None of the 50-year water supply and demand projections included in any adopted GSP or management area plan includes oil and gas–related activity as a significant net consumer or other factor reducing available supplies over time. Almost all of the GSPs and management area plans explicitly exclude oil and gas operational areas, and exempted aquifers under the Underground Injection Control program (discussed below and in Section 4.9, Hydrology and Water Quality), from SGMA-regulated groundwater basins. Several identify the potential use of treated and/or blended oil and gas produced water as a potential source of new imported water that would increase available supplies for agricultural irrigation purposes and reduce potential groundwater demand over time. Consequently, the review of each of the GSPs and management area plans in the Project Area determined that none of the plans provided new information indicating that the Project's water supply and other SGMA-related impacts, including water quality, would be greater in magnitude or scope than previously considered. In contrast, the GSPs and management area plans do provide new information indicating that the importation of treated produced water from oil and gas operations into several SGMA plan areas could increase available water supplies and facilitate SGMA implementation.

The following sections describe water supply and demand for the Project Area and each of the three subareas and summarize water supply and demand information in the adopted SGMA GSPs and management area plans in the Project Area.

Project Area Water Supplies

Water supplies in the Project Area are obtained from: (1) imported surface water from the State Water Project (SWP) and federal Central Valley Project (CVP); (2) local surface water, primarily in the Kern River and regulated flows from the Lake Isabella dam and reservoir; (3) secondary and tertiary-treated recycled water from 14 wastewater treatment plants in the San Joaquin Valley portion of Kern County; (4) produced water that is reused, primarily for oil and gas exploration and production activities and agriculture (excluding produced water disposed to the surface or by injection); and (5) groundwater.

Based on historical records for the San Joaquin Valley portion of the Kern County, on average groundwater accounts for about 37% of the total Project Area water supply. However, during dry years, groundwater can account for more than 60% of total supply. During dry years in 2007 and 2008, groundwater pumping made up approximately 69% of total supply compared with less than 10% during 2011, a recent wet year (2015 FEIR Appendix T-1). During the most recent drought, which peaked in 2014 and was subsequently followed by wetter years, portions of the Project Area did not receive any imported water and were totally dependent on groundwater. This reliance on groundwater negatively impacted groundwater levels in the Project Area, although groundwater conditions have recovered since 2017. For a more detailed summary of hydrological and groundwater conditions in California and the Project Area, the recent drought, and current conditions, see Section 4.9.2, Hydrology and Water Quality, Environmental Setting, of this SREIR.

The following sections summarize each of the primary water supplies in the Project Area.

Imported Surface Water

Imported surface water is used for agricultural, domestic, and municipal and industrial purposes and is the most important source of groundwater recharge in the Project Area. Water supply projections based on water agency and other sources typically distinguish between water used for agricultural purposes and domestic, municipal, and industrial purposes. As discussed in Section 4.9, Hydrology and Water Quality, certain oil and gas exploration and production activities require the use of higher-quality water supplies than can typically be obtained from produced water sources. Water for these activities comes from a variety of sources, including groundwater and imported or other surface water that could also be used for agricultural or domestic, including municipal and industrial, purposes. These activities include supplemental steam generation for enhanced oil recovery (EOR) use, drilling and cementing processes for new well construction, well stimulation treatments, and well maintenance and abandonment. Water sources (other than produced water) that are used for oil and gas exploration and production in the Project Area, including domestic and irrigation-quality water, are collectively referred to as “municipal and industrial (M&I) water” or “domestic and irrigation-quality water” in the 2015 FEIR and in this SREIR.

Imported water avoids the use of groundwater when available, and is percolated into groundwater in several water banking facilities in wetter years for storage and use in drier periods. Figure 4.9-6 shows the locations of the primary water banking districts located in the Project Area. During the most recent drought, surface water supplies were significantly curtailed for several successive years, significant banking and recharge using imported water has not been possible to achieve, and groundwater levels throughout the state, including the Project Area, were depleted.

State Water Project

The Project Area receives imported surface water from the SWP and CVP. The SWP is the largest state-built, multi-purpose water project in the United States and includes 33 storage facilities, 21 reservoirs and lakes, 24 pumping and generating plants, four hydroelectric power plants, and 660 miles of aqueducts. SWP facilities and deliveries are maintained and operated by the California Department of Water Resources (DWR). The SWP system conveys water to the Project Area that is primarily released from Oroville Dam on the Feather River and flows south to pumping facilities located on the southern edge of the Sacramento Delta.

SWP water supplies are allocated to 29 system contractors under the terms of water supply contracts with the DWR. The maximum amount of water per year that an SWP contactor may request is listed in Table A of each contract with the DWR and is referred to as the contractor's "Table A amount." As discussed below, actual deliveries vary with hydrologic conditions and may be significantly lower than the listed Table A amount in drier years and higher in wetter years. The Kern County Water Agency (KCWA) is the SWP contractor for the Project Area. Under current conditions, the maximum amount available for all 29 SWP contractors is 4.17 million acre-feet per year (AFY). The KCWA has a Table A amount of 982,730 AFY. The KCWA allocates SWP water under contracts with 13 Project Area water districts (WDs), or "member units," and to an improvement district that is operated by the KCWA for agricultural and municipal and industrial uses. Table 4.17-1 lists the KCWA member units and the maximum annual amount of SWP agricultural and M&I water each district could receive under its contract with the KCWA.

Table 4.17-1: Kern County Water Agency Member Unit State Water Project Contract Amounts

District/Agency	Agricultural Contract Amount (AF)	M&I Contract Amount (AF)	Total (AF)
Belridge WSD	121,508		121,508
Berrenda Mesa WD	92,600		92,600
Buena Vista WSD	21,300		21,300
Cawelo WD	38,200		38,200
Henry Miller WD	35,500		35,500
KCWA ID4	5,946	77,000	82,946
KCWA	8,000		8,000
Kern Delta WD	25,500		25,500
Lost Hills WD	119,110		119,110
Rosedale-Rio Bravo WSD	29,900		29,900
Semitropic WSD	155,000		155,000
Tehachapi-Cummings County WD	4,300	15,000	19,300
Tejon-Castac WD	3,278	2,000	5,278
West Kern WD	6,500	25,000	31,500
Wheeler Ridge-Maricopa WSD	197,088		197,088
TOTAL	**863,730**	**119,000**	**982,730**

Source: FEIR 2015 Appendix T-1, Table 5
Key:
AF = acre-feet
KCWA = Kern County Water Authority
M&I = municipal and industrial
WD = Water District
WSD = Water Storage District

Due to annual rainfall and snowpack variability, system storage levels, Sacramento Delta water quality and flow requirements for state and federally protected species, contractor demands, and other factors, the amount of water delivered to SWP contractors varies each year. According to the

KCWA, the agency received about 35% of the listed Table A amount in 2013 and about 5% in 2014, a critically dry year (KCWA 2014, 2015). SWP delivery rates were 20% in 2015, 60% in 2016, 85% in 2017, 35% in 2018, 75% in 2019 and, as of June 2020, are estimated to be 20% for water year 2020 (CRS 2020).

Table 4.17-2 shows the deliveries of SWP water supplied by the KCWA to member units from 2003 to 2012.

Table 4.17-2: State Water Plan Deliveries to the Kern County Water Agency, 2003–2012

Year	SWP Deliveries (AF)
2003	919,424
2004	771,898
2005	1,377,899
2006	1,242,631
2007	716,612
2008	279,334
2009	380,337
2010	469,319
2011	1,083,667
2012	584,589

Source: 2015 FEIR Appendix T-1, Table 6
Key:
AF = acre-feet
SWP = State Water Project

The DWR biannually analyzes the wet, normal, dry, and multiple dry year reliability of SWP system deliveries in draft and final SWP delivery capability reports (DCRs, formerly titled "Delivery Reliability Reports"). The most recent DCR is the Draft Delivery Capability Report 2019 (CNRA 2019). The report considers regulatory and judicial decisions affecting pumping levels from the Sacramento Delta, the potential effects of climate change, the hydrologic record in 1922 to 2015, and other factors to identify current and future delivery reliability, expressed as percentage of Table A contract amounts for SWP contractors, including the KCWA. Table 4.17-3 summarizes the projected deliveries of SWP water to the KCWA based on the reliability estimates in 2015 FEIR Appendix T-1. Table 4.17-3 shows that the SWP could deliver 58% to 62% of the Table A amounts for each contractor on a long-term average basis and that SWP deliveries during multiple-dry year periods would average about 31% of the Table A amounts and 11% during single dry years. The 2019 DCR indicates that the long-term average delivery capability of the SWP system is about 59 percent of Table A amounts, with single dry year deliveries ranging from 12% based on 1977 conditions to 7% based on 2014 conditions, and two- to six-year drought year average annual delivery rates of 25% to 29%. The 2019 DCR indicates that SWP long-term average supply reliability is consistent with the levels assumed in 2015 FEIR Appendix T-1, although single dry and multiple dry year reliability would be slightly lower than indicated in Tables 4.17-3 4.17-4.

Table 4.17-3: Kern County Water Agency State Water Project Supply Reliability 2015 to 2035

Wholesaler (Supply Source)	2015 (AF)	2020 (AF)	2025 (AF)	2030 (AF)	2035[b] (AF)
Average Water Year					
DWR (SWP)					
KCWA Table A Supply	594, 700	556, 300	556,300	556,300	556, 300
% of Table A Amount[a]	62%	58%	58%	58%	58%
Single Dry Year					
DWR (SWP)					
KCWA Table A Supply	115,000	105,500	105,500	105,500	105,500
% of Table A Amount[a]	12%	11%	11%	11%	11%
Multiple Dry Year					
DWR (SWP)					
KCWA Table A Supply	293,700	293,700	293,700	293,700	293,700
% of Table A Amount[a]	31%	31%	31%	31%	31%

Source: FEIR 2015 Appendix T-1, Table 7
Notes:
[a] Percentages of Table A amount based on DWR 2013 SWP Final Delivery Reliability Report. Assumes Table A contract amount of 982,730 AFY. The majority of Tejon-Castac Water District is located outside of the Project Area; thus their contract amount of 5,278 AF was excluded from future projections. A small portion of Tehachapi-Cummings County Water District (about 5%) is within the Project Area; thus, 5% of its contract amount (equivalent to 1,035 AFY) was included for future projections.
[b] The SWP Final Delivery Reliability Report contains projections through 2033. For the purposes of the WSA 2035 is assumed to be the same as 2033.
Key:
AF = acre-feet
AFY = acre-feet per year
DWR = Kern County Department of Water Resources
KCWA = Kern County Water Agency
SWP = State Water
WSA = Water Supply Assessment

Table 4.17-4 shows anticipated SWP delivery reliability by Subarea in average, single dry, and multiple dry years.

Table 4.17-4: State Water Project Delivery Reliability in Average, Dry, and Multiple Dry Years by Subarea 2015 to 2035

Year Types/Subareas	2015 (AF)	2020 (AF)	2025 (AF)	2030 (AF)	2035[a] (AF)
Average Water Year					
Central	183,100	171,300	171,300	171,300	171,300
Eastern	93,100	87,100	87,100	87,100	87,100
Western	318,500	297,900	297,900	297,900	297,900
TOTAL	**594,700**	**556,300**	**556,300**	**556,300**	**556,300**
% of Table A Amount	62%	58%	58%	58%	58%
Single Dry Year					
Central	35,400	32,500	32,500	32,500	32,500
Eastern	18,000	16,500	16,500	16,500	16,500
Western	61,600	56,500	56,500	56,500	56,500
TOTAL	**115,000**	**105,500**	**105,500**	**105,500**	**105,500**
% of Table A Amount	12%	11%	11%	11%	11%
Multiple Dry Year					
Central	90,400	90,400	90,400	90,400	90,400
Eastern	46,000	46,000	46,000	46,000	46,000
Western	157,300	157,300	157,300	157,300	157,300
TOTAL	**293,700**	**293,700**	**293,700**	**293,700**	**293,700**
% of Table A Amount	31%	31%	31%	31%	31%

Source: 2015 FEIR Appendix T-1, Table 8
Note:
[a] A large portion of the Tejon Castac Water District is located outside of the Project Area; thus, its contract amount of 5,278 acre-feet was excluded from future projections. A small portion of Tehachapi-Cummings County Water District (about 5%) is within the Project Area and 5% of the Water District's contract amount (equivalent to 1,035 acre-feet per year) was included for future projections.
Key:
AF = acre-feet

SWP contractors are periodically able to access other water supplies, including "Article 21" water (water that is in excess of the current needs of SWP contractors and that is available under Article 21 of the DWR contracts), turnback pool water (unused Table A water that is "turned back" to the DWR and available to other contractors), and DWR dry year purchases. These potential water sources are discussed in more detail below. The availability of these potential deliveries is uncertain and dependent on hydrological conditions and regulatory constraints. To provide a conservative assessment, none of these potential water sources is included in the Project Area supply analysis. Article 21 water may be supplied when Sacramento Delta outflow requirements for environmental purposes have been met, SWP storage south of the delta is full, and there is available aqueduct conveyance capacity. However, recent regulatory and judicial decisions affecting the delta's flow requirements to protect certain fish species are anticipated to reduce the availability of Article 21 water under future conditions.

The turnback pool program allows contractors to sell ("turn back") excess Table A supplies to other contractors. In general, as urban contractor demands have increased, the amount of water turned back and available for purchase under this program has diminished over time. The 2019 DCR indicates that from 2009 to 2018, deliveries of turnback water to SWP contractors ranged from 0 in 2018 to 99,000 AF in 2013 and deliveries of Article 21 water ranged from 0 in 2012 and 2013 to 297,000 AF in 2016 (CNRA 2019).

The DWR has the authority to implement dry year water purchase programs in critically dry years. Water is purchased by the DWR, where available, and resold to contractors that may desire additional supplies. The amount, availability, and cost of water delivered under a dry year water purchase program is subject to multiple uncertainties and cannot be reliably predicted in any given year.

Central Valley Project

The CVP is a set of federal facilities that extend from north of Redding to areas near Bakersfield and to the South Bay Area. The CVP encompasses two of California's largest river systems: the Sacramento River, which flows south toward the Sacramento Delta, and the San Joaquin River, which flows north to the delta. The Friant Dam stores San Joaquin River flows in Millerton Lake northeast of Fresno. These supplies are routed south to the Project Area through the 151.8-mile-long Friant-Kern Canal, which terminates near the Kern River in southwest Bakersfield. The Friant-Kern Canal has a maximum capacity of 5,000 cubic feet per second (cfs), which decreases to 2,000 cfs at its terminus in the Project Area.

The CVP is operated by the U.S. Bureau of Reclamation (USBR). CVP supplies are generally allocated to long-term contractors on the basis of Class 1 ("firm") and Class 2 ("non-firm, hydrology dependent") amounts. Surplus supplies may be provided to other contractors on an irregular basis under Section 215 of the Reclamation Reform Act of 1982 ("Section 215" water). According to the KCWA, during 1950 to 2007, an average of 318,877 AFY of CVP water was delivered through the Friant-Kern Canal to the Project Area for agricultural and M&I uses (Kennedy/Jenks 2011).

The CVP long-term contractors in the Project Area include Arvin-Edison Water Storage District (WSD), Delano-Earlimart Irrigation District (ID), Kern-Tulare WD, Shafter-Wasco ID, and Southern San Joaquin WSD. Water districts that are not contractors with the USBR in the Project Area occasionally exchange other supplies for CVP water, including the KCWA, Kern Delta WD, North Kern WSD, Rosedale-Rio Bravo WSD, and Semitropic WSD. Since 2003, deliveries of CVP water to the contractors and exchange districts within the Project Area have ranged from 260,000 AF (2007) to 800,000 AF (2005). Table 4.17-5 summarizes the CVP deliveries to the Project Area during 2003 to 2012, including to long-term contractors and by exchanges to non-contractors. Since 2012, CVP deliveries to contractors located to the south of the Sacramento Delta have ranged from 100% for all classes and users, including agriculture, M&I and Friant Class 1 and Class 2 contractors in 2017, to a low of zero deliveries for agricultural, Friant Class 1 and Class 2 and 50% for M&I contractors in 2014 (CRS 2020).

The reliability of future CVP deliveries to the Project Area is affected by hydrological variability and a 2006 settlement of an 18-year lawsuit involving the U.S. Department of the Interior and Commerce Department, the Natural Resources Defense Council, and the Friant Water Users Authority (now Friant Water Authority) regarding fish habitat in the San Joaquin River below Friant Dam. The settlement and related federal legislation in 2009 require that significant amounts of water previously available to CVP Friant contractors, including Kern County, must, instead, be discharged to the river channel in an effort to create salmon and other fish habitats. A series of interim flows to the river were initiated in 2009, and more permanent “restoration” flows began in 2014. Restoration flow releases will range from approximately 71,000 AF in a critical dry year to approximately 556,000 AF in wetter years and will have a priority over existing contracts. In certain emergency drought conditions, restoration flows may be reduced for other purposes.

The level of CVP delivery reductions to the Project Area related to the 2006 settlement also depends on hydrological and other factors. Estimates indicate that average annual deliveries from Friant Dam will be reduced by 13% to 15% from prior levels. The potential availability of Section 215 water supplied in the Project Area will also likely fall by as much as 30,000 to 40,000 AFY (see 2015 FEIR Appendix T-1).

To provide a conservative assessment, future CVP delivery levels in the Project Area assume that only Class 1 (firm) contract supplies would be delivered under future conditions. This approach is conservative because Class 2, Section 215, or other exchange water may be available under certain conditions, but uncertain future hydrological and regulatory conditions are expected to reduce the probability that the CVP system will have surplus supplies. Hydrologic modeling of CVP operations for 1922 to 1994 was conducted during the 2006 settlement to estimate the water supply expected to be available under various hydrologic conditions (2015 FEIR Appendix T-1). The post-settlement operational model results were used to project the amount of CVP-Friant supplies of Class 1 water that would be delivered to the Project Area.

As shown in Table 4.17-6, the projections indicate that the Project Area would, on average, receive 305,600 AFY from the CVP system under future conditions, or 91% of the Class 1 water contract amounts. CVP deliveries would fall to 23% of Class 1 amounts during a single dry year (analogous to 1977 conditions), and to 68% during multiple dry year periods (based on the four-year drought in 1931 to 1934).

Table 4.17-5: Central Valley Project deliveries to Project Area, 2003 to 2012

Year	Arvin-Edison WSD (AF) [a]	Delano-Earlimart ID (AF) [a]	Kern-Tulare WD (AF) [a], [b]	Shafter Wasco ID (AF) [a]	Southern San Joaquin MUD (AF) [a]	KCWA (AF) [c]	Kern-Delta WD (AF) [c]	North Kern WSD (AF) [c]	Rosedale Rio Bravo WSD (AF) [c]	Semitropic WSD (AF) [c]	Total (AF)
2003	116,102	121,342	25,284	62,151	111,417	0	0	0	25,257	0	461,553
2004	33,795	128,219	53,574	53,761	101,178	0	0	0	0	0	370,527
2005	213,757	116,280	45,486	65,505	115,604	96,623	1,890	56,337	88,786	0	800,268
2006	178,484	121,275	24,846	69,703	118,151	42,736	1,829	59,023	0	883	616,047
2007	19,787	73,916	49,846	34,311	70,112	0	0	12,252	0	19,819	260,224
2008	54,173	112,531	46,047	49,366	92,458	9,412	0	5,019	0	0	369,006
2009	110,898	121,435	44,925	50,723	121,259	0	0	4,563	0	0	453,803
2010	207,275	178,123	78,164	64,670	117,714	0	0	0	0	0	645,949
2011	193,835	152,217	45,299	75,526	125,889	63,158	0	1,949	6,448	0	664,321
2012	23,572	106,598	57,637	34,140	75,961	0	0	0	0	0	297,908

Source: 2015 FEIR Appendix T-1, Table 9
Notes:
[a] CVP contractors.
[b] Combined deliveries from Friant-Kern Canal and Cross Valley Canal.
[c] Non-CVP contractors receiving CVP water by exchange with contractors.
Key:
AF = acre-feet
CVP = Central Valley Project
ID = Irrigation District
WSD = Water Storage District

Table 4.17-6: Central Valley Project Area Delivery Reliability in Average, Dry, and Multiple Dry Years in the Project Area

CVP Water Supply Reliability	Delano – Earlimart ID (AF)	Shafter-Wasco ID (AF)	Southern San Joaquin MUD (AF)	Arvin-Edison WSD (AF)	Kern-Tulare WD (AF)	Total (AF)
Long-Term Average						
Class 1 Amount	99,000	45,500	88,300	36,400	36,400	305,600
% of Class 1 Amount	91%	91%	91%	91%	91%	
Single Dry Year						
Class 1 Amount	25,000	11,500	22,300	9,200	9,200	77,200
% of Class 1 Amount	23%	23%	23%	23%	23%	
Multiple Dry Year						
Class 1 Amount	74,000	34,000	66,000	27,200	27,200	228,400
% of Class 1 Amount	68%	68%	68%	68%	68%	

Source: 2015 FEIR Appendix T-1, Table 11
Key:
AF = acre-feet
CVP = Central Valley Project
ID = Irrigation District
MUD = Municipal Utility District
WD = Water District
WSD = Water Storage District

As shown in Table 4.17-7, most of the CVP water would be delivered to the Central Subarea, which would also experience the largest delivery reductions. The Central Subarea would receive 262,500 AFY (86%) of the CVP deliveries, and the Eastern Subarea would receive 13.5% in an average year. About 0.3% would be delivered to the Western Subarea. Dry and multiple dry year CVP deliveries would be reduced by 23% and 68%, respectively, in each Subarea.

Table 4.17-7: Central Valley Project Area Delivery Reliability in Average, Dry, and Multiple Dry Years by Subarea

CVP Water Supply Reliability	Western (AF) [(a)]	Central (AF) [(b)]	Eastern (AF) [(c)]	Total (AF)
Long-Term Average				
Class 1 Amount	900	262,500	42,200	305,600
% of Class 1 Amount	91%	91%	91%	91%
Single Dry Year				
Class 1 Amount	200	66,300	10,700	77,200
% of Class 1 Amount	23%	23%	23%	23%

Table 4.17-7: Central Valley Project Area Delivery Reliability in Average, Dry, and Multiple Dry Years by Subarea

CVP Water Supply Reliability	Western (AF) [(a)]	Central (AF) [(b)]	Eastern (AF) [(c)]	Total (AF)
Multi-Dry Year				
Class 1 Amount	700	196,200	31,500	228,400
% of Class 1 Amount	68%	68%	68%	68%

Source: FEIR Appendix T-1, Table 12
Notes:
(a) Includes Class 1 allocations from a portion of Arvin-Edison WSD (2%).
(b) Includes Class 1 allocations from the following agencies: Delano-Earlimart ID, Shafter-Wasco ID, Southern San Joaquin MUD, a portion of Arvin-Edison WSD (4%), and a portion of Kern-Tulare WD (77%).
(c) Includes Class 1 allocations from the following agencies: a portion of Arvin-Edison WSD (93%) and a portion of Kern-Tulare WD (23%).
Key:
AF = acre-feet
CVP = Central Valley Project
MUD = Municipal Utility District
WD = Water District
WSD = Water Storage District

The operation of the CVP system is subject to the implementation of recently reissued federal endangered species act biological assessments and opinions for species affected by CVP operations, most notably in the Sacramento Delta, and other ongoing state and federal water management and environmental protection issues. On May 26, 2020, the Congressional Research Service published un update on the “Central Valley Project: Issues and Legislation.” The update states that various state and federal proposals are currently under consideration and have generated controversy for their potential to affect CVP operations and allocations. In late 2018, the State of California finalized revisions to the Bay-Delta Water Quality Control Plan that would require that more flows from the San Joaquin and Sacramento Rivers reach the Bay-Delta for water quality and fish and wildlife enhancement (i.e., reduced water supplies for other users). “Voluntary agreements” that might replace some or all of these requirements are currently being negotiated but have yet to be finalized. Concurrently, the Trump Administration is aiming to increase CVP water supplies for users by making changes to long-term operations of the CVP, pursuant to a 2019 biological opinion created under the Endangered Species Act. California and environmental nongovernmental organizations have opposed these efforts and filed lawsuits to prevent implementation of the changes. On May 11, 2020, the court issued a preliminary injunction prohibiting the USBR from implementing the operational changes through May 31, 2020. Efforts to add or supplement CVP storage and conveyance also are being considered and are under study by federal and state entities (CRS 2020). As of June 2020, these issues are still pending and have not been resolved.

Local Surface Water

Local surface water in the Project Area is primarily obtained from Kern River flows, which are regulated by the Lake Isabella dam operated by the U.S. Army Corps of Engineers (USACE) and the Kern River Watermaster. Smaller streams, most of which are ephemeral, flow during periods of rain or for brief periods in the spring if they are fed by snowmelt and generally percolate into valley floor aquifers or, in limited instances, are used for agricultural irrigation. The Lake Isabella reservoir was designed to store approximately 570,000 AF of water. The facility's water storage has been limited to approximately 361,250 AF for safety purposes until the USACE upgrades the dam in accordance with an approved safety modernization program scheduled for completion in 2022 (USACE 2015).

The Kern River Watermaster coordinates reservoir releases with the U.S. Army Corps of Engineers to provide water for downstream users, primarily for irrigation and groundwater recharge. Table 4.17-8 summarizes the annual unregulated and regulated flow volumes in the Kern River from 1980 to 2011. In 1989 the State Water Resources Control Board (SWRCB) declared that Kern River was fully appropriated and that no new diversions would be considered for approval. The status of the river flows remains subject to an ongoing administrative appeal and related legal process that may alter the existing patterns of Kern River water use.

Table 4.17-8: Historic Kern River Flows

Year	Natural (AF)	Regulated (AF)	Year	Natural (AF)	Regulated (AF)
1980	1,639,957	1,560,652	1996	1,038,261	968,036
1981	449,263	460,469	1997	1,181,969	1,133,463
1982	1,271,139	1,121,088	1998	1,717,967	1,662,556
1983	2,489,128	2,381,575	1999	433,971	461,621
1984	821,797	834,036	2000	476,819	472,536
1985	1,444,939	668,971	2001	391,451	375,769
1986	375,935	1,331,561	2002	424,696	357,160
1987	294,685	432,309	2003	519,724	460,406
1988	397,038	335,473	2004	407,305	407,272
1989	203,571	348,773	2005	1,156,109	935,439
1990	406,289	219,501	2006	1,071,841	1,027,688
1991	296,829	333,494	2007	252,692	318,050
1992	853,760	272,822	2008	517,997	455,874
1993	1,385,160	642,339	2009	470,166	442,268
1994	336,456	422,361	2010	910,878	752,302
1995	1,385,160	1,197,100	2011	1,374,894	1,404,645

Key:
AF = acre-feet

Flows from minor streams also occur in the Project Area, particularly in the Central and Eastern Subareas. The mean flow of Project Area streams, other than Kern River, is 98,900 AF (Kennedy/Jenks 2011). To provide a conservative assessment, local surface water supplies in the Project Area were assumed to be solely derived from the Kern River. Average year Kern River supplies were 764,400 AFY (2015 FEIR Appendix T-1) during 1970 to 2011. In 1977 Kern River diversions were 197,000 AF, and during the 1987–1991 drought, average diversions were 335,500 AF (2015 FEIR Appendix T). Table 4.17-9 summarizes the availability of Kern River water supplies in the Project Area during average, single dry and multiple-dry years based on 1970–2011 diversion records. The river water is assumed to be diverted and used in the Eastern Subarea, although some flows may reach the Central or Western Subareas in very wet years.

Table 4.17-9: Project Area Kern River Supplies in Average, Single Dry and Multiple Dry Years by Subarea

Water Year Type	Project Area (AF)	Western Subarea (AF)	Central Subarea (AF)	Eastern Subarea (AF)
Average Water Year (based on average diversions 1970 to 2011)	764,400	--	--	764,400
Single-Dry Water Year (based on diversions 1977)	197,000	--	--	197,000
Multiple Dry Year (based on average diversions 1987 to 1991)	335,500	--	--	335,500

Source: 2015 FEIR Appendix T-1, Table 15
Key:
AF = acre-feet

Recycled Water

In 2011, 54,000 AF of secondary and tertiary-treated recycled water was produced for use in the Project Area by 14 wastewater treatment plants in the San Joaquin Valley portion of Kern County. About 49,000 AF of the recycled water supply was used for agricultural irrigation (FEIR 2015 Appendix T-1). Many farming operations have also installed facilities that intercept water that would normally run off fields during irrigation ("tailwater") for reuse in the same or adjacent fields (from the foot of one field to the head of another). Based on regional planning estimates prepared by the KCWA and other water districts, the amount of secondary and tertiary treated recycled water from Project Area wastewater treatment plants and recycled tailwater from farming operations in the Project Area is about 77,000 AFY (FEIR 2015 Appendix T-1). This level of recycled water supply is conservative because several Project Area water suppliers and users are considering measures to increase recycled water production and use.

Produced Water from Oil and Gas Activities

As discussed in Section 4.9, Hydrology and Water Quality, oil and gas exploration and production activities in the Project Area also generate "produced water" (i.e., residual water from the separation of oil and gas after extraction). About 234,959 AF of produced water was generated during 2012 in the Project Area. The oil and gas industry reused 38% (88,812 AF) of this amount for EOR injection or other oilfield activities, and 16% (38,658 AF) was supplied to the Cawelo WD and other users for agricultural irrigation. About 84,571 AF (36%) of the produced water was disposed of into injection wells, and 30,931 AF (13%) was disposed in surface ponds.

For analysis purposes, the supply of produced water in the Project Area available for treatment and reuse in the future is assumed to be sufficient to meet the anticipated demand for reuse, including oilfield operations and agricultural irrigation. This is a reasonable assumption, given that approximately half of produced water is currently disposed of rather than reused. As shown in Tables 19 and 39 of 2015 FEIR Appendix T-1, the Project Applicant has estimated that, in 2015, about 93,106 AF of produced water will be reused for EOR and other oil and gas purposes. By 2035, oil and gas activities will utilize about 121,412 AF of produced water. The projections further assume that produced water use for agriculture will be 38,658 AFY under existing and future conditions. As a result, the total Project Area produced water supply, excluding produced water disposal by injection or to surface ponds, is projected to increase from about 131,764 AFY in 2015 to 160,070 AFY in 2035.

Groundwater

As discussed in Section 4.9, Hydrology and Water Quality, the Project Area primarily overlies the DWR-designated groundwater subbasin 5-022.14, which is called the "Kern County Subbasin." The KCS extends north from the White Wolf fault in the southern portion of the Project Area to the foothills bordering the Project Area to the east and west, and to the northern boundary of the County. In 2016, the DWR approved a basin boundary modification for the KCS that resulted in the creation of new subbasin 5-022.18, the "White Wolf subbasin," in the southern portion of the Project Area south of the White Wolf fault. The White Wolf subbasin was a part of the KCS prior to the approved boundary modification in 2016. A small portion of subbasin 5-022.13, the "Tule subbasin," extends into the Central Subarea of the Project Area from Tulare County to the north. A portion of subbasin 5-022.17, the "Kettleman Plain subbasin" extends into the Western Subarea, and a small part of subbasin 5-022.12, the "Tulare Lake subbasin" extends into the Central Subarea, from Kings County to the north. Small portions of Basin 3-019, the "Carrizo Plain basin," and Basin 3-013, the "Cuyama Valley basin," extend into the far southwest corner of the Western Subarea from San Luis Obispo County to the west. For more information about the current designation of groundwater basins and subbasins in the Project Area, please see Section 4.9.2, Hydrology and Water Quality, Environmental Setting in this SREIR. Historically, California law did not require that water well operators in the state, including the Project Area, report the amount of groundwater extracted for agricultural, M&I, or other uses, except when aquifers are subject to a court-imposed adjudication. Project Area groundwater is not managed under an adjudication. The IRWMP developed estimates of groundwater extraction in the Project Area based on land uses and other water supplies. Table 4.17-10 summarizes the estimated amount of groundwater extracted in the Project Area from 1980 to 2011.

Table 4.17-10: Estimated Annual Project Area Groundwater Extraction, 1980 to 2011

Year	Extractions (AF)	Year	Extractions (AF)
1980	977,000	1996	1,609,600
1981	1,161,000	1997	1,091,400
1982	802,200	1998	1,290,200
1983	762,700	1999	1,471,500
1984	1,252,200	2000	1,360,100
1985	1,293,800	2001	1,953,900
1986	947,600	2002	1,575,000
1987	1,208,700	2003	1,203,900
1988	1,540,000	2004	1,842,300
1989	1,588,500	2005	579,900
1990	1,796,000	2006	716,500
1991	2,002,400	2007	2,212,300
1992	1,673,600	2008	2,306,500
1993	987,700	2009	1,212,400
1994	1,897,700	2010	230,400
1995	1,242,800	2011	419,000
		Mean [a]	**1,319,000**

Sources: 2015 FEIR Appendix T-1, Table 16
Note:
[a] Mean of the historical records is rounded off to the nearest hundred. The historical mean extraction value and estimates for normal, dry and multiple dry periods do not represent the safe or sustainable yield for the Project Area. See FEIR 2015 Appendix T-1, Section 4.3.4.1.
Key:
AF = acre-feet

Project Area groundwater use tends to increase during drier periods when surface supplies decrease. As discussed in Section 4.9, Hydrology and Water Quality, groundwater withdrawals have been particularly significant in response to the recent drought and reduced aquifer storage and groundwater elevations to historically low levels in many locations. Prior to the drought, the IRWMP identified groundwater overdraft as "one of the longest-standing issues in the Kern Region," and also indicated that the region including the Project Area may experience a net loss to storage due to groundwater pumping of approximately 325,000 AFY (Kennedy/Jenks 2011). In November 2014, the DWR published a public update on drought conditions in California indicating that groundwater in the Tulare Lake Basin, which includes the Project Area, has experienced notable declines since 2011, including reductions in the range of 25 to 50 feet to historically low levels (DWR 2014). As discussed in Section 4.9.2, Hydrology and Water Quality, Environmental Setting of this SREIR, the SGMA Annual Report submitted by the KCS Groundwater Sustainability Agencies (GSAs) to the DWR in April 2020 indicates that groundwater conditions improved from water year 2016 to water year 2019 as the drought receded and above average rainfall years occurred (KCSGSAs 2020).

For analysis purposes in the 2015 FEIR, the mean volume of estimated groundwater extractions during 1980 to 2011, 1.319 million AF, was assumed to represent average year demand for groundwater in the Project Area. The amount of groundwater extracted in a single dry year was assumed to be the average groundwater use during dry and critically dry years, as defined by the DWR for 1980 to 2011. The amount of groundwater extracted during multiple dry years is assumed to be the average level of extraction estimated to have occurred during the 1987–1992 drought. Project Area and Subarea groundwater use in average, dry, and multiple dry years is summarized in Table 4.17-11. As discussed in the 2015 FEIR and 2015 FEIR Appendix T-1, these groundwater use estimates are not intended to and do not represent an estimated safe yield for Project Area groundwater use. Any such use would only occur in conformance with applicable legal and regulatory requirements, including Groundwater Sustainability Plans (GSPs) adopted by the GSAs in the Project Area in accordance with the SGMA.

Table 4.17-11: Project Area Average, Dry and Multiple Dry Year Groundwater Supplies by Subarea

	Project Area (AF)	**Western Subarea (AF)**	**Central Subarea (AF)**	**Eastern Subarea (AF)**
Average Water Year (based on average extractions 1980–2011)	1,319,000	659,500	237,400	422,100
Single-Dry Water Year (based on average of dry and critical years of extractions 1980–2011)	1,673,000	836,500	301,100	535,400
Multiple Dry Year (based on average extractions 1987–1992)	1,635,000	817,450	294,300	523,200

Source: 2015 FEIR Appendix T-1, Table 17
The historical mean extraction value and estimates for normal, dry and multiple dry periods do not represent the safe or sustainable yield for the Project Area. See 2015 FEIR Appendix T-1, Section 4.3.4.1.
Key:
AF = acre-feet

Groundwater extractions by Subarea were estimated based on the assumption that groundwater extractions would be proportional to the estimated agricultural demand within each Subarea. Groundwater supplies may not be available for all uses in each Subarea.

As discussed in Section 4.9.2, Hydrology and Water Quality, Environmental Setting, an adopted GSP ensures that, over a period of 20 years, "sustainable groundwater management" is achieved, including the avoidance of "chronic lowering of groundwater levels" and "significant and unreasonable" reductions in groundwater storage, land subsidence, and "adverse impacts on beneficial uses." For more information concerning SGMA management, GSAs, and GSPs in the Project Area, please see Section 4.9.2, Hydrology and Water Quality, Environmental Setting.

As discussed Section 4.9.3, Hydrology and Water Quality, Regulatory Setting, the DWR enacted SGMA emergency regulations (the "SGMA regulations") in 2016. Among other provisions, the SGMA regulations require that the adoption of multiple GSPs for a designated basin or subbasin be coordinated in accordance with a Coordination Agreement and consistently managed in accordance with a coordinated water budget covering a 50-year planning and implementation horizon. Five GSPs and 15 Management Area plans have been adopted by multiple GSAs for the KCS. The KCS GSAs have adopted a Coordination Agreement and developed a coordinated water budget for the KCS covering the period from 2021 to 2070 as required by the SGMA and the SGMA regulations. The coordinated water budget, and supply and demand information developed for the water budget and to implement SGMA planning in the Project Area, are discussed in more detail below.

Project Area Supply Summary

Table 4.17-12 summarizes the Project Area water supplies that were estimated to be available for the Project Area, including SWP and CVP imported water, Kern River water, recycled water, oilfield-produced water, and groundwater, and that are estimated to be available in 2035, as stated in 2015 FEIR Appendix T-1.

Table 4.17-12: Summary of Project Area Average, Single Dry, and Multiple Dry Year Water Supplies, 2015 and 2035

	Average (AF)	**Single-Dry Year (AF)**	**Multiple Dry Year (AF)**
2015			
SWP Imported Water	565,900	105,500	293,700
CVP Imported Water	305,600	77,200	228,400
Groundwater	1,319,000	1,673,000	1,635,000
Kern River	764,400	197,000	335,500
Recycled Water	77,000	77,000	77,000
Oilfield-Produced Water [(a)]	131,764	131,764	131,764
TOTAL	**3,163,664**	**2,261,464**	**2,701,364**
2035			
SWP Imported Water	565,900	105,500	293,700
CVP Imported Water	305,600	77,200	228,400
Groundwater	1,319,000	1,673,000	1,635,000
Kern River	764,400	197,000	335,500
Recycled Water	77,000	77,000	77,000

Table 4.17-12: Summary of Project Area Average, Single Dry, and Multiple Dry Year Water Supplies, 2015 and 2035

	Average (AF)	Single-Dry Year (AF)	Multiple Dry Year (AF)
Oilfield-Produced Water	160,070	160,070	160,070
TOTAL	**3,191,970**	**2,289,770**	**2,729,670**

Source: 2015 FEIR Appendix T-1, Table 20
Note:
[a] "Oilfield produced water supply" includes 38,658 AFY provided for agricultural reuse in the Eastern Subarea. As noted in 2015 FEIR Appendix T-1, for ease of reference, this level of agricultural use was not included in Appendix T-1, Table 20 due to the different methodology used in Table 20 and was incorporated in.
Tables 39 and 41 through 43 of Appendix T-1. Consequently, Table 4.17-12 shows a higher amount of oilfield-produced water than Appendix T-1, Table 20. In addition, the total supply shown in Tables 39 and 41 through 43 of Appendix T-1 and Tables 4.17-28 to 4.17-30 provide a lower, more conservative estimate of normal, dry and multiply dry year supplies available in the Project Area than shown in Appendix T-1, Table 20 and Table 4.17-12.
Key:
AF = acre-feet
AFY = acre-feet per year
CVP = Central Valley Project
SWP = State Water Project

Project Area Water Demand

The primary sources of water demand in the Project Area are agriculture; urban use, including residential commercial, industrial, public service (e.g., schools, parks, recreation) and other urban M&I demand; and oil and gas exploration and production. The following sections summarize the water demands for each of these uses in the Project Area, as estimated in 2015 FEIR Appendix T-1.

Agricultural Water Demand

Agricultural water demand was estimated using the per-acre water application rate for the major crops grown multiplied by the acreage of each crop in the Project Area. As shown in Table 4.17-13, based on 2006 land use data prepared by the DWR, about 886,000 acres are used for irrigated agriculture in the Project Area. The average consumption per irrigated acre ranges from less than 2 AFY per acre to more than 4 AFY per acre, depending on the type of crop under cultivation.

Table 4.17-13: Project Area Agricultural Acreage, Crop Application Rates and Water Demand

Crop Type	Irrigated Area (acres)	Consumptive Water Use (AF/acre)	Agricultural Water Demand (AFY)
Alfalfa and Alfalfa Mixtures	90,129	4.10	369,529
Almonds	171,273	3.28	561,776
Apples, Pears, Plums	3,958	3.45	13,655
Apricots, Nectarines, Peaches	4,890	3.35	16,383
Beans (dry and green)	3,811	2.11	8,041

Table 4.17-13: Project Area Agricultural Acreage, Crop Application Rates and Water Demand

Crop Type	Irrigated Area (acres)	Consumptive Water Use (AF/acre)	Agricultural Water Demand (AFY)
Carrots	24,684	2.55	62,944
Citrus (grapes, lemons, oranges)	60,566	3.37	204,108
Corn, Grain Sorghum	26,659	2.95	78,644
Cotton	103,302	2.71	279,949
Grapes(Vineyards)	103,371	2.81	290,471
Grain and Grain Hay	110,184	2.07	228,080
Melons, Squash, Cucumbers	4,375	1.46	6,388
Misc. Deciduous Trees	15,996	3.34	53,427
Misc. Field Crops	47,972	2.09	100,261
Misc. Subtropical Trees	669	3.38	2,263
Misc. Vegetables	6,785	1.62	10,991
Nursery	5,145	3.28	16,875
Onions, Garlic	10,875	1.70	18,487
Pasture, Turf, Misc. Grasses	9,530	4.13	39,360
Pistachios	63,351	4.11	260,372
Potatoes	4,379	1.98	8,671
Safflower	1,304	2.23	2,909
Sugar Beets	574	3.29	1,888
Tomatoes	9,854	2.51	24,734
Walnuts	2,153	3.89	8,375

Source: 2015 FEIR Appendix T-1, Table 37
Key:
AF = acre-feet
AFY = acre-feet per year

Table 4.17-14 summarizes the irrigated acreage and agricultural water demand by Subarea. The Central Subarea accounts for about 50%, the Western Subarea accounts for about 32%, and the Eastern Subarea accounts for 18% of total Project Area agricultural demand. Agriculture was estimated to utilize about 2.669 million AFY in the Project Area in 215 FEIR Appendix T-1.

Table 4.17-14: Irrigated Agricultural Acreage and Water Demand by Subarea

Subarea	Irrigated Area (acres)	Agricultural Water Demand (AFY)
Western	289,404	867,309
Central	428,561	1,327,759
Eastern	167,863	473,619
TOTAL	**885,828**	**2,668,687**

Source: 2015 FEIR Appendix T, Table 38
Key:
AFY = acre-feet per year

For analysis purposes, existing agricultural water demand was conservatively assumed to remain constant in the 2015 FEIR, although urban development and other factors are likely to reduce irrigated acreage and water use in the Project Area over time.

Urban Water Demand

Urban demand projections were evaluated in 2015 FEIR Appendix T-1 for normal, single dry, and multiple dry years in five-year increments from 2010 to 2035, based on publicly available data, including urban water management plans (UWMPs) adopted by water agencies in the Project Area, the IRWMP, and the Poso Creek Integrated Regional Water Management Plan. Urban water demands include residential, commercial, industrial, institutional, landscape, and other public services, such as fire department, recreational, and school uses. Table 4.17-15 summarizes the average year urban water demand in the Project Area from 2010 to 2035 estimated in 2015 FEIR Appendix T-1. Average year urban water use in the Project Area was projected to increase from 237,028 AFY in 2015 to 301,736 AFY in 2035.

Table 4.17.15: Project Area Average (Average) Hydrologic Year Urban Water Demand 2010 to 2035

Subarea	Purveyor	2010 (AFY)	2015 (AFY)	2020 (AFY)	2025 (AFY)	2030 (AFY)	2035 (AFY)
Eastern and Central	California Water Service	77,177	84,029	80,644	86,788	93,400	100,513
Eastern and Central	City of Bakersfield	43,210	45,906	44,419	48,577	52,735	57,655
Eastern	East Niles CSD	8,942	9,238	9,569	10,042	10,583	11,572
Eastern and Central	North of the River MWD	8,400	8,800	9,200	10,000	11,000	11,000
Eastern and Central	Oildale MWC	8,173	7,930	7,768	8,524	9,324	10,194
Eastern	Greenfield CWD	2,843	3,108	3,398	3,715	4,061	4,440

Table 4.17.15: Project Area Average (Average) Hydrologic Year Urban Water Demand 2010 to 2035

Subarea	Purveyor	2010 (AFY)	2015 (AFY)	2020 (AFY)	2025 (AFY)	2030 (AFY)	2035 (AFY)
Central	Stockdale MWC and Annex	219	239	261	286	312	341
Central	Victory MWC	224	245	268	293	320	350
Western	Buttonwillow CWD	142	155	170	186	203	222
Eastern and Central	Vaughn WC	11,104	14,962	15,383	17,479	19,576	21,402
Western	West Kern WD	27,170	26,983	27,080	27,177	27,275	27,373
Central	City of Delano	9,271	11,785	11,785	13,021	14,387	15,900
Central	City of Shafter	4,739	5,037	5,322	5,171	5,708	6,302
Central	City of Wasco	4,681	6,661	8,925	11,469	14,293	17,397
Central	McFarland MWC	1,765	1,929	2,109	2,306	2,521	2,756
Eastern	Arvin CSD	3,472	3,796	4,150	4,538	4,961	5,424
Eastern	Lamont PUD	4,865	5,319	5,815	6,358	6,951	7,600
Central and Western	Lost Hills UD	462	506	553	604	661	723
Eastern	Tehachapi-Cummings CWD	367	401	439	480	524	573
	TOTAL	**217,226**	**237,028**	**237,257**	**257,014**	**278,795**	**301,736**

Source: 2015 FEIR Appendix T-1, Table 31
Note: The urban estimates exclude a small amount of urban demand in Casa Loma WC and Mettler CWD in the Central Subarea due to lack of available data. City of MacFarland demand is included in the MacFarland MWC totals.
Key:
AF = acre-feet
CSD = Community Services District
CWD = County Water District
MWC = Mutual Water Company
PUD = Public Utility District
UD = Utility District
WC = Water Company

Based on the data sources summarized above and in 2015 FEIR Appendix T-1, Project Area urban water demands in single dry and multiple dry years were also estimated under existing and future conditions. As shown in Table 4.17-16, urban water demands are estimated to be slightly lower in a single dry year and slightly higher during multiple dry years compared with normal or average year projections.

Table 4.17-16: Project Area Average, Single Dry and Multiple Dry Year Urban Water Demand 2015 to 2035

	2015 (AFY)	2020 (AFY)	2025 (AFY)	2030 (AFY)	2035 (AFY)
Average (Average) Year	237,028	237,257	257,014	278,795	301,736
Single Dry Year	234,938	236,461	255,928	277,418	299,970
Multiple Dry Year	239,853	241,170	261,009	282,901	305,885

Source: 2015 FEIR Appendix T-1, Tables 34-36
Key:
AFY = acre-feet per year

Table 4.17-17 shows Project Area urban water demand by Subarea for 2015 to 2035. Most of the urban water use in the Project Area occurs in the Eastern Subarea (49%) and Central Subarea (41%). The Western Subarea has a lower resident population and accounts for about 9% of Project Area urban water demand in an average year.

Table 4.17-17: Subarea Average, Single Dry and Multiple Dry Year Urban Water Demand 2015-2035

Subarea	2015 (AFY)	2020 (AFY)	2025 (AFY)	2030 (AFY)	2035 (AFY)
Average Year					
Western	27,471	27,613	27,760	27,912	28,070
Central	89,458	91,015	101,205	112,575	124,883
Eastern	120,100	118,628	128,049	138,308	148,783
TOTAL	**237,028**	**237,257**	**257,014**	**278,795**	**301,736**
Single Dry Year					
Western	30,169	30,321	30,478	30,640	30,808
Central	86,212	88,957	98,957	110,137	122,221
Eastern	118,557	117,182	126,493	136,640	146,942
TOTAL	**234,938**	**236,461**	**255,928**	**277,418**	**299,970**
Multiple Dry Years					
Western	29,973	30,124	30,280	30,441	30,609
Central	86,771	89,494	99,535	110,759	122,890
Eastern	123,110	121,551	131,194	141,700	152,387
TOTAL	**239,853**	**241,170**	**261,009**	**282,901**	**305,885**

Source: 2015 FEIR Appendix T-1, Tables 34-36
Key:
AFY = acre-feet per year

Oil and Gas Exploration and Production Demand

As discussed in 2015 Appendix T-1 and in Section 4.9, Hydrology and Water Quality, oil and gas exploration and production activities require the use of produced water, mainly for EOR steam and water injection purposes, and M&I water (which includes all irrigation and domestic water use) for well drilling and maintenance, well stimulation treatment, supplemental steam generation, and other operations that require higher quality water.

Produced Water Demand

Produced water is generated during the oil and gas extraction process from water that is located in oil-bearing formations. Oil and gas production wells bring a mixture of hydrocarbons and water to the surface. The extracted hydrocarbon and water mixture is routed to tanks and other facilities to separate the lighter oil and gas contents from heavier produced water. As shown in Figure 4.9-7 (see Section 4.9, Hydrology and Water Quality), the ratio of produced water to oil recovered in the Project Area has increased from under six units (e.g., gallons, barrels, or AF) of produced water for each unit of oil recovered in 2002 to nearly 13 units of produced water for each unit of oil recovered in 2012 and 2013. About 231,260 AF of produced water was generated along with the extraction of about 18,300 AF (141.6 million barrels) of oil in the Project Area in 2013.

As summarized in Section 4.9, Water Quality and Hydrology, produced water in the Project Area generally has relatively high levels of total dissolved solids (TDS), contains naturally occurring residual oil, grease, and other hydrocarbon-related constituents, and may contain elevated levels of boron, chloride, or other constituents that tend to occur in hydrocarbon-bearing formations. About 38% of the total volume of produced water in 2012, or 88,812 AF, was reused for EOR water and steam injections, pressure maintenance, well pulling, coil tubing activities, dust control, and surface facility construction. As shown in Table 4.17-18, produced water demand for oil and gas reuse is expected to be about 93,106 AF in 2015 and to increase to 121,412 AF by 2035.

Table 4.17-18: Oil and Gas Exploration and Production Demand for Produced Water 2012 to 2035

2012 (AFY)	2015 (AFY)	2020 (AFY)	2025 (AFY)	2030 (AFY)	2035 (AFY)
88,812	93,106	100,182	107,258	114,334	121,412

Source: 2015 FEIR Appendix T-1, Table 19 and Table 39

As discussed in Section 4.9, Hydrology and Water Quality, about 38,658 AFY of relatively high quality produced water from oilfields located along the base of the Sierra Nevada range in the Eastern Subarea is provided to the CWD and other users for agricultural reuse. Produced water reuse for irrigation requires additional filtration and treatment to meet applicable water quality standards, including waste discharge requirements (WDRs) issued by the Central Valley Regional Water Quality Board (CVRWQCB). The Applicant projected that 38,658 AF of produced water will continue to be supplied to the CWD in the Eastern Subarea through 2035. As discussed below, additional produced water reuse has been proposed or considered, including in several of the GSPs and Management Area plans adopted for the KCS, but none has been approved or implemented in other Project Area locations.

M&I Water Demand

As discussed in 2015 FEIR Appendix T-1, oil and gas exploration and production demand for M&I water was projected based on the ratio of water use for applicable activities per production well in the Project Area during 2012. M&I water is used for oil and gas operations that require higher water quality than can typically be obtained from produced water to protect equipment, avoid potential chemical reactions, and to avoid potential water quality impacts during well drilling when muds and drilling fluids could come into contact with water-bearing formations before well casings and cement seals have been installed. M&I water is used by oil and gas operators for: (a) drilling muds; (b) well stimulation treatments; (c) mud service, cementing, acidizing, and coil tubing maintenance; (d) well pulling; (e) domestic water use in oilfields and related structures; (f) well abandonment; and (g) steam production. As shown in Table 4.17-19, oil and gas M&I water demand in the Project Area was about 8,778 AF in 2012.

Table 4.17-19: Oil and Gas Exploration and Production Demand for Municipal and Industrial Water 2012

New Well Construction (Drill Mud + Well Stimulation)	589
Maintenance (Mud Services + Cementing)	61
Maintenance (Acidizing + Coil Tubing)	52
Maintenance (Well Pulling + Domestic Water)	594
Well Abandonment	202
Steam Production	7,279
TOTAL	8,778

Source: 2015 FEIR Appendix T-1, Table 28

As discussed in Chapter 3, Project Description, the Project Applicant has estimated that up to 2,697 new production wells could be subject to Oil and Gas Conformity Review under the proposed Zoning Ordinance amendment each year, 64% of which would be located in the Western Subarea, 5% in the Central Subarea, and 31% in the Eastern Subarea. As shown in Table 4.17-20, oil and gas M&I demand could increase to 11,760 AFY (or to 12,936 AFY, including a 10% contingency factor) by 2035 under these assumptions.

Table 4.17-20: Oil and Gas Exploration and Production Demand for Municipal and Industrial Water 2015 to 2035

	2015 (AFY)	2020 (AFY)	2025 (AFY)	2030 (AFY)	2035 (AFY)
Projected M&I Use	9,660	10,185	10,710	11,235	11,760
Projected M&I demand with 10% contingency	10,626	11,204	11,781	12,359	12,936

Source: 2015 FEIR Appendix T-1, Table 30
Key:
M&I = Municipal and Industrial

Oil and gas operators obtain M&I water from a variety of sources, including groundwater wells, deliveries from Project Area water purveyors, spot market purchases, or in truck-mounted tanks that are filled at industrial locations served by M&I suppliers. As discussed in 2015 FEIR Appendix T-1, 52 water purveyors were surveyed to determine if each had adopted a UWMP or an agricultural water management plan (AWMP) that identified oil and gas supply as a component of total service demand. The analysis identified 21 purveyors with adopted UWMPs or AWMPs that did not discuss oil and gas demand, 25 purveyors for which UWMPs or AWMPs were not available, and six purveyors with UWMPs or AWMPs that addressed oil and gas demand. The six purveyors include the Vaughn Water Company, West Kern WD, Oildale Mutual Water Company, Rag Gulch WD 2008 AWMP (currently incorporated into the Kern-Tulare Water District AWMP, which does not address oil and gas demand), Belridge WSD, and Lost Hills WD.

As shown in Table 4.17-21, the Belridge WSD (1,600 AFY) and the Lost Hills WD (708 AFY) were the only purveyors that quantified the amount of water expected to be provided to oil and gas operators over time. These two districts estimate that about 2,308 AFY of water will be supplied to oil and gas operators. A review of approved online well stimulation treatment notices posted by DOGGR between December 3, 2013, and March 6, 2014, identified the Belridge WSD, the West Kern WD, other “canal” and “Tulare” water, and groundwater as M&I water supply sources for oil and gas well stimulation activities (2015 FEIR Appendix S-1).

Table 4.17-21: Oil and Gas Exploration and Production Demand Identified in Project Area Urban Water Management Plans and Agricultural Water Management Plans

	2010 (AFY)	2015 (AFY)	2020 (AFY)	2025 (AFY)	2030 (AFY)	2035 (AFY)
Belridge 2012 AWMP	1,600	1,600	1,600	1,600	1,600	1,600
Lost Hills Water District 2012 AWMP	708	708	708	708	708	708
TOTAL	**2,308**	**2,308**	**2,308**	**2,308**	**2,308**	**2,308**

Source: 2015 FEIR Appendix T-1, Table 4
Key
AWMP = Agricultural Water Management Plan

As discussed in FEIR 2015 Appendix T-1, and in Impact 4.17-4, the analysis of supply and demand indicates that surplus water is not available in the Project Area. Any new use reduces the availability of water to another Project Area user, or increases the existing and severe regional groundwater overdraft if supply shortfalls are addressed by increased groundwater extraction. Due to the variability of oil and gas M&I supply sources from year to year, the recent drought that severely restricted the availability of imported and local surface supplies, and for conservative analysis purposes, the 2015 FEIR assumes that all oil and gas demands for M&I-quality water are met by using domestic and irrigation-quality groundwater.

Project Area Demand Summary

Table 4.17-22 summarizes the Project Area agricultural, urban, and oil and gas water demands in average, single dry, and multiple dry years for 2015 and 2035 analyzed in the 2015 FEIR.

Table 4.17-22: Summary of Project Area Average, Single Dry and Multiple Dry Year Water Demand, 2015 and 2035

	Average Year (AF)	**Single Dry Year (AF)**	**Multiple Dry Year (AF)**
2015			
Urban Demand (M&I)	237,029	234,938	239,854
Agricultural Demand (Excluding Produced Water)	2,630,029	2,630,029	2,630,029
Agricultural Demand (Produced Water Reuse)	38,658	38,658	38,658
Oil and Gas M&I Demand	9,660	9,660	9,660
Oil and Gas Produced Water Demand	93,106	93,106	93,106
TOTAL	**3,008,482**	**3,006,391**	**3,011,307**
2035			
Urban Demand (M&I)	301,736	299,971	305,886
Agricultural Demand (Excluding Produced Water)	2,630,029	2,630,029	2,630,029
Agricultural Demand (Produced Water Reuse)	38,658	38,658	38,658
Oil and Gas M&I Demand	11,761	11,761	11,761
Oil and Gas Produced Water Demand	121,412	121,412	121,412
TOTAL	**3,103,596**	**3,101,831**	**3,107,746**

Source: 2015 FEIR Appendix T-1, Table 39
Key:
AF = acre-feet
M&I = municipal and industrial

SGMA Implementation and Project Area Water Supply and Demand Information

This section summarizes water supply and demand information in SGMA-related information available since the 2015 FEIR was certified. Each GSP and management area plan adopted for any portion of the Project Area, including annual water budget projections, was reviewed to identify the extent to which oil and gas operations were identified as a significant factor affecting the achievement of SGMA objectives, including water supply and demand. None of the adopted GSPs and management areas plans within the Project Area identify oil and gas operations as a significant factor affecting the achievement of any of the SGMA objectives, including water supply and demand. Almost all of the GSPs and management area plans explicitly exclude oil and gas operational areas and exempted aquifers from SGMA-regulated groundwater basins. Several identify the potential use of treated and/or blended oil and gas produced water as a potential source of new imported water that would increase available supplies for agricultural irrigation purposes and reduce potential groundwater demand over time. For more information concerning the discussion of oil and gas activities, including produced water generation and use in each adopted GSP and management area plan in the Project Area, see Section 4.9.2, Hydrology and Water Quality, Environmental Setting, Project Area Groundwater Sustainability Plans and Oil and Gas Activities and Appendix D of this SREIR. For more information concerning the methodology used in this SREIR to update the water supply baseline with SGMA information since the 2015 FEIR was certified, see Section 4.9.2, Hydrology and Water Quality, Environmental Setting, Water Supply Baseline Update.

As discussed in Section 4.9, Hydrology and Water Quality, apart from small portions of DWR designated groundwater basins or subbasins primarily located outside of Kern County, five GSPs have been adopted in accordance with the SGMA for the KCS, which underlies the vast majority of the Project Area and Subareas. These GSPs include the Kern Groundwater Authority (KGA) GSP, the Kern River GSP, the Buena Vista GSP, the Olcese GSP, and the Henry Miller GSP. Section 354.20 of the SGMA regulations allows for the implementation of management area plans within the GSPs to implement the SGMA in response to local conditions. Fifteen Management Area plans have been prepared in conjunction with the KGA GSP:

- Arvin-Edison Water Storage District Management Area Plan (EKI Environment & Water 2019a)
- Cawelo GSA Management Area Plan (Cawelo GSA 2019)
- Eastside Water Management Area Plan (EKI Environment & Water 2019b)
- Kern County Water Agency - Pioneer Project Plan (Woodard & Curran 2019a)
- Kern Water Bank Authority Plan (Parker 2019)
- Kern-Tulare Water District Management Area Plan (KTWD 2019)
- North Kern Water Storage District - Shafter-Wasco Irrigation District Management Area Plan (GEI Consultants 2019a)
- Rosedale-Rio Bravo Management Area Plan (KGA 2019)

- Semitropic Water Storage District GSA Management Area Plan (GEI Consultants 2019b)
- Shafter-Wasco Irrigation District 7th Standard Annex Area Management Area Plan (EKI Environment & Water 2019c)
- Southern San Joaquin Municipal Utility District Management Area G Plan (GEI Consultants 2019c)
- Tejon-Castac Water District Management Area Plan (EKI Environment & Water 2019d)
- West Kern Water District Management Area Plan (Woodard & Curran 2019b)
- Westside District Water Authority Management Area Plan (Aquilogic, Inc. 2019)
- Wheeler Ridge-Maricopa Water Storage District Management Area Plan (EKI Environment & Water 2019e)

Additional information concerning SGMA planning and implementation in the five GSPs and 15 Management Area plans that have been adopted for the KCS, including information concerning the relationship of oil and gas activities with SGMA objectives in each of these areas, is provided in Section 4.9.2, Hydrology and Water Quality, Environmental Setting of this SREIR.

KCS GSA Annual Report

Section 356.2 of the SGMA regulations requires that GSAs submit an "annual report" to the DWR by April 1 of the each year following GSP adoption covering the preceding water year. The annual report must include descriptions of "groundwater elevation data," "groundwater extraction for the preceding water year," "surface water supply used or available for use, for groundwater recharge or in-lieu use shall be reported based on quantitative data that describes the annual volume and sources for the preceding water year," "total water use …using the best available measurement methods by water use sector" and "water source type," "change in groundwater in storage," and "a description of progress towards implementing the [GSP]." On April 1, 2020, the KCS GSAs submitted an annual report (referred to below as the "Annual Report") to the DWR in compliance with Section 356.2.

The Annual Report indicates that 1,284,183 acre-feet of groundwater extractions occurred in the KCS during water year 2019. Urban groundwater use was estimated to be 150,892 acre-feet (AF), or 12 percent of total extraction. The Annual Report states that "groundwater extractions for all urban uses" include "residential, commercial, municipal, industrial, oilfield use, landscaping and other uses." Agricultural groundwater use was estimated to be 1,096,779 AF, 85 percent of total extractions. About 3 percent of the groundwater use during water year 2019 was associated with "groundwater extractions by managed recharge operations that are returned to either the California Aqueduct or Friant-Kern Canal as a "pump-in" for water exchanges or for unspecified end uses (KCS GSAs 2020).

The Annual Report estimates that 2,805,400 AF of surface water was used in the KCS area during water year 2019, including 1,627,026 AF of imported federal CVP and SWP supplies, 1,065,772 AF of local surface water, and 37,133 acre-feet of recycled and "other" supplies. The Annual

Report states that 75,469 AF of the KCS water supply in 2019 was obtained from “local imported sources” and “surface water from local sources imported from areas outside of the Kern County Subbasin.” The report states that the “primary source of local imported water is from treated oilfield produced water.” The total water supply reported for the KCS in water year 2019 was 4,089,583 AF.

The Annual Report estimates that, net of an approximately 5 percent conveyance loss due to canal seepage that contributes to groundwater recharge, total water use in 2019 was 3,878,302 AF. Urban use, including oil and gas activities, was estimated to be about 199,977 AF. Agricultural use was estimated to be about 2,445,679 AF. Other water uses included managed wetlands (23,074 AF), managed groundwater recharge (1,173,060 AF) and other demand (36,512 AF). Over the period of 2016 to 2019, groundwater in storage increased by a total of 708,231 AF, or by an average of 177,058 AFY. In contrast, groundwater in storage declined by an average of -277,114 AFY from water year 1995 to water year 2014 (KCSGSAs 2020).

KCS Coordination Agreement and Coordinated Water Budget

As required by the SGMA and the SGMA regulations, the KCS GSAs executed a Coordination Agreement in January 2020 (KRGSA 2020, Appendix D). The purpose of the agreement is to “comply with SGMA coordination requirements and ensure that the multiple GSPs within the [KCS] are developed and implemented utilizing the same methodologies and assumptions as required under SGMA and Title 23 of the California Code of Regulations, and that the elements of the GSPs are appropriately coordinated to support sustainable management.” The agreement establishes a Basin Coordinating Committee, a plan manager, data and information exchange procedures, and a coordinated groundwater monitoring network. Consistent with SGMA Section 10727.6 and Section 357.4 of the SGMA regulations, the Agreement requires that each GSP for the KCS use the “same data and methodologies” for “(1) groundwater elevation data; (2) groundwater extraction data; (3) surface water supply; (4) total water use; (5) change in groundwater storage; (6) water budget; and (7) sustainable yield.” As required by Section 354.18 of the SGMA regulations, the agreement requires that the GSAs “prepare a coordinated water budget: for the KCS to provide “an accounting and assessment of the total annual volume of groundwater and surface water entering and leaving the [KCS] including historical, current and projected water budget conditions and change in the volume of water stored.” A coordinated water budget was completed for the KCS in January 2020 and attached to the Coordination Agreement.

The coordinated water budget ensures that all of the GSPs adopted in the KCS are based on consistent interpretations of the basin setting and use the same data and methodologies. The adopted SGMA goal for the KCS is to “(1) achieve sustainable groundwater management in the Kern County Subbasin through the implementation of projects and management actions at the member agency level of each GSA; (2) maintain its groundwater use within the sustainable yield of the basin as demonstrated by monitoring and reporting groundwater conditions; (3) operate within the established sustainable management criteria, which are based on the collective technical information presented in the GSPs in the subbasin; and (4) collectively bring the subbasin into sustainability and to maintain sustainability over the implementation and planning horizon.” The coordinated water budget was used to estimate current conditions for each GSA that are generally consistent with the basin-wide results under baseline conditions in the budget as required by the SGMA (KGA 2020).

The coordinated water budget is based on the DWR's C2VSim Fine Grid Beta Model with Kern County specific modifications (the "C2VSim FG-Kern" model). The model takes account of subbasin demand, including historical and projected urban and agricultural water use, and water supply, including surface water delivered from the CVP and SWP systems, local surface water, and other sources, such as treated produced water from oil and gas activities, that are considered to be imports to the subbasin. Groundwater is used as required to meet demand. In drier years, more groundwater is used to meet demand in the water budget analysis because surface supplies are limited. In wetter years, less groundwater is used because surface supplies are more abundant. As required by the SGMA, the coordinated water budget used historical hydrologic data and the C2VSim FG-Kern model to estimate the historical condition of the subbasin. Future conditions were analyzed by using a representative series of wet and dry water years for the region and by adjusting surface water availability levels to reflect regulatory and climate change constraints under varying future delivery reliability assumptions.

The net average annual change in groundwater storage derived from the model indicates the extent to which available supplies are sufficient to meet demand without unsustainably depleting groundwater. A negative annual average change in groundwater storage in the budget indicates that, over an applicable analysis period and hydrological cycle, groundwater use to meet demand given assumed surface water supplies would tend to exceed the net amount of groundwater recharge and cause one or more SGMA-defined undesirable results. A positive annual average change in groundwater storage would indicate that groundwater use to meet demand with other assumed water sources would not exceed the basin's groundwater recharge and would be sustainable over time. The coordinated water budget was used to estimate the average annual change in stored groundwater for historical conditions (1995 to 2014) and for 2021 to 2070 under a baseline, a climate change 2030, and an climate change 2070 scenario. The baseline scenario assumes that future surface water supplies will be reduced by approximately 20 percent from historical levels, primarily due to regulatory constraints reducing the volume of SWP imports. The climate change 2030 and 2070 analyses are based on the DWR's Climate Change Guidance and further reduce surface water supplies by approximately 2% and 6% from the baseline scenario assumptions (KGA 2020).

The coordinated water budget analysis of the three 2021–2070 scenarios considers annual average changes in groundwater storage with and without the implementation of proposed groundwater sustainability management actions and projects in the GSPs and the Management Area plans (referred to herein as the "SGMA Projects"). The SGMA Projects include groundwater recharge enhancement; agricultural and urban water use efficiency enhancement; voluntary land fallowing; groundwater pumping restrictions; stormwater and flood control improvements; water conveyance system improvements; programs to substitute surface water, when available, for groundwater use; and water quality enhancements to increase supplies available for beneficial use. Several GSPs and Management Area plans identify SGMA Projects that would increase the use of produced water for irrigation and other purposes in the KCS. The coordinated water budget indicates that the implementation of the SGMA Projects would improve the KCS water balance by approximately 421,000 AFY over the 50-year planning and implementation period to 2070 (KGA 2020, Appendix H). The proposed SGMA Projects, including projects that would develop and use produced water, are discussed in more detail in Section 4.9, Hydrology and Water Quality, Environmental Setting.

Based on the C2VSimFG-Kern model, the water budget indicates that groundwater storage declined by an average of -277,114 AFY in the KCS from water year 1995 to water year 2014. The safe yield of the basin was estimated to be approximately 1,313,000 AFY, with an uncertainty range of plus or minus 10 percent. The analysis results for 2021 to 2070 include the average annual groundwater storage change for 2021 to 2040, the "implementation period," and for 2041 to 2070, the "sustainability period." As required by the SGMA, the KCS must achieve sustainable groundwater management by 2040 and continue to be sustainably managed through 2070. The water budget analysis compares the average annual change in groundwater during 2041 to 2070 with the historical estimates for each of the three scenarios with and without the SGMA Projects, and with and without adjustments to account for excess subbasin surface and groundwater outflows.

Table 4.17-AA provides the coordinated water budget projections for the KCS under the baseline scenario without the implementation of the SGMA Projects. The analysis indicates that each year groundwater storage would increase or decrease in response to hydrological conditions. In very dry years, such as 2032 and 2052, groundwater storage would decrease by the largest amounts due surface supply reductions. In very wet years, such as 2029 and 2049, more abundant surface water would allow for significant groundwater recharge and large groundwater storage increases. The baseline analysis indicates that without the SGMA Projects, the average annual change in groundwater storage would be increasingly negative over time and average about -324,326 AFY during the 2041–2070 sustainability period.

Table 4.17-BB provides the coordinated water budget projections for the KCS under the baseline scenario with the implementation of proposed SGMA Projects. The analysis indicates that the SGMA Projects will reduce groundwater storage declines in drier years, such as 2032 and 2052, and increase recharge in wetter years, such as 2029 and 2049. The analysis indicates that with the SGMA Projects, the average annual change in groundwater storage would be increasingly positive over time and average about 42,144 AFY during the 2041–2070 sustainability period.

Table 4.17-CC summarizes the coordinated water budget analysis results for the baseline, 2030 climate change and 2070 climate change scenarios with and without SGMA Projects, and with and without excess outflow adjustments. The analysis indicates that the average annual change in groundwater storage during 2041 to 2070 would remain significantly negative, and higher than the historical estimate of -277,114 AFY for 1995 to 2014, in all three scenarios without the implementation of the SGMA Projects. The implementation of the SGMA Projects is projected to result in a positive annual average change in groundwater storage in the baseline scenario, and to significantly reduce and nearly eliminate the negative annual average storage change in the 2030 climate change scenario during 2041 to 2070. Adjusted to account for excess outflows, the annual average change groundwater storage would be 85,578 AFY in the baseline scenario and 46,829 AFY in the 2030 climate change scenario during the 2040-2070. The SGMA Projects reduce the

2070 climate change scenario annual groundwater storage deficit from -489,828 AFY to -118,273 AFY during 2041 to 2070. The 2041 to 2070 deficit in the 2070 climate change scenario is further reduced to -45,969 AFY with excess outflow adjustments.

As discussed in Section 4.9, Hydrology and Water Quality, 4.9.2, Environmental Setting, subsection SGMA Overview, the SGMA "is a complex program with a new language that must be mastered by consultants, basin managers, and stakeholders alike" as well as a "bold and untested groundwater management program." (Montgomery & Associates 2020). SGMA was adopted by California in 2014 and provides, for the first time in state history, "a framework for sustainable, groundwater management" resulting "in the management and use of groundwater in a manner that can be maintained during the planning and implementation horizon without causing undesirable results." The legislation and the governor's signing statement emphasize that "groundwater management in California is best accomplished locally." To achieve these objectives, "SGMA empowers local agencies to form Groundwater Sustainability Agencies (GSAs) to manage basins sustainably and requires those GSAs to adopt Groundwater Sustainability Plans (GSPs) for crucial groundwater basins in California" (DWR 2020; Maven's Notebook 2020). The SGMA process, including the formation of GSAs, the adoption of GSPs and management area plans, the development of technical hydrological information at a basin, subbasin, and plan level, and the consideration and integration of a wide range of interests affected by groundwater in accordance with the Act, has never before been attempted, let alone successfully implemented in California. The adopted GSPs and management area plans in the Project Area, including proposed SGMA Projects, represent initial approaches for implementing the SGMA that will be adaptively managed and revised as necessary to comprehensively meet SGMA requirements over the statutory 20-year compliance period and a 50-year planning and implementation horizon. For more information on the SGMA process, adaptive management, consideration of multiple groundwater interests, and comprehensive basin and subbasin sustainability see Section 4.9.2, Hydrology and Water Quality, Environmental Setting, SGMA Overview, in this SREIR.

Table 4.17-AA: Kern County Subbasin Coordinated Water Budget Baseline Scenario without Sustainable Groundwater Management Act Projects

Water Year Units	Deep Percolation Acre-feet	Managed Recharge and Canal Seepage Acre-feet	Net Stream Groundwater/Surface Water Interaction Acre-feet	Net Small Watershed Recharge Acre-feet	Groundwater Pumping Acre-feet	Subsurface Flow with Adjacent Groundwater Basins Acre-feet	Change in Groundwater Storage Acre-feet
SUMMARY: WY2021 to WY2070 Simulation Period							
Total	31,276,668	27,591,218	6,284,636	2,457,805	-80,359,227	-3,647,996	**-16,396,918**
Average	625,533	551,824	125,693	49,156	-1,607,185	-72,960	**-327,938**
SUMMARY: WY2021 to WY2040 Implementation Period							
Total	12,059,157	10,900,930	2,570,048	948,239	-31,618,403	-1,527,102	**-6,667,151**
Average	602,958	545,046	128,502	47,412	-1,580,920	-76,355	**-333,358**
SUMMARY: WY2041 to WY2070 Sustainability Period							
Total	19,217,510	16,690,288	3,714,588	1,509,566	-48,740,823	-2,120,894	**-9,729,767**
Average	640,584	556,343	123,820	50,319	-1,624,694	-70,696	**-324,326**
Annual Simulation Results for WY2021 to WY2070 Simulation Period							
2021	421,248	253,922	124,080	38,770	-1,605,058	-83,845	-850,883
2022	466,065	311,661	80,807	28,596	-1,881,001	-79,540	-1,073,415
2023	670,267	894,337	186,631	97,803	-1,082,942	-77,289	688,801
2024	782,933	971,636	250,700	67,141	-1,004,008	-81,747	986,650
2025	487,829	334,264	74,696	18,060	-1,956,094	-78,483	-1,119,730
2026	440,342	154,936	78,551	36,473	-2,258,997	-69,511	-1,618,207
2027	522,430	255,426	73,629	21,942	-1,995,091	-69,397	-1,191,063
2028	569,509	496,227	141,957	35,496	-1,490,383	-70,383	-317,575
2029	1,025,597	1,528,921	110,823	119,558	-891,968	-80,187	1,812,744
2030	692,430	587,522	63,468	19,157	-1,382,783	-79,634	-99,841
2031	550,146	164,041	109,295	19,161	-2,366,434	-73,780	-1,597,574
2032	459,496	111,528	66,581	18,134	-2,763,485	-65,268	-2,173,015
2033	742,600	875,129	188,075	126,420	-1,059,514	-71,675	801,034
2034	617,059	786,754	201,477	42,156	-1,422,316	-78,762	146,370
2035	691,055	727,363	294,732	52,652	-1,120,121	-82,586	563,094
2036	848,018	1,151,100	175,108	103,683	-890,760	-84,597	1,302,552
2037	617,636	539,499	102,463	32,114	-1,230,808	-82,549	-21,645
2038	517,060	379,550	106,226	26,241	-1,390,747	-77,398	-439,070

Table 4.17-AA: Kern County Subbasin Coordinated Water Budget Baseline Scenario without Sustainable Groundwater Management Act Projects

Water Year Units	Deep Percolation Acre-feet	Managed Recharge and Canal Seepage Acre-feet	Net Stream Groundwater/Surface Water Interaction Acre-feet	Net Small Watershed Recharge Acre-feet	Groundwater Pumping Acre-feet	Subsurface Flow with Adjacent Groundwater Basins Acre-feet	Change in Groundwater Storage Acre-feet
2039	495,144	190,829	65,868	25,370	-1,883,912	-72,405	-1,179,106
2040	442,293	186,285	74,884	19,311	-1,941,979	-68,067	-1,287,273
2041	466,980	254,002	124,912	34,980	-1,621,935	-66,834	-807,894
2042	519,154	311,722	81,095	28,467	-1,928,066	-66,378	-1,054,007
2043	723,193	894,377	183,602	100,835	-1,131,893	-66,724	703,389
2044	829,429	971,656	217,998	68,630	-1,055,212	-73,234	959,267
2045	520,072	334,263	67,722	18,136	-2,005,971	-71,742	-1,137,519
2046	465,742	154,936	78,954	36,599	-2,308,492	-64,094	-1,636,355
2047	542,433	255,426	73,991	22,117	-2,044,767	-65,020	-1,215,821
2048	587,534	496,227	142,442	35,645	-1,539,937	-66,665	-344,754
2049	1,038,285	1,528,924	111,871	121,871	-940,873	-77,190	1,782,886
2050	704,906	587,522	63,577	19,216	-1,430,758	-77,175	-132,713
2051	567,160	164,041	109,977	19,218	-2,411,967	-71,447	-1,623,019
2052	480,958	111,528	66,775	18,007	-2,776,754	-63,069	-2,162,556
2053	756,460	875,129	189,903	127,393	-1,105,182	-69,591	774,112
2054	629,422	786,754	203,667	42,236	-1,466,597	-76,937	118,546
2055	697,412	727,363	297,238	52,738	-1,163,909	-81,081	529,760
2056	955,260	1,151,202	186,248	169,221	-887,932	-83,323	1,490,676
2057	663,489	539,499	104,143	33,376	-1,272,005	-81,579	-13,077
2058	543,714	379,550	107,428	26,454	-1,432,264	-76,504	-451,623
2059	516,904	190,829	65,982	25,586	-1,924,204	-71,122	-1,196,025
2060	461,832	186,285	75,033	19,353	-1,923,734	-66,838	-1,248,069
2061	483,873	254,002	125,183	34,990	-1,662,322	-65,509	-829,782
2062	535,495	311,722	81,199	28,658	-1,968,451	-64,883	-1,076,261
2063	747,374	894,377	185,862	103,344	-1,173,248	-65,287	692,423
2064	797,596	971,656	227,478	42,092	-1,131,322	-72,135	835,365
2065	518,644	334,263	69,814	18,276	-2,046,917	-70,907	-1,176,825
2066	472,700	154,936	79,262	36,483	-2,350,004	-63,321	-1,669,944
2067	550,095	255,426	74,266	22,151	-2,087,215	-64,426	-1,249,703

Table 4.17-AA: Kern County Subbasin Coordinated Water Budget Baseline Scenario without Sustainable Groundwater Management Act Projects

Water Year Units	Deep Percolation Acre-feet	Managed Recharge and Canal Seepage Acre-feet	Net Stream Groundwater/Surface Water Interaction Acre-feet	Net Small Watershed Recharge Acre-feet	Groundwater Pumping Acre-feet	Subsurface Flow with Adjacent Groundwater Basins Acre-feet	Change in Groundwater Storage Acre-feet
2068	654,126	496,227	142,653	60,396	-1,488,744	-65,173	-200,515
2069	1,067,944	1,528,924	112,385	123,705	-984,856	-76,302	1,771,799
2070	719,324	587,522	63,930	19,394	-1,475,294	-76,404	-161,529

Table 4.17-BB: Kern County Subbasin Coordinated Water Budget Baseline Scenario with Sustainable Groundwater Management Act Projects

Water Year Units	Deep Percolation Acre-feet	Managed Recharge and Canal Seepage Acre-feet	Net Groundwater/ Surface Water Interactions Acre-feet	Small Watershed Inflow Acre-feet	Groundwater Pumping Acre-feet	Subsurface Flow with Adjacent Groundwater Basins Acre-feet	Change in Groundwater Storage Acre-feet
SUMMARY: WY2021 to WY2070 Simulation Period							
Total	33,771,527	32,630,931	5,233,643	2,457,805	-69,157,708	-5,025,601	**-89,422**
Average	675,431	652,619	104,673	49,156	-1,383,154	-100,512	**-1,788**
SUMMARY: WY2021 to WY2040 Implementation Period							
Total	13,100,548	12,612,730	2,239,160	948,239	-28,535,055	-1,719,340	**-1,353,732**
Average	655,027	630,637	111,958	47,412	-1,426,753	-85,967	**-67,687**
SUMMARY: WY2041 to WY2070 Sustainability Period							
Total	20,670,979	20,018,200	2,994,483	1,509,566	-40,622,653	-3,306,261	**1,264,311**
Average	689,033	667,273	99,816	50,319	-1,354,088	-110,209	**42,144**
Annual Simulation Results for WY2021 to WY2070 Simulation Period							
2021	430,153	302,373	123,650	38,770	-1,594,606	-83,189	-782,849
2022	475,303	349,553	80,614	28,596	-1,862,120	-78,565	-1,006,617
2023	770,374	1,002,929	168,647	97,803	-1,009,264	-78,404	952,085
2024	855,058	1,086,448	198,849	67,141	-944,665	-84,319	1,178,512
2025	503,643	350,298	70,663	18,060	-1,861,303	-81,925	-1,000,565
2026	440,243	214,542	77,894	36,473	-2,187,564	-73,190	-1,491,603

Table 4.17-BB: Kern County Subbasin Coordinated Water Budget Baseline Scenario with Sustainable Groundwater Management Act Projects

Water Year Units	Deep Percolation Acre-feet	Managed Recharge and Canal Seepage Acre-feet	Net Groundwater/ Surface Water Interactions Acre-feet	Small Watershed Inflow Acre-feet	Groundwater Pumping Acre-feet	Subsurface Flow with Adjacent Groundwater Basins Acre-feet	Change in Groundwater Storage Acre-feet
2027	518,989	316,584	73,092	21,942	-1,919,158	-73,183	-1,061,733
2028	578,749	623,230	137,529	35,496	-1,407,567	-75,335	-107,901
2029	1,194,895	1,696,947	83,255	119,558	-744,743	-87,273	2,262,638
2030	750,668	608,048	58,365	19,157	-1,257,759	-87,531	90,947
2031	555,404	180,833	107,613	19,161	-2,187,295	-83,584	-1,407,869
2032	453,293	125,476	66,634	18,134	-2,567,449	-76,460	-1,980,378
2033	824,902	1,059,059	172,274	126,420	-840,738	-84,135	1,257,782
2034	653,828	917,135	178,991	42,156	-1,197,621	-93,181	501,309
2035	827,370	931,556	238,868	52,652	-872,560	-98,679	1,079,205
2036	1,116,969	1,381,739	113,563	103,683	-633,072	-102,650	1,980,231
2037	725,584	594,384	63,749	32,114	-1,023,020	-100,141	292,669
2038	511,919	433,966	84,887	26,241	-1,154,051	-95,834	-192,873
2039	489,540	224,450	65,153	25,370	-1,627,860	-92,035	-915,382
2040	423,665	213,184	74,871	19,311	-1,642,642	-89,729	-1,001,340
2041	445,485	305,376	122,807	34,980	-1,354,885	-89,185	-535,423
2042	498,858	354,364	80,832	28,467	-1,639,112	-89,772	-766,363
2043	812,155	1,090,304	140,266	100,835	-882,848	-92,437	1,168,274
2044	892,628	1,153,766	138,151	68,630	-836,920	-100,949	1,315,306
2045	524,833	355,672	49,525	18,136	-1,730,147	-100,070	-882,051
2046	454,216	218,616	78,021	36,599	-2,055,875	-92,126	-1,360,549
2047	532,454	320,562	73,425	22,117	-1,809,154	-93,438	-954,033
2048	593,653	668,774	137,874	35,645	-1,324,186	-97,255	14,505
2049	1,234,198	1,750,812	79,492	121,871	-710,054	-110,080	2,366,239
2050	768,780	619,092	54,500	19,216	-1,197,582	-110,438	153,567
2051	578,825	192,400	107,098	19,218	-2,110,155	-106,461	-1,319,074
2052	479,637	135,929	66,695	18,007	-2,470,952	-99,536	-1,870,221
2053	850,038	1,095,469	170,484	127,393	-813,603	-107,867	1,321,915
2054	682,383	948,274	168,655	42,236	-1,143,633	-117,748	580,168
2055	858,469	966,141	223,989	52,738	-849,900	-123,451	1,127,986
2056	1,291,577	1,415,721	105,108	169,221	-638,704	-126,824	2,216,098
2057	807,949	600,599	52,465	33,376	-1,027,113	-123,865	343,411

Table 4.17-BB: Kern County Subbasin Coordinated Water Budget Baseline Scenario with Sustainable Groundwater Management Act Projects

Water Year Units	Deep Percolation Acre-feet	Managed Recharge and Canal Seepage Acre-feet	Net Groundwater/ Surface Water Interactions Acre-feet	Small Watershed Inflow Acre-feet	Groundwater Pumping Acre-feet	Subsurface Flow with Adjacent Groundwater Basins Acre-feet	Change in Groundwater Storage Acre-feet
2058	541,774	439,164	78,391	26,454	-1,146,168	-119,115	-179,499
2059	503,264	229,194	64,724	25,586	-1,627,673	-114,273	-919,179
2060	435,869	217,320	75,042	19,353	-1,597,610	-111,590	-961,617
2061	449,783	308,906	122,761	34,990	-1,363,117	-110,530	-557,207
2062	501,922	357,723	80,757	28,658	-1,643,414	-110,538	-784,892
2063	820,754	1,111,099	135,039	103,344	-898,437	-113,406	1,158,393
2064	871,279	1,174,447	124,818	42,092	-868,913	-122,551	1,221,172
2065	511,277	358,753	43,942	18,276	-1,750,481	-120,972	-939,204
2066	454,845	222,078	77,969	36,483	-2,077,330	-112,479	-1,398,433
2067	531,138	323,961	73,264	22,151	-1,832,363	-113,339	-995,189
2068	672,372	689,792	138,150	60,396	-1,265,870	-116,258	178,583
2069	1,286,647	1,771,462	77,455	123,705	-733,283	-129,909	2,396,076
2070	783,917	622,428	52,784	19,394	-1,223,170	-129,799	125,553

Table 4.17-CC: Kern County Subbasin Coordinated Water Budget Baseline, 2030 Climate Change and 2070 Climate Change Scenario Results with and without Sustainable Groundwater Management Act Projects and Excess Outflow Adjustments

	Change in Groundwater Storage (AFY)	
	C2vsimfg-Kern Model Results	**Adjusted Model Results**
Historic	-277,114	-277,114
Baseline	-324,326	-324,326
Baseline with Projects	42,144	85,578
2030 Climate Change	-380,900	-372,120
2030 Climate with Projects	-12,861	46,829
2070 Climate Change	-489,828	-472,336
2070 Climate with Projects	-118,273	-45,969

Key:
AFY = acre-feet per year

In 2017, the California legislature enacted temporary provisions codified in Water Code Sections 13808 et seq. that required the submission of certain water information in conjunction with applications to a city or county for new wells within a critically overdrafted basin. Among other information, Section 13808(a) requires that water well applicants provide information concerning the location, depth, and proposed capacity of the well; estimated pumping rates, anticipated pumping schedules, and estimated annual extraction volumes; geologic siting information; the distance from any potential sources of pollution onsite and on adjacent properties; the distance from ponds, lakes, and streams within 300 feet; existing wells on the property; the size of the area to be served by the well; and the planned category of water use, such as irrigation, stock, domestic, municipal, industrial, or other use. Section 13808.2 requires that the city or county "make the information . . . easily accessible and available to both the public and to groundwater sustainability agencies located within the basin where the new well is located, including "posting the information on the city's or county's Internet Web site . . .." These provisions were operative on January 1, 2018, and expired on January 31, 2020. During this period, the Kern County Public Health Services Department issued permits and water supply certificates for approximately 190 water wells and issued 374 approvals to drill water wells for property zoned appropriately and with an established use. The information required by the temporary provisions of the Water Code was provided to the KGA in accordance with Section 13808.2 of the Water Code. This change to the Water Code did not provide any additional authority to the County to regulate groundwater or limit water well permitting based on pumping information. Instead this provision is supportive of the SGMA authority to regulate groundwater pumping and coordinate with the county on water well permitting. The baseline used in 2015 is therefore not affected by this water well information and as shown in the Supplemental Water Supply Baseline Technical Report (2020) (see Appendix D of this SREIR).

Several of the SGMA Projects involve additional development and use of produced water for domestic or irrigation purposes. KGA members that have proposed to use produced water to meet SGMA objectives for the KCS include the Arvin-Edison WSD, the Cawelo WSD, the Eastside Water Management Area, the North Kern WD, and the districts in the Westside District Water Authority. These SGMA Projects are discussed in detail in the context of each GSP and Management Area plan adopted for the KCS, in Section 4.9, Hydrology and Water Quality,-4.9.2, Environmental Setting, *subsection Project Area Groundwater Sustainability Plans and Oil and Gas Activities, and Appendix D* of this SREIR. *For information concerning the use of produced water for agricultural irrigation, including the issuance of applicable permits by the CVRWQCB, and the ongoing Food Safety Project implemented in 2015 by the CVRWQCB to further assess the health and safety implications of using produced water for agricultural irrigation, see Section 4.9.3, Hydrology and Water Quality,-Regulatory Setting, Produced Water Reuse for Agricultural Irrigation in this SREIR.*

Electricity and Natural Gas

Pacific Gas and Electric Company (PG&E), Southern California Edison, and Southern California Gas Company (SoCalGas) provide electricity and natural gas to Kern County customers, with PG&E generally servicing the westerly portion of the County. SoCalGas also provides gas to customers in the western part of the County. PG&E's service territory, referred to as its "Kern Division," covers a large area of the County and includes Arvin, Bakersfield, Maricopa, McFarland, Ridgecrest, Shafter, Taft, Wasco, and unincorporated portions of the County. Within this area, PG&E serves gas and/or electricity to 154,000+ residential customers and about 23,000 commercial and industrial customers. Southern California Edison serves electricity to most of the remaining parts of the County, including the mountain, foothill, and southern desert communities of the County. This includes Delano, Lake Isabella, and Tehachapi, Mojave, Rosamond, and other unincorporated areas. SoCalGas provides gas-only service to various regions of Kern County.

Table 4.17-23 provides an estimate of the electricity and natural gas use in 1997, 2008, and 2012 for oil and gas production. The data indicate that there is an increased use of electricity over the time period, but a decreased used natural gas.

Oil and gas extraction energy use in the Project Area is a function of the location and amount of crude oil production, neither of which can be predicted with reasonable certainty under future conditions. If recent trends persist, oil production in the Project Area would require additional energy per barrel produced, but total energy use would continue to decline. Therefore, no new power generation plants or new major gas infrastructure would be needed to support the anticipated energy needs for the Project.

Table 4.17-23: Estimated Project Area CalGEM District 4) Electricity and Natural Gas Use 1997, 2008 and 2012 for Oil and Gas Production

Electricity			
Year	**Crude Oil production (kbbl)**	**Electrical use factor, Kkwh/kbbl**	**Annual use (Gwh)**
1997	213,053	12.98	2,765
2008	162,286	20.70	3,359
2012	141,694	25.18	3,568
Natural Gas			
Year	**Crude Oil production (kbbl)**	**Natural gas use factor, MBtu/kbbl**	**Annual use (TBtu)**
1997	213,053	1,147	244
2008	162,286	1,335	217
2012	141,694	1,444	205

Note: 1997 and 2008 calculated from statewide energy intensity factors (CEC 2013; see Table 2) and reported District 4 production (DOGGR 1998, 2009); 2012 estimated from 1997–2008 statewide energy intensity factors (CEC 2013; see Table 2) pro-rated by reported statewide crude oil production decline during 1997–2008 reported in the 2013 California Energy Balance update (CEC 2013) and reported District 4 production (DOGGR 2013).
Key:
DOGGR = Department of Conservation Division of Oil, Gas, and Geothermal Resources
Gwh = Gigawatt hours
kbbl = 1,000 barrels
Kkwh = 1,000 Kilowatt hours
MBtu = million British thermal units
TBtu = trillion British thermal units

Wastewater Disposal

Kern County Public Works Department, Operations Division

The Kern County Public Works Department, Operations Division operates two County Sanitation Districts: Kern Sanitation Authority and Ford City-Taft Heights Sanitation District, two wastewater plants (the Kern Sanitation Agency Treatment Plant and Taft Treatment Plant owned by Kern County (and two County Service Area) wastewater collection systems. The Board of Supervisors serves as the members of the Board of Directors for the two districts.

Wastewater treatment services within Kern County are provided by a number of local agencies, and the current flow and capacity of these facilities are presented in Table 4.17-24.

Table 4.17-24: Wastewater Flows and Capacity of Treatment Facilities in the Kern

Agency	Wastewater Facility	Current Flow (mgd)	Capacity Flow (mgd)
Kern Sanitation Authority	Buena Vista Aquatic Recreation Area Wastewater System[a]	0.016	0.2[m]
California City	California City Wastewater Treatment Plant[b]	0.8	1.5
City of Taft	Taft Federal Correctional Institution's Wastewater Treatment Plant[a]	0.35	0.5
City of Arvin	City of Arvin Wastewater Treatment Plant[c]	1.4	1.7
City of Bakersfield	City of Bakersfield Treatment Plant 2[d]	16.5	25
City of Bakersfield	City of Bakersfield Treatment Plant 3[a]	16.4[e]	32
City of Delano	City of Delano Wastewater Treatment Facility[a]	4.9	8.8
City of McFarland	City of McFarland Wastewater Treatment Facility[f]	1.1	1.55
City of Ridgecrest	City of Ridgecrest Wastewater Treatment Plant[g]	2.6	3.6
North of the River Sanitary District	City of Shafter/North of River Sanitary District Number 1 Wastewater Plant[h]	5.6	7.5
City of Tehachapi	City of Tehachapi Wastewater Treatment Plant[i]	0.830	1.25
City of Wasco	City of Wasco Wastewater Treatment Facility Plant[a]	1.7	3.0
Golden Hills Sanitation Company	Golden Hills Sanitation Company Wastewater Treatment Plant[g]	0.025	0.200
Kern Sanitation Authority	Kern Sanitation Authority Wastewater Treatment Plant[i]	3.8	4.0
Lamont Public Utilities District	Lamont Public Utilities District Plant[k]	1.4	2.0
Kern Sanitation Authority Service Area 39.8	Reeder Tract County Service Area 39.8 Wastewater System[a]	0.25	0.04[m]
Minter Field	Shafter Field Airport District Wastewater Plant[a]	0.15	0.2
Kern Sanitation Authority	Sheriff's Lerdo Facility Wastewater System[a]	0.30	0.54
Stallion Springs Community Services District	Stallion Springs Community Services District Wastewater Treatment Facility[i]	0.038	0.25
City of Taft	Taft Municipal Wastewater Treatment Facility[a]	1.3	1.5

Sources:
[a] Kennedy/Jenks2011
[b] California City Planning Department 2014
[c] Veloia Water 2014
[d] City of Bakersfield Public Works Wastewater Division 2015a
[e] City of Bakersfield Public Works Wastewater Division 2015b
[f] City of McFarland 2015
[g] Kreiger and Stewart, Inc. 2011
[h] City of Shafter 2014
[i] Integrated Resource Management, LLC 2008
[k] Lamont Public Utility District, n.d.
[m] Kern County Waste Management Department 2015

Key:
mgd = million gallons per day

Produced Water/Wastewater Disposal

Groundwater that exists naturally in oil and gas reservoirs is brought to the surface when oil and gas are extracted from these reservoirs. This water is known as "produced water." Produced water that is not reused for oilfield operations, or that is not treated and supplied to other users for agricultural irrigation, is disposed of by oilfield operators in surface impoundments (ponds) in accordance with WDRs issued by the CVRWQCB or is injected into Class II injection wells (discussed in more detail in Section 4.9, Hydrology and Water Quality) permitted by CalGEM. During 2012, oilfield operators disposed of about 30,000 AF of produced water into surface ponds, and 84,500 AF of produced water was disposed of by injection into Class II wells in the Project Area. The generation, reuse, and disposal of produced water, potential impacts associated with produced water activities, and mitigation measures required to reduce potentially significant impacts to less than significant levels, are discussed in Section 4.9, Hydrology and Water Quality. The regulation of produced water disposal, including regulatory updates and the implementation of programs concerning Class II wells by state and federal agencies, is discussed in more detail in Section 4.9, Hydrology and Water Quality.

Stormwater Drainage

The Kern County Public Works Department manages storm drain systems in Kern County. Development sites are required to provide for their own onsite retention or show that existing facilities have sufficient capacity to carry the additional runoff. These onsite retention basins are usually maintained by a County service area if they are for a residential project or privately maintained by the developer through a special district or other entity if they are for a commercial development. The County declines to assume liability for commercial or industrial drainage sumps, due to the issues of increased nonpoint-source contamination, particularly from industrial uses.

As discussed in Section 4.9, Hydrology and Water Quality, Impact 4.9-5, about 97.4% of the Project Area consists of Tier 1 and Tier 2 lands. Tier 1 lands, in which oil and gas activities are the predominant land use, represent 10.1% of the Project Area, while Tier 2 lands, where agriculture is the predominant use, represent 87.3% of the Project Area. In addition, 97% of the projected annual disturbance of up to 4,856 acres would occur in Tier 1 (4,400 acres) or Tier 2 (298 acres) areas. Urban-scale constructed stormwater drainage systems occur, to a limited extent, in Tier 1 and Tier 2 areas. Most drainage is managed on a site-specific basis in Project Area oilfields and agricultural locations. Potential project-related development would affect, at most, 0.3% of the acreage in Tiers 3, 4, and 5 that could generate runoff to existing or planned regional or constructed stormwater drainage systems.

Solid Waste

Kern County Public Works Department – Waste and Recycling Division

The Kern County Public Works Department, - Waste and Recycling Division provides environmentally safe management of solid waste and is responsible for operating seven landfills, five transfer stations, and three bin sites throughout the County. Kern County landfills are located in Bakersfield (Bena Landfill), Boron, Mojave-Rosamond, Ridgecrest, Shafter-Wasco, Taft, and Tehachapi.

The County Public Works Department Waste and Recycling Division also operates two special waste facilities and provides information to the residents of Kern County regarding recycling and ways to reduce waste. In addition, the department oversees the operation of several wastewater treatment facilities.

Solid waste is a mixture of items discarded as useless or unwanted arising from residential, commercial, industrial, institutional, agricultural, and mining activities. These wastes include construction and demolition (C&D)-generated waste as well as inert wastes. In most cases, solid waste is hauled directly to Class III landfills, with the remainder being taken to transfer stations, resource recovery centers, or refuse-to-energy facilities. Class III landfills typically handle the disposal of non-hazardous waste. The general waste classifications utilized by the Kern County Public Works Department, Waste and Recycling Division are:

- Non-hazardous solid waste, which consists mostly of household garbage, commercial wastes, agricultural waste, and litter;
- Special waste, which is any waste that requires special handling, including infectious waste, pesticide containers, sewage sludge, oilfield waste, household hazardous waste, and asbestos waste;
- Designated waste, which is a waste that consists of or contains pollutants that could be released at concentrations in excess of applicable water quality objectives and standards or hazardous waste that has been granted a variance from hazardous waste management requirements;
- Hazardous waste, which is a waste that, because of its quantity, concentration, physical, chemical, or infectious characteristics, may either: (a) cause or significantly contribute to an increase in mortality or an increase in serious irreversible or incapacitating reversible illness; or (b) pose a substantial present or potential hazard to human health or the environment when improperly managed; and
- Industrial wastes, which are hazardous and non-hazardous by-products produced by oil and gas extraction, pesticide, paper, petrochemical, rubber, plastics, electronics, and other industries.

Not all of the above-defined wastes may be disposed of at a landfill. State law regulates the disposal of wastes at landfills.

Kern County is responsible for compliance with the California Integrated Wastewater Management Act of 1989, AB 939. AB 939 requires that cities and counties reduce the amount of solid waste being sent to landfills by 50% by January 1, 2000, and requires cities and counties to prepare solid waste planning documents per AB 939. These documents include the Source Reduction and Recycling Element, the Household Hazardous Waste Element, and the Non-

Disposal Facility Element. All three of these documents have been approved for Kern County, as well as an Integrated Waste Management Plan approved February 1998 by the California Integrated Waste Management Board. The Kern County Integrated Waste Management Plan is the long-range planning document for landfill facilities.

C&D waste is heavy, inert material, which creates significant problems when disposed of in landfills. Since C&D waste is heavier than paper and plastic, it is more difficult for counties and cities to reduce the tonnage of disposed waste. For this reason, C&D waste has been specifically targeted by the State of California for diversion from the waste stream. Projects that will generate C&D waste should emphasize deconstruction and diversion planning, rather than demolition. Deconstruction is the planned and organized dismantling of a prior construction project, which allows maximum use of the deconstructed materials for recycling in other construction projects and sends a minimum of the deconstruction material to landfills.

The department administers or sponsors the following recycling programs that contribute to meeting the State-mandated solid waste diversion goals:

- Recycling programs at landfills to recycle or divert a wide variety of products, such as wood waste, cathode ray tubes, tires, inert materials, appliances, etc.;
- Kern County and the City of Bakersfield operate drop-off recycling centers for household recyclables located within the unincorporated metropolitan area and within the city. County and City drop-off recycling centers may be used by both County and City residents.
- Financial assistance for the operation of the City of Bakersfield Green Waste Facility;
- Kern County Special Waste Facility provides disposal of household hazardous waste services to all County residents;
- Cosponsors semi-annual Bulky Waste Collection Events, which are held in the Bakersfield area and are available to both County and city residents;
- Participates jointly with the City of Bakersfield in a Christmas tree recycling campaign;
- Cosponsors jointly with the Community Clean Sweep, a telephone book recycling program;
- Sponsors the Community Clean Sweep to conduct summer workshops called “Trash to Treasure,” which educates children on recycling and other Kern County Public Works Department, Waste and Recycling Division programs;
- Operates, in collaboration with the Community Clean Sweep, an innovative elementary school education program called “Clean Kids Hit the Road Puppet Show”
- Provides recycling trailers to churches, schools, and non-profit organization.

Landfills

Table 4.17-25 identifies the landfill class, maximum cubic yards, maximum tons per day, cubic yards per year, closure date, and remaining capacity date of the landfills in Kern County.

Table 4.17-25: Landfills in Kern County

Landfill Name and Location	Landfill Class	Permitted Capacity: Max Cubic Yards Per Year	Permitted Capacity: Max Tons Per Day	Remaining Cubic Yards	Closure Date Under Current Permits	Remaining Capacity Date
Public Landfills						
Bakersfield Metropolitan (Bena) Sanitary Landfill 2951 Neumarkel Road, Caliente, CA 93220	Class III	53,000,000	4,500	32,808,260	April 1, 2046	July 01, 2013
Boron Sanitary Landfill 11400 Boron Avenue, Boron, CA 93516	Class III	1,057,000	200	94,851	January 1, 2037	January 19, 2011
Clean Harbors Buttonwillow LLC 2500 West Lokern Road Buttonwillow, CA 93206	Class I	14,293,760	4,000	183,960,000	January 1, 2040	May 29, 2014
McKittrick Waste Treatment Site 56533 Highway 58, McKittrick, CA 93251	Class II	2,091,800	1,180	662,221	December 31. 2029	May 1, 2014
Mojave-Rosamond Sanitary Landfill 400 Silver Queen Road, Mojave, CA 93501	Class III	2,262,243	470	606,848	December 31. 2019	March 11, 2010
Ridgecrest Recycling & Sanitary Landfill 3301 Bowman Road Ridgecrest, CA 93555	Class III	10,500,000	701	5,037,428	December 31, 2045	September 16, 2010
Shafter-Wasco Recycling & Sanitary Landfill 17621 Scofield Ave., Shafter, CA 93263	Class III	21,895,179	1,500	14,534,860	December 31, 2027	May 23, 2014
Taft Recycling & Sanitary Landfill 13351 Elk Hills Road, Taft, CA 93268	Class III	11,000,000	800	7,380,708	December 31, 2078	February 01, 2011

Table 4.17-25: Landfills in Kern County

Landfill Name and Location	Landfill Class	Permitted Capacity: Max Cubic Yards Per Year	Permitted Capacity: Max Tons Per Day	Remaining Cubic Yards	Closure Date Under Current Permits	Remaining Capacity Date
Tehachapi Sanitary Landfill 12001 Tehachapi Blvd., Tehachapi, CA 93561	Class III	3,388,723	1,000	329,171	January 1, 2016	May 23, 2014
Private Use Landfills						
Edwards Air Force Base Main Base Sanitary Landfill, [1] [a] 220 Landfill Road, Edwards Air Force Base, CA 93524	Class III	2,250,000	120	1,078,875	December 31, 2028	Not Available
H.M. Holloway Landfill 13850 Holloway Road, Lost Hills, CA 93249	Class II, Class III	12,600,000	2,000	7,522,934	January 31, 2019	December 31, 2013
U.S. Borax Inc.-Gangue/ [2] [b] Refuse Waste Pile 14486 Borax Road, Boron, CA 93516	Class III	8,500,000	443	908,496	January 1, 2023	May 29, 2014

Sources:
CalRecycle 2013a
(1) CalRecycle 2009
(2) CalRecycle 2013b
Notes:
(a) Not a public landfill; only accepts waste generated at Edwards Air Force Base.
(b) Not a public landfill; only accepts waste derived solely from US Borax Boron Operations.
Operators are only required to update information every five years.

4.17.3 Regulatory Setting

Federal

Clean Water Act (33 U.S.C. §1251 et seq.)

The 1972 Federal Water Pollution Control Act and its 1977 amendments, collectively known as the Clean Water Act (CWA), established national water quality goals and the basic structure for regulating discharges of pollutants into the waters of the United States. Section 402 of the CWA establishes the National Pollutant Discharge Elimination System (NPDES) to regulate the discharge of pollutants into waters of the United States. Section 404 of the CWA regulates the discharge of fill or dredged materials to waters of the U.S. (see Section 4.4, Biological Resources of the 2015 SREIR). Section 404 is jointly implemented by the U.S. Environmental Protection Agency (EPA) and the U.S. Army Corps of Engineers, both of which are responsible for on-site investigations and enforcement of unpermitted discharges (EPA 2020). Permits issued under the CWA limit the composition and, in some cases, the volume of a discharge and the concentrations of individual pollutants. Discharge requirements are based on available technology (technology-based effluent limits) and on the quality of the receiving waters (water quality–based effluent limits).

The CWA allows for the delegation of implementation authority to the states. Under the federal or delegated program, all the information required for permit application and monitoring for permit compliance are considered public, with the exception of certain confidential business information that may be considered “trade secret.” In addition, the program requires delegated states to establish water quality standards for specific water bodies and to designate the types of pollutants to be regulated, including total suspended solids and oil and grease. In California, NPDES permitting authority is delegated to the SWRCB and nine Regional Water Quality Control Boards (RWQCBs). The Project Area is within the jurisdiction of the CVRWQCB.

Under the NPDES program, all point sources that discharge directly into waters of the United States are required to obtain a permit regulating their discharge. Each NPDES permit specifies effluent limitations for particular pollutants as well as monitoring and reporting requirements for the proposed discharge. Construction activities in the Project Area that could result in a discharge to waters of the United States are subject to the California NPDES General Permit for Stormwater Associated with Construction Activities (Construction Activity NPDES Storm Water General Permit, 2009-0009-DWQ and 2010-0014-DWQ). Other stormwater discharges could be subject to the Industrial General Permit issued under the NPDES program, to a municipal separate storm sewer system NPDES permit issued for municipal locations, or to individual NPDES permits issued to specific landowners or land use operators.

Discharges of treated wastewater to surface waters of the United States require a NPDES permit. In California, the RWQCBs administer the issuance of these federal permits. Obtaining a NPDES permit requires preparation of detailed information, including characterization of wastewater sources, treatment processes, and effluent quality. The conditions of a permit are subject to many factors, such as basin plan water quality objectives, impaired water body status of the receiving water, historical flow rates of the receiving water, effluent quality and flow, the California Toxics Rule (CTR), the SWRCB's State Implementation Plan implementing the CTR, and established Total Maximum Daily Loads (TMDLs) for various pollutants. More information about NPDES permits that apply to oil and gas operations is provided in the discussion of state permitting below.

Section 401 of the CWA requires that an applicant requesting a federal permit for an activity that may result in a discharge into waters of the United States obtain state certification that the proposed activity will not violate state or federal water quality standards. State water quality standards are discussed below. The CVRWQCB implements Section 401 of the CWA in the Project Area.

Total Maximum Daily Loads

Under Section 303(d) of the CWA, states, territories, and authorized tribes are required to develop lists of impaired waters. These are waters that exceed applicable water quality standards. The law requires that these jurisdictions establish priority rankings for waters on the lists and develop TMDLs for these waters. A TMDL is a calculation of the maximum amount of a pollutant that a waterbody can receive and still meet water quality standards.

There are no impaired waters listed within the Project Area, and no TMDLs have been established for surface waters in the Project Area.

Safe Drinking Water Act

The Safe Drinking Water Act of 1974 (SDWA) gave the EPA the authority to set standards for contaminants in drinking water supplies. The EPA was required to establish primary regulations for the control of contaminants that affected public health and secondary regulations for compounds that affect the taste, odor, and aesthetics of drinking water. Under the provisions of the SDWA, the California Department of Health Services (DHS) has primary enforcement responsibility. Title 22 of the California Administrative Code establishes DHS authority and stipulates state drinking water quality and monitoring standards. For additional information concerning regulatory updates and implementation of programs concerning the protection of underground sources of drinking water in accordance with the SDWA, including Class II well operations in the Project Area, the Underground Injection Control (UIC) program and updated UIC regulations, and the ongoing aquifer exemption program being implemented by CalGEM and the UEPA, see Section 4.9.2, Hydrology and Water Quality, Environmental Setting and Section 4.9.3, Regulatory Setting.

Federal Energy Regulatory Commission

The Federal Energy Regulatory Commission (FERC) regulates and oversees the energy industries in the interest of the American public. The Energy Policy Act of 2005 gave FERC additional responsibilities, including interstate commerce, licenses and inspections, energy markets, and penalizing energy organizers and individuals who violate FERC rules in the energy markets.

State

California Energy Commission

The California Energy Commission (CEC) regulates the provision of natural gas and electricity within the state. The CEC is the state's primary energy policy and planning agency. Created in 1974, the CEC has five major responsibilities: forecasting future energy needs and keeping historical energy data, licensing thermal power plants 50 megawatts or larger, promoting energy efficiency through appliance and building standards, developing energy technologies and supporting renewable energy, and planning for and directing the State of California's response to energy emergencies.

Water Code Sections 10910 et seq.

Water Code Section 10910 et seq. were amended by Senate Bill (SB) 610 in 2001 to require that a WSA be prepared by a public water system for certain projects subject to the California Environmental Quality Act (CEQA), including a proposed residential development of more than 500 dwelling units; a proposed shopping center or business establishment employing more than 1,000 persons or having more than 500,000 square feet of floor space; a proposed commercial office building employing more than 1,000 persons or having more than 250,000 square feet of floor space; a proposed hotel or motel, or both, having more than 500 rooms; a proposed industrial, manufacturing, or processing plant, or industrial park planned to house more than 1,000 persons, occupying more than 40 acres of land, or having more than 650,000 square feet of floor area; a mixed-use project that includes one or more of the projects specified in this subdivision; or a project that would demand an amount of water equivalent to, or greater than, the amount of water required by a 500-dwelling-unit project. Water Code Section 10910(b) further provides that the CEQA lead agency may prepare the WSA if a public water system that may supply water for the project cannot be identified. As discussed above, no public water system would provide more than a small portion of the water required for oil and gas activities in the Project Area.

The Applicant's consultant, Kennedy/Jenks, completed a draft water supply and demand analysis that includes the required elements of a WSA. The draft WSA was independently reviewed by the County and helped inform the water supply and demand analysis in this SREIR. A copy of the draft WSA is included in 2015 FEIR as Appendix T-1.

Senate Bill 1281, Disclosure of Oil and Gas Water Use and Disposal

SB 1281, effective January 2015, amended Sections 3226.3 and 3227 of the Public Resources Code (PRC) to require that: (1) CalGEM provide the SWRCB with an annual "inventory of all unlined oil and gas field sumps" and (2) well operators provide CalGEM with quarterly information regarding the source and disposition of water produced by or used in oil and gas production in addition to existing obligations to report gas and oil production and produced water information on a monthly basis. The new quarterly reporting requirements include information regarding: (a) the source and volume of any water, including produced water (also subject to monthly reporting), including the water used to generate or make up the composition of any injected fluid or gas, identified by water source if more than one water source is used; (b) the volume of untreated water suitable for domestic or irrigation purposes used in oil and gas operations; (c) the treatment of water and the use of treated or recycled water in oil and gas field activities including, but not limited to, exploration, development, and production; and (d) the specific disposition of all water used in or generated by oil and gas field activities, including water produced from each well as reported in an operator's monthly reports, and separated by volume of disposition if more than one disposition method is used.

The amendments retain certain previous monthly reporting requirements in Section 3227, including: (1) the amount and gravity of oil, gas and water, and the number of days fluid was produced from each well; (2) the number of drilling, producing, injecting, or idle wells owned or operated by a person subject to reporting requirements; (3) the disposition of gas produced from each field; (4) the disposition of produced water each field and the amount of fluid or gas injected into each well used for enhanced recovery, underground storage of hydrocarbons, or wastewater disposal. In August 2015 the SWRCB stated in a letter to CalGEM (then, DOGGR) that for the purposes of reporting under Section 3227, "water suitable for domestic or irrigation purposes" should be interpreted to mean water with a TDS concentration of 10,000 milligrams per liter (mg/L) or lower (CalGEM 2019a).

CalGEM periodically provides oil and gas well water use data in quarterly water use summary reports covering the state of California. In June 2020, CalGEM published quarterly summaries from the first quarter of 2015 to the second quarter of 2017. CalGEM also posted online spreadsheets containing certain raw data supplied by oil and gas operators under Section 3227 from the first quarter of 2015 to the fourth quarter of 2017. These spreadsheets are reviewed by CalGEM to compile and publish the quarterly water use summaries for the state on their website. CalGEM states that the water use reports do not include confidential information and, except for more limited coverage in the first quarter of 2015, the quarterly summaries cover approximately 90 percent of the state (CalGEM 2019b). The 2015 FEIR discussed the quarterly water use report prepared by CalGEM (then, DOGGR) for the first quarter of 2015, the report available at the time the FEIR was certified. The following summary updates the information in the 2015 FEIR to include the nine quarterly reports subsequently published by CalGEM from the second quarter of 2015 to the second quarter of 2017. As discussed in the 2015 FEIR, the first quarterly report in 2015, which was based on the earliest set of reports provided to CalGEM under Section 3227, covered about 65 percent of the state. Information from the first quarterly report is summarized for informational purposes but not utilized in the averages for the subsequent nine reports covering 90 percent of the state discussed below.

Table 4.17-DD summarizes the quarterly volume of produced water, produced water reported to be suitable for domestic and irrigation use, and produced water sold or transferred for domestic use in the state quarterly water use reports. Table 4.17-DD indicates that state oil and gas operators generated an average of just over 103,000 AF of produced water per quarter from the second quarter of 2015 to the second quarter of 2017. An average of 3,539 AF per quarter of produced water was reported as suitable for domestic or irrigation use. An average of 8,991 AF of produced water per quarter was sold or transferred for domestic use. *According to CalGEM, the sale or transfer of produced water for "domestic use" as reported in the quarterly water use reports means that the "water is used for agriculture, irrigation, water replenishment, water banking, livestock, etc." This*

definition of "domestic use" does not refer to any direct human consumption of or direct human contact with produced water. (DOGGR 2018)

Table 4.17-DD: Volume of Produced Water, Produced Water Suitable for Domestic or Irrigation Use, and Produced Water Sold or Transferred for Domestic Use, Senate Bill 1281 Quarterly State Water Use Reports

	Total (AF)	**Portion Suitable for Domestic or Irrigation Use (AF)**	**Sale/Transfer for Domestic Use (AF)**
2015 Q1 (partial coverage)	65,279	1,688	6,469
2015 Q2	103,304	6,444	8,626
2015 Q3	104,911	2,382	8,721
2015 Q4	105,943	2,382	9,654
2016 Q1	105,195	2,261	8,302
2016 Q2	103,552	1,870	9,132
2016 Q3	105,753	2,204	9,760
2016 Q4	100,554	2,179	9,545
2017 Q1	101,148	6,915	9,576
2017 Q2	100,652	7,062	10,127
Quarterly Average	103,446	3,539	8,991

Key:
AF = acre-feet
Q = quarterly

Table 4.17-EE summarizes the quarterly volume of injection and the portion of injected water reported to be suitable for domestic and irrigation use from the second quarter of 2015 to the second quarter of 2017. Table 4.14-EE indicates that state oil and gas operators injected an average of 88,868 AF per quarter from the second quarter of 2015 to the second quarter of 2017, including Class II injection wells, produced water for EOR and other oil field purposes, well stimulation fluids and water from other sources. An average of 1,550 AF per quarter of the total injected volume was reported as suitable for domestic or irrigation use.

Table 4.17-EE: Volume of Injection and Portion Suitable for Domestic or Irrigation Use Senate Bill 1281 Quarterly State Water Use Reports (acre feet)

	Total	**Portion Suitable for Domestic or Irrigation Use**
2015 Q1 (partial coverage)	41,402	292
2015 Q2	69,947	1,415
2015 Q3	93,110	1,735
2015 Q4	94,602	2,013
2016 Q1	93,048	1,477
2016 Q2	91,255	1,686
2016 Q3	92,802	1,107

Table 4.17-EE: Volume of Injection and Portion Suitable for Domestic or Irrigation Use Senate Bill 1281 Quarterly State Water Use Reports (acre feet)

	Total	**Portion Suitable for Domestic or Irrigation Use**
2016 Q4	87,978	1,404
2017 Q1	88,751	1,711
2017 Q2	88,316	1,403
Quarterly Average	88,868	1,550

Key:
AF = acre-feet
Q = quarter

Table 4.17-FF summarizes the quarterly volume of storage and non-injection fluids, and storage and non-injection water, reported to be suitable for domestic and irrigation use, and sources of storage and non-injection water other than produced water or Class II and well stimulation fluids from the second quarter of 2015 to the second quarter of 2017. Table 4.17-FF indicates that state oil and gas operators reported an average of 4,944 AF of storage and non-injection fluids per quarter, including Class II injection and well stimulation fluids, produced water, and water from other sources. An average of 641 AF per quarter of the total storage and non-injection water volume was suitable for domestic or irrigation use.

Table 4.17-FF: Volume of Storage and Non-Injection Fluids and Portion Suitable for Domestic or Irrigation Use Senate Bill 1281 Quarterly State Water Use Reports

	Total	**Portion Suitable for Domestic or Irrigation Use**
2015 Q1 (partial coverage)	4,783	670
2015 Q2	6,085	1,341
2015 Q3	5,138	495
2015 Q4	4,986	527
2016 Q1	4,960	418
2016 Q2	4,370	505
2016 Q3	4,908	579
2016 Q4	4,766	467
2017 Q1	4,686	796
2017 Q2	4,758	614
Quarterly Average	4,944	641

Key:
AF = acre-feet
Q = quarter

Sustainable Groundwater Management Act

In 2014, California enacted the SGMA (Water Code Section 10720 et seq.). This act, and related amendments to California law, require that all groundwater basins designated as high- or medium-priority in the DWR California Statewide Groundwater Elevation Monitoring program and that are subject to critical overdraft conditions must be managed under a new GSP, or a coordinated set of GSPs, by January 31, 2020. High- and medium-priority basins that are not subject to critical overdraft conditions must be managed under a GSP by January 31, 2022. Where GSPs are required, one or more local GSAs must be formed to cover the basin and prepare and implement applicable GSPs. The SGMA does not apply to basins that are managed under a court-approved adjudication, or to low- or very low-priority basins.

A GSA has the authority to require registration of groundwater wells, measure and manage extractions, require reports and assess fees, and request revisions of basin boundaries, including establishing new subbasins. The preparation of a GSP by a GSA is exempt from CEQA. Each GSP must include a physical description of the covered basin, such as groundwater levels, groundwater quality, subsidence, information on groundwater–surface water interaction, data on historical and projected water demands and supplies, monitoring and management provisions, and a description of how the plan will affect other plans, including city and county general plans. The SGMA requires that a GSP ensure that, within 20 years after plan adoption, the following “undesirable results” are avoided:

- Chronic lowering of groundwater levels (not including overdraft during a drought, if a basin is otherwise managed);
- Significant and unreasonable reductions in groundwater storage;
- Significant and unreasonable seawater intrusion;
- Significant and unreasonable degradation of water quality;
- Significant and unreasonable land subsidence; and
- Surface water depletions that have significant and unreasonable adverse impacts on beneficial uses (Water Code Section 10721(w)).

The current status of SGMA regulatory requirements in the Project Area, including basin and subbasin priority designations, basin boundary modifications approved by the DWR, the formation of GSAs, the adoption of GSPs, and the adoption of the SGMA emergency regulations by the DWR in 2016, are discussed in detail in Section 4.9.3, Hydrology and Water Quality, Regulatory Setting, *including the Sustainable Groundwater Management Act and Produced Water Reuse for Agricultural Irrigation subsections,* and in Section 4.9.2, Environmental Setting, *SGMA Overview*.

Senate Bill 4 (Well Stimulation Water Use Disclosure)

Effective January 1, 2014, California adopted several new and amended provisions of the PRC and Water Code to regulate any oil or gas well stimulation activity designed to enhance oil or gas production or recovery by increasing the permeability of the geologic formation that contains hydrocarbon deposits. Well stimulation activities covered by the new legislation include hydraulic fracturing and acid well stimulation treatments. The legislation, commonly referred to as "SB 4," amended Sections 3213, 3215, 3236.5, and 3401 of, and added Article 3 to, Chapter 1 of Division 3 of the PRC, and added Section 10783 to the Water Code. SB 4 requires that CalGEM: (1) promulgate emergency interim and adopt permanent regulations regulating well stimulation treatments by January 2015 to take effect no later than July 1, 2015; (2) complete a statewide Environmental Impact Report on well stimulation treatments by July 2015; (3) complete an independent scientific study of well stimulation by January 2015; and (4) consult and reach formal agreements with other regulatory agencies to provide regulatory accountability for, and public transparency to, well stimulation treatments by January 2015. SB 4 also requires that the SWRCB develop model criteria for oil and gas–related groundwater monitoring by July 2015. The regulations, studies, and interagency agreements required by SB 4 are intended to regulate water quality and potential geological hazards that could be associated with well stimulation, such as earthquakes or ground instability resulting from bedrock fracturing or acidization.

The well stimulation regulations require that each well operator disclose, within 60 days after a well stimulation treatment is completed, information regarding the source, volume, composition, and disposition of well stimulation fluids, including, but not limited to, water sources, hydraulic fracturing fluids, acid well stimulation fluids, and flowback fluids (California Code of Regulations §1788). The disclosures are provided to CalGEM and must be available online in a format that allows for searching and aggregating the information. A well stimulation treatment report must also be filed with CalGEM, including any information concerning stimulation treatments that differ from what was anticipated in the well stimulation treatment design submitted to CalGEM under Section 1784(b) and whether the actual location of the well stimulation treatment differs from what was indicated in the well stimulation permit application. For additional information concerning SB 4 regulatory requirements and the CalGEM review process for this program, please see Section 4.9.3, Hydrology and Water Quality, Regulatory Setting.

Porter-Cologne Water Quality Control Act

The Porter-Cologne Water Quality Control Act authorizes regulation of California water rights and water quality by the SWRCB. This act also established nine RWQCBs to ensure that water quality on local/regional levels is maintained. The Project Area is under the jurisdiction of the CVRWQCB.

State Water Resources Control Board

NPDES was established per the 1972 amendments to the Federal CWA, to control discharges of pollutants from point sources (Section 402). Amendments to the CWA created a new section to CWA, which is devoted to stormwater permitting (Section 402[p]), with individual states designated for administration and enforcement of the provisions of the CWA and the NPDES permit program. The SWRCB issues individual permits under this program.

On November 6, 2018, the State Water Board amended the Industrial General Permit Order 2014-0057-DWQ as amended by Order 2015-0122-DWQ to incorporate the following requirements: 1. Federal Sufficiently Sensitive Test Method Ruling; 2. Total Maximum Daily Load Requirements; and, 3. Statewide Compliance Options incentivizing on-site or regional storm water capture and use.

California Regional Water Quality Control Board, Central Valley Region

The Central Valley Region is the State's largest RWQCB, encompassing 60,000 square miles, or about 40 percent of the State's total area. Thirty-eight of California's 58 counties are either completely or partially within the Regional Board's boundaries, formed by the crests of the Sierra Nevada range on the east, the Coast Ranges and Klamath Mountains on the west, the Oregon border on the north, and the Tehachapi Mountains on the south. Included are 11,350 miles of streams, 579,110 acres of lakes, and the largest contiguous groundwater basin in California. The Sacramento and San Joaquin Rivers, along with their tributaries, drain the major art of this large area through an inland Delta, prior to emptying into the San Francisco Bay.

Wastewater

General Waste Discharge Requirements for Sanitary Sewer Systems

The General WDRs for Sanitary Sewer Systems were adopted by the SWRCB in May 2006. These WDRs require local jurisdictions to develop a sewer system management plan (SSMP) that addresses the necessary operation and emergency response plans to reduce sanitary sewer overflows. The WDRs require that the local jurisdiction approve the SSMP.

California Water Code Section 13260

California Water Code Section 13260 requires any person who discharges waste, other than into a community sewer system, or proposes to discharge waste that could affect the quality of the waters of the State, to submit a report of waste discharge to the applicable Regional RWQCB. Any actions of the project that would be applicable under California Water Code Section 13260 would be reported to the Central Valley RWQCB.

Solid Waste

California Department of Resources Recycling and Recovery (formerly California Integrated Waste Management Board)

California Department of Resources Recycling and Recovery (CalRecycle) is the State agency designated to oversee, manage, and track California's 76 million tons of waste generated each year. It is one of the six agencies under the umbrella of the California Environmental Protection Agency. CalRecycle develops regulations to control and manage waste, for which enforcement authority is typically delegated to the local government. CalRecycle works jointly with local governments to implement regulations and fund programs.

California Integrated Waste Management Act (AB 939)

California adopted its first statewide, general recycling program in 1989. The Integrated Waste Management Act of 1989 (PRC 40050 et seq. or AB 939, codified in PRC 40000), administered by CalRecycle, requires all local and county governments to adopt a Source Reduction and Recycling Element to identify means of reducing the amount of solid waste sent to landfills. This law set reduction targets at 25% by the year 1995 and 50% by the year 2000.

Assembly Bill 341

AB 341 (Chesbro, Chapter 476, Statutes of 2011), approved by Governor Brown on October 5, 2011, established a new statewide goal of 75% recycling composting and source reduction by 2020. In contrast to earlier diversion mandates, disposal-related activities, including alternative daily cover, alternative intermediate cover, transformation, waste tire-derived fuel, and beneficial reuse at solid waste landfills, do not count toward the statewide recycling goal.

To achieve the 75% recycling goal, CalRecycle has identified six primary focus areas: (1) moving organics out of the landfill; (2) continuing reform of the Beverage Container Recycling Program; (3) expanding the recycling/manufacturing infrastructure; (4) exploring new models for state and local funding of materials management programs; (5) promoting state procurement of post-consumer recycled content products; and (6) promoting extended producer responsibility.

Oil and Gas-Related Wastewater Disposal

Federal, state, and local laws, regulations, and policies pertaining to the disposal of oil and gas-related produced water and other wastewater in the Project Area are discussed in detail in Section 4.9, Hydrology and Water Quality, Regulatory Setting.

Energy

California Energy Commission

The CEC is the state's primary energy policy and planning agency. Created by the legislature in 1974, the CEC has five major responsibilities: (1) forecasting future energy needs and keeping historical energy data; (2) licensing thermal power plants 50 megawatts or larger; (3) promoting energy efficiency through appliance and building standards; (4) developing energy technologies and supporting renewable energy; and (5) planning for and directing state response to energy emergencies. With the signing of the Electric Industry Deregulation Law in 1998 (AB 1890), the CEC's role includes overseeing funding programs that support public interest energy research, advancing energy science and technology through research, development, and demonstration, and providing market support to existing, new, and emerging renewable technologies.

California Public Utilities Commission

The California Public Utilities Commission (CPUC) regulates privately owned electric, telecommunications, natural gas, water, and transportation companies, in addition to household goods movers and rail safety. The CPUC is responsible for ensuring that customers have safe and reliable utility service at reasonable rates, protecting against fraud and promoting the health of California's economy.

Assembly Bill 1057

AB 1057 (Limón), approved by Governor Newsom on October 12, 2019, changed the name of the Division of Oil, Gas, and Geothermal Resources (DOGGR) within the department of Conservation to the Geologic Energy Management Division (CalGEM) and made conforming changes. This bill specifies that the purpose of provisions relating to oil and gas conservation include protecting public health and safety and environmental quality in a manner that meets the energy needs of the state. The bill requires the State Oil and Gas Supervisor to coordinate with other state agencies and entities to help support the state's clean energy goals.

This bill authorizes the division to require an operator filing an individual or blanket indemnity bond, as applicable, to provide an additional amount of security acceptable to the division based on the division's evaluation of the risk that the operator will desert its well or wells and the potential threats the operator's well or wells pose to life, health, property, and natural resources. Additionally, this bill requires, upon request of the supervisor, a former operator to provide certain additional information about the disposition to the division, as specified.

Similarly, upon request of the supervisor, a new operator may need to provide certain additional information about the disposition to the division, as specified. The bill requires the new operator, after notice of operations and until another person acquires the well or production facility, to notify the supervisor, in writing by July 1 every other year, whether any of the rights have changed, and within 30 days of any quitclaim of a well or production facility. A state-manded local program would be imposed because a violation of these provisions relating to providing additional information would be a crime.

California's Energy Efficiency Standards for Residential and Nonresidential Buildings (Title 24 Building Standards)

The CEC administers Title 24 Building Standards, which were first adopted in 1976 in response to a legislative mandate to reduce California's energy consumption. Standards are periodically updated to allow consideration and possible incorporation of new energy efficiency technologies and methods. California's building efficiency standards are updated on an approximately three-year cycle. The 2019 Building Standards focus on several key areas to improve the energy efficiency of newly constructed buildings and additions and alterations to existing buildings. The 2019 Building Standards went into effect on December 12, 2018, following approval of the California Building Standards Commission.

Local

Kern County General Plan

The Project Area is located within the Kern County General Plan (KCGP) area and, therefore, would be subject to applicable policies and measures of the KCGP. The Land Use, Conservation, and Open Space Element and the Energy Element of the KCGP includes goals, policies, and implementation measures related to utilities and service systems that apply to the Project, as described below.

Chapter 1. Land Use, Conservation, and Open Space Element

1.4. Public Facilities and Services

Goals

Goal 1. Kern County residents and businesses should receive adequate and cost effective public services and facilities. The County will compare new urban development proposals and land use changes to the required public services and facilities needed for the proposed project.

Goal 5. Ensure that adequate supplies of quality (appropriate for intended use) water are available to residential, industrial, and agricultural users within Kern County.

Goal 9. Serve the needs of industries and Kern County residents in a manner that does not degrade the water supply and the environment and protect the public health and safety by avoiding surface and subsurface nuisances resulting from the disposal of hazardous wastes, irrespective of the geographic origin of the waste.

Policy 1. New discretionary development will be required to pay its proportional share of the local costs of infrastructure improvements required to service such development.

Policy 3. Individual projects will provide availability of public utility service as per approved guidelines of the serving utility.

Implementation Measures

Implementation Measure C. Project developers shall coordinate with the local utility service providers to supply adequate public utility services.

Implementation Measure L. Prior to the approval of development projects, the County shall determine the need for fire protection services. New development in the County shall not be approved unless adequate fire protection facilities and resources can be provided.

Implementation Measure N. Secure complete and accurate information on all hazardous wastes generated, handled, stored, treated, transported, and disposed of within or through Kern County.

Implementation Measure O. Reduce to the greatest degree possible the amount of waste to be disposed of by encouraging private industry to construct and manage a high quality system of transfer stations, recycling facilities, treatment plants, and incinerators located near the generators of hazardous waste.

Implementation Measure R. Roads and highways utilized for commercial shipping of hazardous waste destined for disposal will be designated as such pursuant to Vehicle Code Sections 31303 et seq. Permit applications shall identify commercial shipping routes they propose to utilize for particular waste streams.

1.8 Industrial

Policies

Policy 1. Locations for new industrial activities shall be provided with adequate infrastructure (water, sewage disposal systems, roads, drainage, etc.) to minimize effects on County services.

5. Energy Element

5.3.3. Waste Disposal in Petroleum Development

Goals

Goal, To encourage the safe recycling, transportation, and disposal of wastes associated with petroleum production and processing and to provide for the siting of disposal facilities in locations with proper access, while minimizing adverse impacts on the environment and on public health and safety.

Policies

Policy 1, The County shall continue to acknowledge the necessity to site nonhazardous oilfield waste disposal sites near petroleum development to minimize transportation hazards and expenses, consistent with the provisions of the Kern County and Incorporated Cities Integrated Waste Management Plan.

Policy 2, The County shall encourage recycling and new treatment methods for hazardous and nonhazardous oilfield wastes.

Policy 3, The County shall work cooperatively with appropriate State and regional agencies to provide for the proper siting of oilfield waste disposal facilities.

Policy 4, The County shall address hazardous oilfield waste disposal issues in the Kern County and Incorporated Cities Hazardous Waste Management Plan policies and implementation measures.

Implementation Measures

Implementation Measure B, The County shall address oilfield hazardous waste issues through the Kern County and Incorporated Cities Hazardous Waste Management Plan.

Implementation Measure C, The County shall continue to maintain provisions in the Zoning Ordinance to provide for oilfield waste disposal facilities.

Implementation Measure D, The County shall continue to maintain provisions in the Zoning Ordinance for the development of oilfield waste recycling and treatment facilities.

Metropolitan Bakersfield General Plan

The Metropolitan Bakersfield General Plan (MBGP), a joint effort between the Kern County Planning and Natural Resources Department and the City of Bakersfield Planning Division, was last adopted on December 11, 2007. The MBGP includes both city and unincorporated County lands. The MBGP describes the community's physical development as well as its economic, social, and environmental goals and is currently undergoing an update. The Project Area includes a total of 152,040 acres of unincorporated County lands that are covered under the MBGP (7.41%). Project-related development on unincorporated lands within the MBGP Planning Area would be subject to the following applicable policies and implementation measures of the MBGP, with respect to utilities and service systems.

Chapter II. Land Use Element

Policies

Policy 54, The developer shall be responsible for all onsite costs incurred as a result of the proposed project, in addition to a proportional share of offsite costs incurred in service extension or improvements. The availability of public or private services or resources shall be evaluated during discretionary project consideration. Availability may affect project approval or result in a reduction in size, density, or intensity otherwise indicated in the general plan's map provisions.

Chapter X. Public Services and Facilities Element

A. General Utilities

Goals

Goal 4. Develop funding principles and programs which will assure that all new development will pay for the incremental costs of the public facilities and services--utilities bridges, parks, and public safety facilities--both onsite and offsite, to serve such development.

Policies

Policy 5. Require all new development to pay its pro rata share of the cost of necessary expansion in municipal utilities, facilities and infrastructure for which it generates demand and upon which it is dependent (I-3).

Implementation Measures

Implementation Measure 4. Create benefit assessment districts or establish service fees for the distribution of costs to users for capital improvement replacement costs and maintenance, utilizing such districts for the financing of improvements which are essential to planning area development.

B. Water Distribution

Goals

Goal 1. Ensure the provision of adequate water service to all developed and developing portions of the planning area.

Policies

Policy 3. Require that all new development proposals have an adequate water supply available (I-3, I-4).

Implementation Measures

Implementation Measure 3. Review, and modify as required, existing fee structures and ordinances to assure desired system financing and policy implementation.

C. Sewer Service

Goals

Goal 1. Ensure the provision of adequate sewer service to serve the needs of existing and planned development in the planning area.

Implementation Measures

Implementation Measure 6. Exclusive of County Service Area No. 71, developers shall be required to install dry sewer lines in streets and connections thereto for parcels less than 1 acre (net) in size in areas where a centralized sewer system is planned and imminent and where onsite systems can be proven to be temporarily satisfactory.

Within County Service Area No. 71, a proposed development at a density greater than one dwelling unit per three gross acres, as well as all commercial and industrial developments, shall be required to be served by a regional sewage collection and treatment system subject to the following provisions:

1. All new development (commercial, industrial and residential at densities greater than one dwelling unit per three gross acres}, including both discretionary and ministerial projects, shall be required to connect to public sewer when said development is located 1,000 feet or closer to available public sewer.

   If public sewer is more than 1,000 feet from development, a dry sewer system in conjunction with approved individual septic systems may be utilized for lots having an area of 10,000 square feet or larger. Dry sewer systems are not required for lots of three gross acres or larger.

Single residential lots that require a ministerial permit shall connect to public sewer when located 200 feet or closer to available public sewer. Single residential lots less than three gross acres that are greater than 200 feet from available public sewer are required to install dry sewer in accordance with the requirements of the Engineering and survey.

2. All new development (commercial, industrial and residential at densities greater than one dwelling unit per three gross acres), including both discretionary and ministerial projects, shall pay a sewer development fee where the Board of Supervisors has adopted a planned sewer area and install dry sewer within the project development when located in excess of 1,000 feet from public sewer or where sewer service is not available as determined by the Engineering and Survey Services Department. The fee amount shall be based on the property's pro rata share of all conveyance, facility and capacity costs. Single residential lots that are greater than 200 feet from available public sewer are required to install dry sewer in accordance with the requirements of the Engineering and Survey Services Department.
3. In those cases where sewer service will not be available as determined by the Sewer Master Plan, an exemption may be granted by the Engineering and Survey Services Department.
4. All new development (commercial, industrial, and residential at densities greater than one dwelling unit per three gross acres) shall be required to annex to an existing County Service Area (CSA) or form a new CSA if none is already in place. In conjunction with formation of, or annexation to, a CSA, applicants shall be required to form a Zone of Benefit for the purpose of constructing and maintaining a sewer trunk line.

D. Storm Drainage

Goals

Goal 1. Ensure the provision of adequate storm drainage facilities to protect planning area residents from flooding resulting from storm water excess.

Kern County Specific Plans

As of 2020, Kern County has adopted 37 Specific Plans for properties within the Project Area. These Specific Plans are intended to be an amplification of the goals and policies of the KCGP and are, therefore, consistent therewith. As depicted in Figure 4.10-3, less than 8% of the Project Area is located wholly or partially within adopted Specific Plan areas (see the 2015 FEIR Section 4.10, Land Use and Planning). Future oil and gas exploration and production activities that would be authorized under the proposed Amendment to Chapter 19.98 (Oil & Gas Production) of the Kern County Zoning Ordinance that would be regulated according to County zoning, with the exception of the Specific Plans identified as Tier 5.

Kern River Plan Element

The Kern River Plan Element, which is included in both the KCGP and the MBGP, includes implementation measures related to utilities and service systems. The plan was adopted in 1985 and includes implementation policies applicable to County land within the Kern River Plan Element area. These policies are outlined below.

3.2. Open Space Versus Development

Policies

Policy 11. New or relocated utility lines shall be placed underground, except in areas subject to intensive agricultural uses, areas designated as A.4 (Mineral and Petroleum) and electrical power lines to oil wells, water wells, and water control devises in areas designated as 8.5 (Resource Management) unless otherwise required by law, and at River crossings, or where it can be shown that the specific nature of the facility is such that it is entirely infeasible to do so.

5.3. Implementation Standards and Specific Policies

B. Open Space and Development

Implementation Policies

Implementation Policy 7. New or relocated utility lines shall be placed underground, except in areas subject to intensive agricultural uses, 8.4 areas (Mineral and Petroleum), and at River crossings or where it can be shown that the specific nature of the facility is such that it is entirely infeasible to do so.

Kern County and Incorporated Cities Hazardous Waste Management Plan

In 1991, Kern County and the incorporated cities adopted the Kern County and Incorporated Cities Hazardous Waste Management Plan, which was developed to comply with State Law (California Health and Safety Code Section 25135 et seq.). The Hazardous Waste Management Plan includes goals, policies, and implementation measures directed at the safe and responsible management of hazardous waste including waste stream management, source reduction, siting of new facilities, and other provisions. The safe management of hazardous waste is to be accomplished in accordance with federal, state and local laws.

4.17.4 Supplemental Recirculated Environmental Impact Report New and Updated Analysis

Methodology

The potential impacts associated with the Project were evaluated on a quantitative and qualitative basis and reflect consultations with public service providers in the Project Area. Public service systems were evaluated by reviewing the most current data available from State and Kern County department websites, the KCGP, the Kern County Multi-Hazard Mitigation Plan, water management plans adopted by Project Area water providers, an analysis of Project Area water supplies completed by Kennedy/Jenks (2015 FEIR Appendix T-1), and the Kern County Fire Department Wildfire Management Plan. New information considered in the SREIR analysis includes the adopted GSPs and Management Area plans and proposed SGMA Projects in the Project area, the KCS GSA Annual Report, the KCS Coordination Agreement and coordinated water budget analysis, the SB 1281 quarterly water use reports compiled and published by CalGEM since the first quarter of 2015, and the discussion of SGMA planning objectives and oil and gas activities in each GSP and Management Area plan adopted for the KCS *and in other portions of the Project Area* (see Section 4.9, Hydrology and Water Quality). The potential impacts associated with the proposed Project are evaluated on a quantitative and qualitative basis through coordination with the service agencies described above. *As described in Chapter 3, Project Description and in Section 4.9.2, Hydrology and Water Quality, Environmental Setting, Water Supply Baseline Update, and summarized in Section 4.17.2, Environmental Setting (above) the following analysis of potential Project water supply impacts discusses the Project Area, and each of the three subareas, which reflect the Project Area's primary hydrogeological conditions. The analysis further considers the extent to which oil and gas operations were identified as a significant factor affecting the achievement of SGMA objectives, including water supply and demand, in each GSP and management area plan adopted for any portion of the Project Area. None of the adopted GSPs and management areas plans within the Project Area identify oil and gas operations as a significant factor affecting the achievement of any of the SGMA objectives. Almost all of the GSPs and management area plans explicitly exclude oil and gas operational areas and exempted aquifers from SGMA-regulated groundwater basins. Several identify the potential use of treated and/or blended oil and gas produced water as a potential source of new imported water that would increase available supplies for agricultural irrigation purposes and reduce potential groundwater demand over time. For more information concerning the discussion of oil and gas activities in each adopted GSP and management area plan in the Project Area, see Section 4.9.2, Hydrology and Water Quality, Environmental Setting, Project Area Groundwater Sustainability Plans and Oil and Gas Activities and Appendix D of this SREIR.* The discussion below lists specific impacts and measures that would be incorporated to mitigate and reduce potential impacts, to the extent feasible.

Thresholds of Significance

The CEQA Appendix G Checklist and the NOP for this Project state that a project would have a significant impact on hydrology and water quality if it would:

- Require or result in the relocation or construction of new or expanded water, wastewater treatment or storm water drainage, electric power, natural gas, or telecommunications facilities, the construction or relocation of which could cause significant environmental effects.
- Have sufficient water supplies available to serve the project and reasonably foreseeable future development during normal, dry and multiple dry years.

- Result in a determination by the waste water treatment provider which serves or may serve the project that it has adequate capacity to serve the project's projected demand in addition to the provider's existing commitments.
- Generate solid waste in excess of state or local standards, or in excess of the capacity of local infrastructure, or otherwise impair the attainment of solid waste reduction goals.
- Comply with federal, State, and local management and reduction statutes and regulations related to solid waste.

Project Impacts

Impact 4.17-1: Exceed Wastewater Treatment Requirements of the Applicable Regional Water Quality Control Board

The analysis of the potential of the Project to exceed wastewater treatment requirements of the applicable regional water quality control board was assessed in Section 4.17 Utilities and Service Systems, of the 2015 FEIR (SREIR Volume 3). MM 4.9-1 to MM 4.9-6 from the 2015 FEIR Section 4.9, Hydrology and Water Quality continue to be required.

Mitigation Measures

Implement stormwater mitigation measures, as described in Section 4.9, Hydrology and Water Quality.

Level of Significance After Mitigation

Impacts would be less than significant after mitigation.

Impact 4.17-2: Require or result in the relocation or construction of new or expanded water, wastewater treatment or storm water drainage, electric power, natural gas, or telecommunications facilities, the construction or relocation of which could cause significant environmental effects.

The analysis of the potential of the Project to require or result in the relocation or construction of new or expanded water or wastewater treatment facilities, the construction or relocation of which could cause significant environmental effects was assessed in Section 4.17, Utilities and Service Systems, of the 2015 FEIR (SREIR Volume 3). As discussed in Impact 4.17-4, no new water facilities are required by feasible mitigation measures related to reducing water supply impacts. MM 4.17-1 from the 2015 FEIR continues to be required.

Mitigation Measures

MM 4.17-1 Prior to the issuance of building permits for an operations and maintenance building, the method of sewage disposal shall be as required and approved by the Kern County Public Health Services Department. Compliance with this requirement will necessitate that the Project proponent obtain the necessary approvals for the design of the septic system from the Kern County Engineering, Surveying and Permit Services Department. The septic system disposal field shall be located a minimum of 100 feet from a classified stream or 25 feet from a non-classified stream and shall not be located where it would impact State wetlands or special-status plant species.

Level of Significance After Mitigation

Impacts would be less than significant after mitigation.

Impact 4.17-3: Require or result in the relocation or construction of new or expanded water, wastewater treatment or storm water drainage, electric power, natural gas, or telecommunications facilities, the construction or relocation of which could cause significant environmental effects.

The analysis of the potential of the Project to result in the relocation or construction of new or expanded storm water drainage facilities, the construction or relocation of which could cause significant environmental effects, was assessed in Chapter 4.17, Utilities and Service Systems, of the 2015 FEIR (SREIR Volume 3). MM 4.9-1 from the 2015 FEIR continues to be required.

Mitigation Measures

Implement stormwater mitigation measures, as described in Section 4.9, Hydrology and Water Quality.

Level of Significance After Mitigation

Impacts would be less than significant after mitigation.

Impact 4.17-4: Have sufficient water supplies available to serve the project and reasonably foreseeable future development during normal, dry and multiple dry years

The following analysis of potential Project water supply impacts considers water supply and demand in the Project Area, within each of the three Project subareas, and the extent to which oil and gas operations were identified as a significant factor affecting the achievement of SGMA objectives, including water supply and demand, in each GSP and management area plan adopted for any portion of the Project Area. As discussed above and in 2015 FEIR Appendix T-1, based on the potential development of up to 2,697 new production wells per year, oil and gas exploration and production demand for produced water and M&I water would increase from existing levels. As shown in Table 4.17-26, oil and gas demand for produced water is projected to increase by 32,600 AFY, and M&I demand is projected to increase by about 2,982 AFY from 2012 levels by 2035. Produced water demand for agricultural reuse is projected to be 38,658 AFY.

Table 4.17-26: Produced Water and Oil and Gas M&I Water Demand 2012, 2015, and 2035

	2012 (AF)	2015 (AF)	2035 (AF)	Net Increase 2012–2035 (AF)	Percent Increase
Produced Water (oil and gas uses)	88,812	93,106	121,412	32,600	37%
Produced Water (agricultural reuse)	38,658	38,658	38,658	0	0%
Subtotal: Produced Water Demand	127,470	131,764	160,070	32,600	27%
Projected M&I Water Demand	8,778	9,660	11,760	2,982	34%

Source: 2015 FEIR Appendix T-1, Table 19, Table 30, and Table 39
Key:
AF = acre-feet
M&I = municipal and industrial

As discussed in Section 4.9, Hydrology and Water Quality, oil and gas exploration and production activities currently generate sufficient produced water to meet existing and future demands. About 234,959 AF of produced water was generated in 2012, and about 321,894 AF will be generated in 2035 if produced water volume increases at the same rate as projected oil and gas industry demand (37% increase during 2012 to 2035). About 49% of produced water was disposed of by injection or to surface ponds in 2012. As shown in Section 4.9, Hydrology and Water Quality, the percentage of surplus produced water subject to disposal in 2035 could range from 47% to 50%, depending on the potential reuse of these supplies for other purposes (see Table 4.9-27).

The amount of produced water generated in the Project Area in 2012 would exceed anticipated demand in 2035 for oil and gas and agricultural reuse (160,070 AF) by about 75,000 AF. As shown in Section 4.9, Hydrology and Water Quality, the volume of produced water, and the ratio of produced water to recovered hydrocarbons, have increased in the Project Area over time. As Project Area oilfields mature, it is likely that the volume of produced water, and the ratio of produced water to recovered hydrocarbons, would be comparable to or greater than 2012 levels. Consequently, Project Area produced water supplies can be expected to continue to exceed demand by a significant margin under future conditions, and produced water resources are sufficient to meet current and projected future produced water demand in the Project Area.

Oil and gas demand for M&I water is projected to increase by about 2,982 AFY from 2012 levels by 2035 (see Table 4.17-26). The 2015 FEIR assumed that all oil and gas M&I demands will be met by using domestic and irrigation-quality groundwater. This is a conservative assumption because oil and gas M&I supply sources vary from year to year and may include surface supplies in wetter periods. The most recent drought severely restricted the availability of imported and local surface supplies throughout California, including the Project Area, and groundwater was used more heavily to meet Project Area demand, including for oil and gas activities. As discussed above and in 2015 FEIR Appendix T-1, surplus domestic and irrigation-quality water is not available in the Project Area. Any new use would reduce the availability of domestic and irrigation-quality water to another Project Area user, or increase the regional groundwater overdraft if supply shortfalls are addressed by increased groundwater extraction. Consequently, increasing oil and gas M&I water demand is considered to be a significant water supply impact.

Tables 4.17-27 to 4.17-29 summarize Project Area urban, agricultural, and oil and gas supply and demand in the Project Area and for each Subarea, over 2015 to 2035 under average, single dry year, and multiple dry year conditions as considered in the 2015 FEIR. The estimated supply and demand in each projection incorporate the assumptions discussed in Section 4.17.2, Environmental Setting.

Table 4.17-27 shows that, under average year conditions, water supply in the Project Area is approximately the same as the total demand, although the margin of supply relative to demand would diminish over time. Due to significant agricultural activity and related irrigation demand, the Central Subarea has a supply deficit in average years ranging from -681,596 AF in 2015 to -717,682 AF in 2035. Surpluses in the Eastern Subarea, generally associated with the availability of diverted water from the Kern River, and smaller average year surpluses in the Western Subarea slightly exceed the supply deficits in the Central Subarea.

Table 4.17-27: Project Area and Subarea Average Year Water Demand and Supply 2015 to 2035

	2015 (AF)	2020 (AF)	2025 (AF)	2030 (AF)	2035 (AF)
Project Area					
Supply	3,157,881	3,165,137	3,172,393	3,179,649	3,186,904
Demand	3,008,482	3,016,310	3,043,669	3,073,050	3,103,596
Difference (supply - demand)	148,399	148,827	128,724	106,599	83,308
Western Subarea					
Supply	1,041,993	1,047,065	1,052,136	1,057,208	1,062,279
Demand	981,984	987,370	992,761	998,157	1,003,561
Difference (supply - demand)	60,009	59,695	59,375	59,051	58,718
Central Subarea					
Supply	736,991	737,103	737,216	737,328	737,441
Demand	1,418,587	1,420,422	1,430,889	1,442,536	1,455,123
Difference (supply - demand)	-681,596	-683,319	-693,673	-705,208	-717,682
Eastern Subarea					
Supply	1,378,897	1,380,969	1,383,041	1,385,113	1,387,184
Demand	607,911	608,518	620,019	632,357	644,912
Difference (supply - demand)	770,986	772,451	763,022	752,756	742,272

Source: 2015 FEIR Appendix T-1.
Key:
AF = acre-feet

Table 4.17-28 shows that, under single dry year conditions, when surface supplies from the SWP, CVP, and Kern River systems would be substantially reduced, significant supply deficits would occur in the Project Area, the Central Subarea, and the Western Subarea. Project Area supply deficits in single dry years would range from -750,710 AF in 2015 to -817,127 AF in 2035. Supply deficits in the Central Subarea would exceed -950,000 AFY, and range from -12,989 to -14,320 AFY in the Western Subarea. Surpluses in the Eastern Subarea would be unable to offset the deficits projected in the Central and Western Subareas.

Table 4.17-28: Project Area and Subarea Single Dry Year Water Demand and Supply 2015 to 2035

	2015 (AF)	2020 (AF)	2025 (AF)	2030 (AF)	2035 (AF)
Project Area					
Supply	2,255,681	2,262,937	2,270,193	2,277,449	2,284,704
Demand	3,006,391	3,015,514	3,042,583	3,071,672	3,101,831
Difference (supply - demand)	-750,710	-752,577	-772,390	-794,223	-817,127
Western Subarea					
Supply	971,693	976,765	981,836	986,908	991,979
Demand	984,682	990,078	995,479	1,000,885	1,006,299
Difference (supply - demand)	-12,989	-13,313	-13,643	-13,977	-14,320
Central Subarea					
Supply	462,791	462,903	463,016	463,128	463,241
Demand	1,415,341	1,418,364	1,428,641	1,440,098	1,452,461
Difference (supply - demand)	-952,550	-955,461	-965,625	-976,970	-989,220
Eastern Subarea					
Supply	821,197	823,269	825,341	827,413	829,484
Demand	606,368	607,072	618,463	630,689	643,071
Difference (supply - demand)	214,829	216,197	206,878	196,724	186,413

Source: 2015 FEIR Appendix T-1.
Key:
AF = acre-feet

Table 4.17-29 shows that, under multiple dry year conditions, when surface supplies would be reduced below average year levels, significant supply deficits would occur in the Project Area and the Central Subarea. Project Area supply deficits in multiple dry years would range from -315,626 AF in 2015 to -383,042 AF in 2035. Central Subarea supply deficits would range from -772,009

AF in 2015 to -808,789 AF in 2035. Surpluses in the Eastern Subarea and Western Subarea would be unable to offset the deficits projected in the Central Subarea.

Table 4.17-29: Project Area and Subarea Multiple Dry Year Water Demand and Supply 2015 to 2035

	2015 (AF)	2020 (AF)	2025 (AF)	2030 (AF)	2035 (AF)
Project Area					
Supply	2,695,681	2,702,937	2,710,193	2,717,449	2,724,704
Demand	3,011,307	3,020,223	3,047,664	3,077,155	3,107,746
Difference (supply - demand)	-315,626	-317,286	-337,471	-359,706	-383,042
Western Subarea					
Supply	1,053,993	1,059,065	1,064,136	1,069,208	1,074,279
Demand	984,486	989,881	995,281	1,000,686	1,006,100
Difference (supply - demand)	69,507	69,184	68,855	68,522	68,179
Central Subarea					
Supply	643,891	644,003	644,116	644,228	644,341
Demand	1,415,900	1,418.901	1,429,219	1,440,720	1,453,130
Difference (supply - demand)	-772,009	-774,898	-785,103	-796,492	-808,789
Eastern Subarea					
Supply	997,797	999,869	1,001,941	1,004,013	1,006,084
Demand	610,921	611,441	623,164	635,749	648,516
Difference (supply - demand)	386,876	388,428	378,777	368,264	357,568

Source: 2015 FEIR Appendix T-1.
Key:
AF = acre-feet

As discussed in Section 4.17.2, Environmental Setting, the 2019 DCR indicates that SWP delivery reliability may be slightly lower than considered in the 2015 FEIR, particularly in dry and multiple dry years (CNRA 2019). In addition, a May 2020 report on the CVP system by the Congressional Research Service indicates that CVP operations are subject to as yet unresolved species protection, stream flow, and state and federal coordination challenges. Consequently, regional water supplies from surface water may be slightly lower than considered in the 2015 FEIR. Under these circumstances, the extent to which such supplies could meet normal year demand would be reduced, and the single dry and multiple dry year supply deficits would be greater than projected in the 2015 FEIR and 2015 FEIR Appendix T-1.

Oil and gas exploration and production water use in the Project Area accounts for a relatively small portion of overall demand and higher-quality domestic and irrigation water consumption in the Project Area. The 2015 FEIR estimated that oil and gas total water use, including produced water demand and supply, would be about 3.4% of total Project Area water demand and supply in 2015. Oil and gas water demand would account for 4.3% of total Project Area water use in 2035 (see Table 4.17-30).

Table 4.17-30: Total Project Area and Oil and Gas in Average, Single Dry, and Multiple Dry Years, 2015 and 2035

	Average Year (AF)	**Single Dry Year (AF)**	**Multiple Dry Year (AF)**
2015			
Project Area Demand	3,008,482	3,006,391	3,011,307
Oil and Gas M&I Demand	9,660	9,660	9,660
Oil and Gas Produced Water Demand	93,106	93,106	93,106
Subtotal: Oil and Gas Water Demand	102,766	102,766	102,766
Oil and gas share of total Project Area demand	3.4%	3.4%	3.4%
2035			
Project Area Demand	3,103,596	3,101,831	3,107,746
Oil and Gas M&I Demand	11,761	11,761	11,761
Oil and Gas Produced Water Demand	121,412	121,412	121,412
Subtotal: Oil and Gas Water Demand	133,173	133,173	133,173
Oil and gas share of total Project Area demand	4.3%	4.3%	4.3%

Sources: See Tables 4.17-20 and 4.17-27 to 4.17-29
Key:
AF = acre-feet
M&I = municipal and industrial

Most of the oil and gas demand in the Project Area is met by using produced water. As shown in Table 4.17-31, excluding produced water supply and demand, oil and gas M&I water use would account for about 0.34% of total Project Area domestic and irrigation water demand in 2015. In 2035, oil and gas M&I demand would account for 0.40% of total Project Area domestic and irrigation water demand.

Table 4.17-31: Total Project Area and Oil and Gas Municipal and Industrial and Agricultural Water Demand (Excluding Produced Water Supplies and Demand) Average, Single Dry, and Multiple Dry Years, 2015, and 2035

	Average Year (AF)	Single Dry Year (AF)	Multiple Dry Year (AF)
2015			
Project Area Demand	2,867,058	2,864,967	2,869,883
Oil and Gas M&I Demand	9,660	9,660	9,660
Oil and gas share of total urban and agricultural demand	0.34%	0.34%	0.34%
2035			
Project Area Demand	2,931,765	2,930,000	2,935,915
Oil and Gas M&I Demand	11,761	11,761	11,761
Oil and gas share of total urban and agricultural demand	0.40%	0.40%	0.40%

Sources: See Tables 4.17-20 and 4.17-27 to 4.17-29
Key:
AF = acre-feet
M&I = municipal and industrial

Excluding the use of produced water, current and projected oil and gas M&I water demand is about 4% of total urban water use in the Project Area. As shown in Table 4.17-32, oil and gas M&I water use would account for about 4.03% to 4.11% of total Project Area urban demand in 2015 in normal, dry, and multiple dry years. In 2035, oil and gas demand would account for 3.84% to 3.92% of total Project Area urban water demand depending on hydrologic conditions.

Table 4.17-32: Total Project Area and Oil and Gas Municipal and Industrial and Urban Water Demand in Average, Single Dry, and Multiple Dry Years, 2015 and 2035

	Average Year (AF)	Single Dry Year (AF)	Multiple Dry Year (AF)
2015			
Project Area Urban Demand	237,029	234,938	239,854
Oil and Gas M&I Demand	9,660	9,660	9,660
Oil and Gas % of Total Urban Demand	4.08%	4.11%	4.03%
2035			
Project Area Urban Demand	301,736	299,971	305,886
Oil and Gas M&I Demand	11,761	11,761	11,761
Oil and Gas % of Total Urban Demand	3.90%	3.92%	3.84%

Sources: See Tables 4.17-20 and 4.17-27 to 4.17-29
Key:

AF = acre-feet
M&I = municipal and industrial

Oil and gas M&I demand is expected to increase by 2,100 AF per year from 2015 to 2035, while urban demand is projected to increase from 64,707 to 66,032 AF from 2015 levels, depending on hydrologic conditions. As shown in Table 4.17-33, oil and gas M&I demand would amount to 3.18% to 3.25% of the net increase in urban M&I demand in the Project Area during 2015 to 2035. Projected oil and gas M&I demand would increase by about 2,310 AFY during 2015 to 2035, including a 10% contingency (see Table 4.17-20), and would amount to 3.5% to 3.57% of the net increase in urban M&I demand in the Project Area during 2015 to 2035.

Table 4.17-33: Project Area Urban and Oil and Gas Municipal and Industrial Water Net Demand Increase, 2015 to 2035 Average, Single Dry, and Multiple Dry Years

	Average Year (AF)	**Single Dry Year (AF)**	**Multiple Dry Year (AF)**
Project Area Urban Demand Increase	64,707	65,033	66,032
Oil and Gas M&I Demand Increase	2,100	2,100	2,100
Oil and Gas/Urban Demand Increase	3.25%	3.23%	3.18%

Sources: See Tables 4.17-20 and 4.17-27 to 4.17-29
Key:
AF = acre-feet
M&I = municipal and industrial

Oil and gas M&I water demand represents a relatively small share of total Project Area domestic and irrigation water use, excluding produced water supply and demand (see Table 4.17-30). The projected growth in oil and gas M&I water demand, however, would require the development of new or expanded M&I-quality entitlements in a region for which the 2015 FEIR determined that existing and projected future supplies would be inadequate to meet demand under dry and multiple dry year conditions, even assuming the maintenance of historical groundwater extraction levels. Under these conditions, oil and gas M&I water use would compete with other M&I demands for supplies that are not expected to be readily available in the Project Area. A commensurate increase in groundwater extraction would be required to meet M&I demand if other supply sources are constrained, including due to the factors identified in the 2019 DCR and the 2020 Congressional Research Service report on the CVP. The impacts to domestic and irrigation-quality water supplies in the Project Area would be significant at the Project level, and oil and gas water demand would also contribute to significant cumulative impacts to regional water supplies in the Project Area.

As discussed in Section 4.9.2, Hydrology and Water Quality, Environmental Setting, small portions of the GSPs adopted for the Tule subbasin, the Tulare Lake subbasin, and the Cuyama Valley basin *extend into the Project Area. These GSPs primarily address groundwater basins that are almost entirely outside the Project Area. None of the small portions of these GSPs that extend into the Project Area underlie an existing administrative oil field boundary or an oil and gas core area. A review of the applicable GSPs for these basins did not identify significant references to oil and gas activity, including domestic or irrigation quality groundwater use, that could affect sustainable groundwater management in the relevant plan areas. A small portion of the low-priority Carizzo Plain basin in the southwest portion of the Project Area, which does not require a GSP, also does not underlie an existing administrative oil field boundary or a core area. No GSA has been formed or GSP adopted for this basin, and there is no new substantial evidence that oil and gas activity, including domestic or irrigation quality groundwater use, would affect groundwater conditions in this basin.*

A portion of the low-priority Kettleman Plain subbasin in the northeast portion of the Project Area, which does not require a GSP, underlies a small amount of existing administrative oil fields and Core Areas in the Project Area. Oil and gas activity in the subbasin has occurred for decades. No GSA has been formed or GSP adopted for this subbasin, and there is no new substantial evidence that oil and gas activity, including domestic or irrigation quality groundwater use, would affect groundwater conditions in this basin.

The White Wolf subbasin was separated from the KCS in a basin boundary modification approved by the DWR in 2016. The technical study prepared in support of the boundary modification indicates that the White Wolf subbasin had an approximate water inflow of 32,000 AFY, an outflow of about 28,500 AFY, and a net positive change in groundwater storage of 3,500 AFY. The technical study noted that oil and gas activities have historically occurred and continue to occur in the subbasin, including the production of 160,000 barrels of oil and 860,000 million cubic feet of gas production in 2014 (EKI 2016). The DWR reduced the basin's priority to medium from the high priority and critically overdrafted designations applicable prior to the approved basin boundary modification. A GSP for the White Wolf subbasin is not required until January 31, 2022. No GSP has been adopted for the White Wolf subbasin, and there is no new substantial evidence that oil and gas activity would significantly affect water supply and demand conditions in this basin.

Five GSPs, and 15 management area plans within the KGA GSP, have been adopted for the KCS, which includes about 1.8 million acres, underlies a significant portion of the Project Area, and accounts for the vast majority of the groundwater resources in the Project Area. The GSPs and management area plans provide detailed information about discrete areas within the KCS that have been managed by established water districts, or groups of water districts and other agencies, that have significant knowledge of local groundwater conditions and management requirements within each plan area. The plans also include detailed information about groundwater in relevant locations within each of the three subareas of the Project Area and were prepared by professional geologists or professional engineers as required by the SGMA. The plans reflect the requirements of the Coordination Agreement executed by the KCS GSAs and the coordinated water budget prepared for the entire subbasin in accordance with SGMA and the SGMA regulations. The extent to which oil and gas operations were identified as a significant factor affecting the achievement of any of the SGMA objectives, including water supply and demand, was evaluated for each GSP and management area plan adopted for any portion of the Project Area. For more detailed information *concerning the discussion of oil and gas activities in each of these plans, see Section 4.9.2, Hydrology and Water Quality, Environmental Setting, Project Area Groundwater Sustainability Plans and Oil and Gas Activities, and Appendix D of this SREIR.*

The adopted GSPs and Management Area plans in the Project Area provide additional substantial evidence that oil and gas activities involving the extraction, use, and disposal of produced water occur outside of and would not significantly affect Project Area domestic and irrigation-quality water supply sources. The GSPs and Management Area plans specifically exclude locations where producible hydrocarbons occur and exempted aquifers under the UIC program from the lateral and vertical boundaries of the groundwater subbasin in the KCS. The KGA GSP, which covers most of the Project Area subject to the SGMA and under the jurisdiction of the County, states that “active oil and gas aquifers and exempted aquifers are not a part” of the KCS “groundwater basin for beneficial use” (KGA 2020). The Annual Report published by the KCS GSAs refers to the use of produced water for domestic or irrigation purposes in the KCS as a “local imported” source of “surface water from local sources imported from areas outside of the Kern County Subbasin” (KCSGSAs 2020). The West Kern WD Management Area Plan states that “because the regulation of oil produced water under SGMA is not fully clear at this time” the “evaluation of oil produced water” will be reevaluated during the first five-year update the plan (Woodard & Curran 2019b). There is no substantial evidence that the exclusion of produced water from the sustainable groundwater management plans in the Project Area will be substantially modified in the future.

The GSPs and Management Area plans also exclude exempted aquifers from the sustainable groundwater management plans and sources of domestic and irrigation water in the Project Area. Several of the plans discuss the potential discharge of injection fluids into aquifers that have not been exempted under the UIC. Figure 2-39 of the KGAGSP (KGA 2020) and Figure 2-39 of the Henry Miller Water District GSP (Luhdorff & Scalmanini 2020) show the locations of 127 wells injecting in non-oil zones with TDS concentrations that are below 3,000 mg/L and 342 wells injecting in non-oil zones where TDS greater than 3,000 mg/L and less than 10,000 mg/L derived from a 2015 list provided by the state to the EPA in accordance with an ongoing aquifer exemption review work plan. The status of the work plan was updated in a letter from CalGEM to the EPA in March 2020, which indicates that from 2017 to 2020, the EPA approved 20 aquifer exemptions, including several within the Project Area and encompassing many of the wells identified in the GSPs (CalGEM 2020). Several other aquifer exemption proposals are being reviewed and considered by CalGEM, including locations in the Project Area (CalGEM 2020). The March 2020 CalGEM letter states that the ongoing implementation of the aquifer exemption work plan “continues to demonstrate the State’s commitment to protecting public health and the environment while avoiding unnecessary disruption of oil and gas production” (CalGEM 2020). A lawsuit against the aquifer exemption work plan was dismissed in 2016 by the California Superior Court, and the decision was upheld by the California Court of Appeals in 2018 (*Ctr. for Biological Diversity v. Cal. Dep't of Conservation*, (2018) 26 Cal. App. 5th 161). There is no substantial evidence that oil and gas activities related to the ongoing aquifer exemption work plan would cause significant new or significantly greater impacts to water supply in the Project Area than those considered in the 2015 FEIR.

The GSPs and Management Area plans adopted in the Project Area, and the coordinated water budget required by the SGMA, provide quantified water demand estimates and projections for urban uses based on data concerning per capita water use, and agricultural demand based on evapotranspiration and crops in the Project Area. None of these sources provide new information concerning the amount of oil and gas industry domestic and irrigation-quality water use. The Annual Report and the coordinated water budget indicate that oil and gas industry demand is included in the estimates of urban water use. The Westside District Water Authority Management Area Plan states that a "small portion of the SWP surface water supply mainly used for agriculture in the GSA is sometimes delivered as industrial water to agricultural processors and oil field production customers" and that "a percentage of the annual allocation from the SWP is delivered for industrial use in oil recovery operations in the North and South Belridge oil fields" (Aquilogic 2019). Most of the other GSPs and Management Area plans do not include significant discussion of the provision of water for oil and gas use. The quarterly water use reports published by CalGEM indicate that from the second quarter of 2015 to the second quarter of 2017, the period for which state data reviewed and compiled by CalGEM were available, statewide oil and gas use of domestic and irrigation-quality water for injection purposes averaged 1,550 AF per quarter and 641 AF were used for noninjection and storage purposes. These data indicate that, over four quarters, the use of domestic and irrigation-quality water by the state's oil and gas operations averaged about 8,764 AFY. The CalGEM quarterly water use reports cover 90 percent of the state, and oil and gas production in the Project Area accounts for about 80 percent of total California production. There is no substantial evidence that oil and gas use of domestic and irrigation-quality water in the Project Area would cause significant new or significantly greater impacts to water supplies than those considered in the 2015 FEIR.

In contrast with water demand, new information available since 2015 provides substantial evidence that oil and gas activities could enhance water supplies in the Project Area to a greater extent than considered in the 2015 FEIR. As discussed in Section 4.17.2, a coordinated water budget for the KCS covering a 50-year planning and implementation horizon from 2021 to 2070 has been prepared by the KCS GSAs in accordance with the SGMA regulations. The water budget considers water supply and demand in the KCS under baseline, climate change 2030, and climate change 2070 scenarios. The scenarios utilize sequences of drier and wetter water years that are representative of historical average conditions in the KCS and include varying assumptions concerning surface water supplies in response to regulatory and climate change impacts over time. The coordinated water budget compares the average annual change in KCS stored groundwater during the SGMA sustainability period of 2041 to 2070 with historical changes and with and without the implementation of SGMA Projects to enhance the subbasin's water budget. The coordinated water budget indicates that KCS groundwater in storage declined by an average of approximately -277,000 AFY during 1995 to 2014. The annual decline in stored groundwater would increase in each of the three scenarios without the SGMA Projects to an annual average of -324,326 in the baseline scenario, -380,900 in the climate change 2030 scenario, and -489,828 in the climate change 2070 scenario during 2041 to 2070. *As discussed in Section 4.9.2, Hydrology and Water Quality, Environmental Setting, SGMA Overview, the SGMA requires that each GSP and management area plan adopted in the KCS use the same information for the basin as a whole, including the water budget. Several of the KCS GSPs and management area plans provide a water* *budget for the applicable planning area that covers the same a 50-year planning and implementation horizon from 2021 to 2070, and is based on the same analysis, as the basin-wide water budget required by the Coordination Agreement.*

The adopted GSPs and Management Area plans identify multiple SGMA Projects that would improve the KCS water budget by approximately 421,000 AFY over the 50-year SGMA planning and implementation period. Several of the SGMA Projects consider the expanded use of produced water to enhance available supplies in the KCS. As discussed above, the GSPs and Management Area plans in the Project Area exclude produced water from the sustainable groundwater management plans. The Annual Report refers to produced water used for domestic or irrigation purposes as a local surface water imported supply. As a result, projects that expand the availability of produced water for domestic or irrigation use increase the net water supply in the Project Area. Proposed SGMA Projects that would increase the use of produced water in the Project Area include the following:

- Reclamation of oilfield produced water to develop new supplies estimated at 1,000 AFY in the Arvin-Edison Water Storage District Management Area Plan (EKI Environment & Water 2019a).
- Potential development of 7,000 to 20,000 AFY of new produced water supplies in the Cawelo GSA Management Area Plan (Cawelo GSA 2019).
- Construction of a pipeline for conveyance and blending of up to 3,000 AFY of new produced water supplies in the Kern-Tulare Water District Management Area Plan (KTWD 2019).
- Recycling oilfield produced water for agricultural use in the Eastside Water Management Area Plan (EKI Environment & Water 2019b).
- Potential treatment and use of up to 50,000 AFY of brackish groundwater and produced water for beneficial reuse in two construction phases over 10 to 20 years in the Westside District Water Authority Management Area Plan (Aquilogic 2019).

The coordinated water budget indicates that implementation of the SGMA Projects will result in an average annual change in stored KCS groundwater of +42,000 AFY in 2041 to 2070 in the baseline scenario, which increases to +85,578 AFY when adjusted for excess basin outflows. The average annual change in groundwater storage in the 2030 climate change scenario with the SGMA Projects will improve to -12,861 AFY during 2041 to 2070 and increase to +46,829 AFY when adjusted for excess outflows. The average annual change in groundwater storage in the 2070 climate change scenario will improve to -118,273 AFY during the 2041–2070 compliance period and further decline to -45,969 AFY when adjusted for excess outflows. The coordinated water budget provides substantial evidence that the availability and reuse of produced water from oil and gas operations would increase water supply in the Project Area if the SGMA Projects proposing to increase produced water reuse were successfully implemented during the 50-year SGMA planning and implementation horizon.

Produced water has historically been used in the Project Area, mainly for irrigation. This use is discussed in several of the GSPs and Management Area plans for the KCS, including the Cawelo GSA Management Area Plan, the Kern-Tulare Water District Management Area Plan and in the North Kern Water Storage District - Shafter-Wasco Irrigation District Management Area Plan. The quarterly water use reports for state oil and gas operators published by CalGEM indicate that from the second quarter of 2015 to the second quarter of 2017 California oil and gas operators sold or transferred an average of 8,991 AF of produced water per quarter for domestic use *as defined by CalGEM, which means that the "water is used for agriculture, irrigation, water replenishment, water banking, livestock, etc."* (CalGEM 2019a*; DOGGR 2018*). These data indicate that, over four quarters, the average sale or transfer of produced water for domestic and irrigation use was about 35,964 AFY. As noted above, the CalGEM quarterly water use reports cover 90 percent of the state, and oil and gas production in the Project Area accounts for about 80 percent of total California production.

The new information in the coordinated water budget and descriptions of the SGMA Projects in applicable GSPs and Management Area plans suggest that oil and gas activities could provide sufficient new supplies over the 50-year planning and implementation horizon required by the SGMA regulations to offset the industry's anticipated use of domestic and irrigation-quality water. Under these conditions, oil and gas activities would have a positive impact on Project Area water supplies and no mitigation measures would be required.

However, as discussed in Section 4.9.3, Regulatory Setting, subsection Produced Water Reuse for Agricultural Irrigation, several factors could constrain the use of produced water for irrigation. As discussed in Section 4.9.2, Hydrology and Water Quality, Environmental Setting, SGMA Overview, the plans are specifically intended to be adaptively managed in response to continual basin monitoring and analysis, including the development of new measures if necessary, and management that would address potentially significant social and economic harm in addition to meting SGMA objectives. The terms of the SGMA provide the GSAs with a 20-year period, including the periodic reassessment and modification of applicable GSPs and management area plans, to comply with the Act. ~~t~~*T*he SGMA Projects are proposed approaches for avoiding undesirable results in conjunction with long-term sustainable groundwater management plans that will be adaptively managed and modified as required to address changing conditions. It is possible that the additional produced water reuse discussed in the GSPs and Management Area plans, or other SGMA Projects that may be proposed for produced water reuse in the future, will prove to be technologically or economically infeasible. Several of the GSPs and Management Area plans include feasibility studies to assess these issues, including the Arvin-Edison Water Storage District Management Area Plan, the Cawelo GSA Management Area Plan, and the Westside District Water Authority Management Area Plan. As discussed in Section 4.17.2, oil and gas operations in the Project Area are significantly influenced by regulatory and global market factors and have varied substantially from 2014 to 2020. The Cawelo GSA Management Area Plan, which includes a portion of the Project Area where produced water has historically been used for irrigation, states that "[t]he volume of treated produced water will fluctuate with oil production and long-term availability cannot be predicted" (Cawelo GSA 2019). Produced water reuse considered by applicable GSPs and Management Area plans through 2070 would not occur if oil and gas operations significantly contract, as certain state regulators have advocated, over this period. There is also substantial evidence of ongoing opposition to treated produced water reuse based on perceived health and safety concerns, as discussed *the CVRWQCB draft Food Safety Project report (CVRWQCB 2019) and* in a peer-reviewed study published in May 2020 by researchers from Duke University and RTI International (Duke University 2020). Although *the CVRWQCB and SWRCB have not found any evidence of elevated health and safety risks from the use of produced water for irrigation in accordance with applicable permits and approvals, and* the study determined that produced water reuse did not result in salts, metals, and naturally occurring radioactive materials contamination in the CWD, it is reasonably foreseeable that perceived health and safety concerns may result in continued opposition to treated produced water reuse in the Project Area. Consequently, while it is possible that oil and gas operations will generate a net increase in domestic and irrigation quality water as the SGMA is implemented in the Project Area, it is also possible that the supply of treated produced water will be curtailed by regulatory and economic factors. There is no substantial evidence that expanded treated produced water reuse will occur in the Project Area in predictable volumes over time.

Consequently, while it is possible that oil and gas operations will generate a net increase in domestic and irrigation-quality water as the SGMA is implemented in the Project Area, it is also possible that the supply of produced water will be curtailed due to regulatory or economic factors, or that such reuse will be technologically, economically or environmentally infeasible. There is no substantial evidence that produced water will continue to be utilized or that expanded produced water reuse will occur in the Project Area in predictable volumes over time. As a result, the projected increase in the oil and gas industry's domestic and irrigation-quality water use of 8,774 AFY to 11,761 AFY represents the potential impact to water supply attributable to the Project. Due to the unavailability of surplus water in the Project Area, which is also demonstrated by the increasingly negative changes in the annual amount of stored groundwater projected for 2021 to 2070 without the SGMA Projects in the KCS coordinated water budget, oil and gas consumption of domestic and irrigation-quality water would have a significant impact and contribute to a significant cumulative impact to water supplies in the Project Area.

CEQA requires that the lead agency identify feasible mitigation measures to reduce impacts determined to be significant. Under CEQA, mitigation is feasible if it is capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social, and technological factors.

The 2015 FEIR determined that no feasible mitigation could reduce significant water supply impacts to less than significant levels. Three mitigation measures in the 2015 FEIR MM 4.17-2 to 4.17-4, were identified to reduce significant impacts, primarily by encouraging greater produced water reuse and reduced domestic and irrigation water use by oil and gas operators. As discussed in Chapter 3.1.1, Revisions to Title 19 - Kern County Zoning Ordinance (2020-A) and Related Changes, the Appellate Court determined that these mitigation measures violated CEQA because they did not require or result in predictable oil and gas domestic and irrigation-quality water use reductions, and because they did not provide the provide the County Board of Supervisors with sufficient information concerning the net impact to groundwater and water supplies when the Board adopted a Statement of Overriding Considerations for these impacts.

As discussed in Section 4.9.2, Hydrology and Water Quality, Environmental Setting, the County withdrew from the KGA in 2018 and does not participate in the SGMA management of the Project Area. *As discussed in Section 4.9.2, Hydrology and Water Quality, Environmental Setting, SGMA Overview, the SGMA presumes that* GSAs in the Project Area ~~*have*~~ *are the* exclusive *local agencies* for ~~*sustainable groundwater management*~~ *implementing the SGMA in accordance with duly adopted GSPs. The adopted GSPs and management area plans state that each plan reflects this exclusive jurisdiction, and the KGA GSP further provides that the member agencies in the KGA GSA have the sole responsibility for implementing the SGMA within each management plan area.* ~~*under the SGMA*~~ *The SGMA provides the GSAs with regulatory authority to implement several actions, including potential regulation of groundwater withdrawals from individual wells or all wells in an entire basin. The SGMA further requires that each GSA develop GSPs and management area plans that consider the interests of all beneficial uses and users of groundwater, as well as those responsible for implementing GSPs and including surface water users, if there is a hydrologic connection between surface and groundwater bodies. In basins and subbasins like the KCS, where multiple GSAs have been formed and multiple GSPs and management area plans have been adopted, the SGMA requires that the GSAs implement the applicable plans in accordance with a coordination agreement that will result in a comprehensive, sustainable management solution for the entire basin or subbasin. The SGMA requires that the technical hydrogeological and water budget information used by the GSAs to implement the* GSPs and management area plans *and to provide the common, basin-wide information in accordance with coordination agreement,* ~~*adopted by the GSAs and*~~ *must be* prepared by professional geologists and engineers in accordance with the SGMA regulations ~~*include SGMA Projects that could increase produced water reuse in the KCS*~~. The *adopted GSPs and management area plans include several proposed measures that could increase water supplies or potentially reduce demand, but the* feasibility of these SGMA Projects is ~~*being*~~ *subject to adaptive management, including* evaluat*ion and revision in response to monitoring and at regular intervals over the 20-year period for compliance created by the Act.* ~~, ed in the context of the SGMA in the Project Area.~~ *The SGMA is a novel, locally based approach to long-term groundwater sustainable management and requires that undesirable results be avoided by implementing comprehensive solutions for each applicable basin and subbasin. The formation of GSAs; the adoption of GSPs and management area plans; the development of technical hydrological information at a basin, subbasin, and plan level; and the consideration and integration of a wide range of interests affected by groundwater as defined in the SGMA legislation has never before been attempted in California. The adopted GSPs in the Project Area represent initial approaches for implementing the SGMA that will be adaptively managed and revised as necessary to comprehensively meet SGMA requirements over the statutory 20-year compliance period and a 50-year planning and implementation horizon.* ~~*The County has substantially less capacity to identify and implement mitigation measures that would predictably increase the reuse of produced water than the GSAs and the management entities implementing the GSPs, Management Area plans, and SGMA Projects involving produced water reuse in the Project Area. It is possible that any such measures, moreover, could conflict with and adversely affect the development of produced water SGMA Projects as the GSPs and Management Area plans are implemented. Due to these considerations, there are no feasible mitigation measures that would result in predictable levels of produced water reuse and reduce the Project's significant impacts to water supplies.*~~

The following sections discuss the feasibility of potential mitigation measures for water supply impacts.

The County could potentially implement a mitigation measure that requires the additional reuse of produced water for agricultural irrigation to offset the Project impacts to M&I water supplies. As discussed in Section 4.9.2, Hydrology and Water Quality, Environmental Setting, Project Area Groundwater Sustainability Plans and Oil and Gas Activities, and in Appendix D, several GSPs and management area plans include potential SGMA Projects that would, if successfully implemented, increase produced water imports for beneficial use SGMA planning areas. None of the plans, however, indicate that any such increased reuse will be feasible; several, including the Cawelo GSP, explicitly state that the amount of produced water available for reuse in the future cannot be predicted due to potential regulatory and technical feasibility constraints. At present, the potential expansion of produced water reuse included in GSPs and management area plans is subject to ongoing feasibility studies to determine whether increased produced water supply imports can be achieved.

As discussed above and in Appendix D of this SREIR, in late 2019 and early 2020, state regulators indicated that they wish to curtail oil and gas activities in California. In recent years, the oil and gas industry has experienced lower prices, including a brief period in 2020 when spot market futures for oil turned sharply negative for the first time in history. The County cannot mandate that oil and gas operators generate produced water in predictable amounts over time, and has no authority or control to regulate state policies or national and international conditions affecting industry operations, including produced water generation. As discussed in Section 4.9, Hydrology and Water Quality, 4.9.3, , Regulatory Setting, subsection Produced Water Reuse for Agricultural Irrigation, although there is no evidence to date that permitted produced water reuse for irrigation in the Project Area has caused health or safety issues, there is continued opposition to and concern about such reuse. Since 2015, the CVRWQCB has created the ongoing Food Safety Project, including an expert panel, to continue to evaluate and assess these concerns. It is possible that, even if additional amounts of produced water imports for irrigation are technically feasible to generate and available in the future, health and safety concerns would preclude such use. Given these considerations, the implementation of a mitigation measure to offset oil and gas M&I water use with predictable amounts of produced water reuse is infeasible.

The County could implement a mitigation measure to reduce potential Project groundwater impacts by limiting the amount of oil and gas activity in the Project Area through a permit quota or similar measure. Alternatively, the County could ban the use of higher quality water supplies for certain oil gas operational activities, such as steam production for EOR, well completion, and other operations. These measures are infeasible for several reasons.

First, as discussed in Chapter 6.0, Alternatives, any such measures would expose the County to substantially significant liability for regulatory taking claims, including significant litigation costs and related budgetary and management uncertainty involved in resolving any such claims. Second, the limitation of oil and gas activity is inconsistent with one of the Project's primary purposes, which is to encourage and expand one of the County's largest and most essential industries with a *ministerial permitting program, subject to specific permitting criteria and new and expanded environmental protections.*

~~*The County could potentially implement a mitigation measure that would ban the use of domestic or irrigation-quality water by oil and gas producers. Any such mitigation measure would be infeasible for several reasons.*~~ *Although Mitigation Measures (MM) 4.17-2 to 4.17-4 struck down by the Appellate Court sought to increase the use of additional produced water and reclaimed water in place of M&I quality water, there is no substantial evidence that treatment technologies and distribution systems in the Project Area can be feasibly developed and operated in a manner that would reduce M&I water use by oil and gas operators in a predictable manner over time and without causing other significant environmental impacts. During 2016 to 2019, when MM 4.17-2 to 4.17-4 in the 2015 FEIR were in effect, certain of the Applicants were able to implement measures to reduce oil and gas use of higher quality M&I water, and additional measures were planned for future periods (WSPA 2020). While this information shows that it may be possible to encourage reduced M&I water use, it does not demonstrate that any such reduction can be feasibly implemented in a manner that will reduce Project water supply impacts to a predictable extent and on a widespread basis throughout the Project Area.*

Certain oil and gas operations, such as well drilling and abandonment work, require high quality water to properly formulate the cement mixtures that are needed to safely drill and abandon wells. Steam generation required for oil and gas production can also require higher-quality water supplies than are typically obtained from treated produced water to avoid equipment corrosion or damage and potential chemical interactions. Use of produced water in certain oil and gas operations can also lead to increased need for equipment maintenance due to, for example, silica buildup or tube failures in boilers. Using untreated or lower quality produced water for these activities would jeopardize the operators' ability to comply with regulatory requirements applicable to well construction and abandonment and the safe operation of oil field equipment, including the avoidance of corrosion.

The use of produced water for well stimulation treatments would also significantly increase chemical use as well as costs. Chemicals used in fracture treatments impart viscosity for proppant transport and fracture geometry creation and improve post-treatment production results by minimizing polymer plugging and other phenomena detrimental to production. Using produced water instead of fresh water as a base fluid for fracture treatments would increase the chemical volumes needed to fulfill these functions. Produced water use for fracture treatments could require as much as a five-fold increase in buffering agents, and additional chelating agents, clay and scale inhibitors, and surfactants to prevent emulsions and reduce surface tension may also be needed to minimize production complications that would be caused by the use of produced water. While produced water could be pre-treated to require fewer chemicals during the fracture treatment itself, such pre-treatment conditioning would also involve more chemicals, equipment, or both, to obtain water sufficient for use in the fracture treatment. Because of these complications, a typical fracturing operation would become significantly more expensive, and often uneconomical. In addition, for some types of well stimulation, such as matrix acid stimulation, it is technologically infeasible to utilize produced water. Typically, matrix acid stimulation employs hydrofluoric acid, which can only be mixed with fresh water. If hydrofluoric acid comes into contact with formation brine, insoluble precipitants form, limiting the effectiveness of the acid stimulation system by plugging pore throats in the reservoir pore network. Such plugging can completely counteract the effects of the stimulation treatment. The reduction in the effectiveness of the treatment would require more frequent treatments, larger treatments, or both, which would lead to a significant increase in use of chemicals, emissions, and heavy vehicle traffic hauling hazardous chemicals.

Produced water is currently used for some oilfield activities, such as discharge for dust suppression, but increasing that use beyond existing levels would require additional permitting and approvals to avoid impacts to biological, water, and other resources. Additionally, the lack of infrastructure linking sources of produced water to the locations where water may be used, particularly in cases of new exploration, can result in increased truck trips and other more significant impacts associated with transporting produced water to operation sites. For example, pilot EOR projects typically cannot use recycled water due to the early stage of project development, which results in a lack of available recycled water *that can be obtained from recycled water suppliers using existing, or feasibly expanded, treatment and distribution facilities*. Furthermore, the treatment of water for reuse requires specialized equipment, consumes energy, and generates waste. In many cases, operators have also contracted with local water purveyors to utilize some supply of purchased water over a long-term contract; cancellation of such contracts would also create negative financial impacts for the region.

As discussed in Section 4.9, Hydrology and Water Quality, most of the use of M&I supplies for EOR occur in the Western Subarea because existing water quality is particularly poor in that portion of the Project Area. A feasible method for treating and distributing treated local low quality water or produced water for widespread EOR use has not been identified in that region. As summarized in Section 4.9.2, Hydrology and Water Quality, Environmental Setting, Project Area Groundwater Sustainability Plans and Oil and Gas Activities, certain of the GSP and management area plans, including the Westside District Water Authority (WDWA), have proposed SGMA Projects that could treat local groundwater or produced water with several potential technologies to enhance local supplies. However, the WDWA GSP specifically states that the feasibility of any such treatment and reuse is under investigation. Unresolved issues cited in the plan and that are subject to a feasibility study include "regulatory acceptance, potential for undesirable results (e.g., significant subsidence), and for the economics of treating both brackish groundwater and oil field produced waters in a distributed modular facility via the use of readily available membrane technologies, such as reverse osmosis (RO). Treatment technologies to be assessed would include pre-treatment, pH adjustment and filtration followed by either a single-pass RO configuration, a double-pass RO, or a RO modification called a closed-circuit RO." (Aquilogic 2019)

The plan further states that the feasibility study includes "Evaluating existing hydrogeologic data pertaining to brackish groundwater and oil field produced water quality, water use, and volumes; Development of preliminary engineering options and costs for siting the treatment facility, source wells, water treatment, energy demand, concentrate disposal, and treated water transmission; Examination of the potential for undesirable results (e.g. subsidence); and Assessment of permitting and public notification requirements (California Environmental Quality Act [CEQA], etc.)" Aquilogic 2019). In addition, the plan states that a "project alternative analysis will be *performed leading to a recommended plan for implementation including a preliminary construction schedule and financing plan, a revenue program, and a net present worth analysis." The WDWA management plan has a "goal to have the first modular treatment system online before the end of the second five-year [GSP] reassessment period (by 2030)" (Aquilogic 2019). There is no substantial evidence that the ongoing feasibility study will result in any amount of local water or produced water treatment sufficient to supply any or a predictable amount of oil and gas industry M&I water requirements, including EOR, in the Project Area. Similarly, none of the other GSPs or management area plans provide any evidence that additional amounts of produced water can be feasibly and reliably imported for use in SGMA-regulated basins and subbasins in the Project Area.*

In response to a domestic and irrigation-quality water use ban, oil and gas operators in the Project Area would likely be required to treat additional amounts of produced water to domestic or irrigation-quality for activities that require higher quality water supplies. ~~*As discussed in the GSPs and Management Area plans, including the Cawelo GSA Management Area Plan and the Westside District Water Authority Management Area Plan, this treatment would require technologies, such as reverse osmosis, with significant capital and operational costs.*~~ Many Project Area oil and gas operators lack the technological expertise and economic capacity to treat produced water. A domestic and irrigation-quality water use ban could reduce or preclude oil and gas activities and generate adverse economic and social consequences in the County. The curtailment of oil and gas operations that generate produced water could also conflict with the implementation of SGMA Projects in the adopted GSPs and Management Area plans for the KCS that would use produced water supplies. *The potential reduction in the availability of produced water for irrigation reuse is specifically cited in the Cawelo GSA management area plan as a factor that precludes the plan's ability to project that historical or anticipated produced water imports will in fact be available in future years.* The County does not have ~~*produced*~~ water treatment and distribution facilities sufficient to produced and deliver higher quality water to oil and gas operators throughout the Project Area. As a result, higher quality water would need to be generated in new, energy intensive facilities and delivered by truck to most of the Project Area, which would require additional permitting processes to avoid adverse secondary environmental impacts, including increased energy and vehicular use and greenhouse gas emissions.

Due to the risks of chemical interactions adversely affecting health, safety, and equipment integrity that would result from using produced water for certain operations, the additional delivery infrastructure, truck trips, and brine disposal required to generate higher quality supplies from produced water, technological and economic challenges, and the likelihood of adverse social and economic impacts in the County, the complete elimination of domestic and irrigation-quality water by oil and gas operators in the Project Area is economically, socially, environmentally, and technologically infeasible.

As summarized in Section 4.9.2, Hydrology and Water Quality, Environmental Setting, Project Area Groundwater Sustainability Plans and Oil and Gas Activities, the adopted GSPs and management area plans in the Project Area identify several SGMA Projects that could increase water supplies, reduce demand, or otherwise facilitate the achievement of SGMA objectives within the 20-year statutory time frame for compliance. The County could implement a mitigation measure that would require oil and gas operators permitted under the proposed Project to pay a fee that would be used to ~~*develop produced water treatment facilities and enhanced reuse in the Project Area*~~ *implement one or more of these SGMA Projects to reduce or avoid Project groundwater impacts. This mitigation approach is infeasible for several reasons.* ~~*The imposition of a fee is infeasible for several reasons. The County lacks the expertise and technical capacity to implement and manage a produced water treatment and distribution system in the Project Area. Consequently, fees collected from oil and gas applicants would need to be provided to other entities that have a demonstrable capacity to operate and manage produced water treatment and distribution facilities with sufficient capacity and scope to serve the Project Area.*~~

As discussed ~~*above,*~~ *in Section 4.9.2, Hydrology and Water Quality, Environmental Setting, SGMA Overview, the GSPs and management area plans adopted in the Project Area represent the first step towards implementing a novel, complex, and historically unprecedented locally based sustainable groundwater management program. The plans focus on adaptive management to respond to the multiple interests affected by the comprehensive groundwater management required by the SGMA, and to adjust initially proposed SGMA Projects during successive plan refinements as needed over the statutorily created 20-year SGMA compliance period. The need for adaptive management and implementation flexibility in the SGMA process, and the need for planning adjustments over time, has been noted in publications by both SGMA practitioners and academic researchers (Montgomery & Associates 2020; Escriva-Boua 2020). There is no assurance that any specific SGMA Project, including expanded produced water treatment and reuse discussed above, will result in water supply increases or demand reductions that would predictably reduce or avoid Project groundwater impacts. Academic studies have indicated that, based on statistical models, increased groundwater pumping restrictions increase the likelihood of successfully reducing overdrafts in California. (Escriva-Boua 2020) The County has no authority to directly regulate or control groundwater pumping, and the SGMA provides such authority only to duly formed GSAs that adopt a GSP in accordance with the Act.*

The County could indirectly attempt to reduce water demand in the Project Area by purchasing and fallowing agricultural land, a potential SGMA Project discussed in several GSPs and management area plans. Demand reduction through such measures conflicts with the County's General Plan objectives of preserving and enhancing agriculture. The implementation of fallowing and similar demand reduction for Project mitigation purposes would also conflict with the express objectives of adopted GSPs in the Project Area, such as the Kern River GSP, which specifically states that "demand reduction projects could have a detrimental impact on the local economy, livelihood of residents and business owners, and the well-being of Metropolitan Bakersfield and Kern County. Therefore, large-scale reductions are not proposed in Phase One and may be unnecessary for achieving the sustainability goal. At a minimum, such actions are delayed until later in the implementation period to allow water supply projects the opportunity to sustainably support current and projected growth in the beneficial uses of groundwater." (KRGSA 2020)

Similarly, agricultural fallowing would conflict with the KGA GSP's express concerns that SGMA plans be adaptively managed because "The communities, the economy, and local governments are and have been reliant on Kern County agriculture and are dedicated to preserving the viability *of agriculture into the future" (KGA 2019). Finally, it is not clear that fallowing and similar demand reduction measures by curtailing Project Area water use by itself would reduce water demand without additional restrictions. Growers that have not ceased operations, for example, may be induced to increase irrigation or plant more remunerative crops with higher water demands in response to the fallowing of adjacent formerly operating farmland. As discussed in Section 4.9, Hydrology and Water Quality, Impact 4.9-2, fallowing programs in the Project area are already being funded and implemented by other agencies and do not predictably result in reduced net water use. Other SGMA Projects, such as expanded produced water reuse are discussed above and are subject to similar uncertainty concerning feasibility and predictable water supply mitigation effects.*

The SGMA requires, and was designed by the legislature to achieve, a comprehensive sustainable groundwater management solution for high priority basins and subbasins implemented over a 20-year period by legislatively authorized, newly created local agencies (GSAs) implementing, where applicable, coordinated GSPs and management area plans. The precise supply enhancement, demand reduction, and other SGMA Projects that will be required to achieve SGMA requirements in the Project Area are yet to be determined and will require the balancing of multiple interests, the use of still-developing technical information, and adaptive management in response to long-term monitoring to be achieved. As stated in the Kern River GSP, this process is being explicitly managed to avoid detrimental impacts to the local economy, livelihood of residents and business owners, and the well-being of Metropolitan Bakersfield and Kern County, to the extent possible. It is virtually certain that the SGMA process, including the identification and implementation of SGMA Projects, will be significantly modified during successive GSP and management plan five-year reviews, during the 20-year compliance period, and over the 50-year planning and implementation horizon mandated by the SGMA and the SGMA regulations.

Based on these considerations, the County will implement two water supply mitigation measures to ensure that Project-related groundwater use is integrated with the comprehensive SGMA compliance process in the Project Area.

MM 4.17-3 requires that all Oil and Gas Conformity Reviews and Minor Activity Reviews disclose whether any groundwater or reclaimed water will be used for the proposed oil and gas activity. Groundwater may only be used from wells equipped with a water meter. All applicants will be required to provide the specific details on water use when the permit is submitted that includes: (1) the source and estimated amount of any groundwater being used in the permitted activity; (2) confirmation that any water well that provides any groundwater used for a permitted activity is metered; and (3) the source and estimated amount of any reclaimed water used in the permitted activity. This information will be compiled into a report by Kern County Planning and Natural Resources and posted on the department website by December 31 of each year. It will also be sent directly to all the GSAs and the Kern County Water Agency for informational purposes.

MM 4.17-4 requires the County to provide public notice of any Conditional Use Permit (CUP) to all GSAs in the valley for review and comment.

~~*while several of the GSPs and Management Area plans contemplate SGMA Projects that would expand produced water reuse, no new produced water treatment or distribution facilities have been constructed, none are operating, and none have generated specific and predictable volumes of additional produced water reuse. Most of the SGMA Projects involving produced water are subject to ongoing or proposed feasibility studies that have not been completed. As discussed above, and also in the Westside District Water Authority Management Area Plan, produced water treatment and distribution could have several significant environmental impacts such as greenhouse gas emissions and concentrated brine disposal that will need to be fully evaluated.*~~

~~*In the absence of an established produced water treatment and distribution program in the Project Area, there is no substantial basis for determining that the collection of water fees from oil and gas applicants will result in a predictable reduction of oil and gas domestic and irrigation-quality water use. The imposition of a fee, however, would increase costs for oil and gas producers, particularly smaller operators, and could result in operational curtailment in the Project Area. The curtailment of oil and gas operations that generate produced water could conflict with the implementation of SGMA Projects in the adopted GSPs and Management Area plans for the KCS that would use produced water supplies. A reduction in oil and gas activities would also generate adverse economic and social consequences in the County. The payment of a fee to enhance produced water reuse in the Project Area is economically, socially, environmentally, and technologically infeasible.*~~

MM 4.17-3 will ensure that all Project activities subject to Oil and Gas Conformity Reviews and Minor Activity Reviews l fully account for any groundwater and reclaimed water use, and that any groundwater will only be obtained from metered wells. An annual report prepared by the Kern County Planning and Natural Resources Department will report the amount of groundwater and reclaimed water used in the prior year, and that all groundwater source wells are metered. MM 4.17-4 will ensure that applicable water management agencies have the opportunity to review and comment on the availability and usage of water prior to permitting of any oil and gas activity subject to CUP approval by the County. This information will be available for integration and use by Project Area GSAs in the adaptive management of adopted GSPs and management area plans to achieve the comprehensive sustainable groundwater management solution required by the SGMA.

MM 4.17-3 and 4.17-4 will support the implementation of the SGMA in the Project Area. ~~*Based on these considerations*~~, *As discussed above,* there are no *other* feasible mitigation measures that would reduce Project's significant *water supply* ~~sustainable groundwater management~~ impacts to a reasonably predictable extent. It is possible that, consistent with the adopted GSPs and management area plans in the Project Area, additional produced water will be used to supplement supplies in the KCS and in other locations over time. While this outcome would support rather than impact sustainable groundwater management and SGMA plan implementation in the Project Area, SGMA Projects that would increase produced water reuse have yet to be implemented by the GSAs with statutory authority for managing groundwater in the Project Area. Accordingly, oil and gas demand for domestic and irrigation quality water is projected to increase from 8,778 AFY to 11,761 AFY with the implementation of the Project. Due to the lack of surplus water supplies in the Project Area, this level of consumption, although relatively small in comparison with other uses, is a significant impact and contributes to a cumulatively significant impact to ~~*sustainable groundwater management*~~ *water supplies*.

MM 4.17- 3 address accountability for water use, require metered wells and coordinate information with water districts and the GSAs responsible for groundwater management in the oilfield production areas. However, even with these mitigation measures, these impacts would be significant and unavoidable.

As discussed in the analysis, the following mitigation measures— 2015 FEIR MM 4.17-2 through 4.17-4—were included in the 2015 FEIR but have been determined to be economically, socially, environmentally, and technologically infeasible and are not being recommended for adoption.

~~**MM 4.17-2 (2015 FEIR)** Applicant shall increase the re-use of produced water, and reduce its use of municipal and industrial-quality ground or surface water use to the extent feasible. By the end of 2016, the Applicants shall work with the County to review water use data submitted to Division of Oil Gas and Geothermal Resources under Senate Bill 1281 and identify the five biggest oil industry users of municipal and industrial water by volume. The five biggest oil industry users of municipal and industrial water shall work together to develop and implement a plan identifying new measures to reduce municipal and industrial water use by 2020. The plan shall address the following activities, as appropriate: steam generation; drilling and completions (including hydraulic fracturing); dust control; compaction activities related to construction; and landscaping. Through the KernFLOWS initiative or other efforts (e.g., Groundwater Sustainability Agency), the five biggest oil industry users of municipal-and-industrial water shall also work with local agricultural producers and water districts to identify new opportunities to increase the use of produced water for agricultural irrigation and other activities, as appropriate. Any produced water treated and used for agricultural irrigation or other activities shall be tested and monitored to assure compliance with applicable standards for such agricultural irrigation or other uses.~~

~~**MM 4.17-3 (2015 FEIR)** In the County's required participation for the formulation of a Groundwater Sustainability Agency, the Applicant shall work with the County to integrate into the Groundwater Sustainability Plan for the Tulare Lake-Kern Basin, best practices from the oil and gas industry to encourage the re-use of produced water from oil and gas activities, and (with appropriate treatment) to produce new water supplies for other uses such as agricultural irrigation and groundwater recharge. The produced water re-use goal is 30,000 acre-feet per year, which would offset more than the current use of imported water and groundwater from non-oil bearing zones by the oil and gas industry~~.

~~**MM 4.17-4 (2105 FEIR)** The Applicant shall work with the County on the Groundwater Sustainability Plan to increase Applicant use of reclaimed water and reduce the Applicant's use of municipal-and-industrial quality imported surface water or~~

~~groundwater. The Applicant will provide copies of water use reports produced under AB 1281 to the Groundwater Management Agency, which will then integrate this information into the Groundwater Sustainability Plan required under the Sustainable Groundwater Management Act.~~

MITIGATION MEASURES

MM 4.17 -3 All Oil and Gas Conformity Reviews and Minor Activity Reviews shall provide information on any groundwater or reclaimed water will be used. Unmetered water wells cannot be used as a source of groundwater for the permit activity. Groundwater may only be used in a permitted activity from a water well equipped with a water meter. The Planning and Natural Resources Department shall compile the water use information in a report that shall be posted on the Kern County Planning and Natural Resources website for public use by December 31 of each calendar year. A copy shall be sent to all Groundwater Sustainability Agencies and the Kern County Water Agency after being posted on the website. The information submitted on the permit shall include the following data:

A. The source and estimated amount of any groundwater being used in the permit activity.

B. Confirmation that any water well used in permit activity is metered

C. The source and estimated amount of any reclaimed water used in the permit activity.

MM 4.17- 4 Public Notices for all Conditional Use Permits for oil and gas activities shall be sent to the appropriate Water Districts, Groundwater Authorities, and the Kern County Water Agency for review and comment on water availability and usage.

~~*No feasible or reasonable mitigation measures are available.*~~

Level of Significance After Mitigation

Significant and unavoidable.

Impact 4.17-5: Result in a determination by the waste water treatment provider which serves or may serve the project that it has adequate capacity to serve the project's projected demand in addition to the provider's existing commitments

Chapter 17, Utilities and Service Systems, of the 2015 FEIR, Chapter 4.9, Hydrology and Water Quality (SREIR Volume 3) discussed the relation of the project to wastewater treatment and disposal and treatment facilities. As discussed in Section, 4.12 Population and Housing (SREIR Volume 3), no population or employment growth is anticipated as part of the Project and is fully discussed that chapter. Project-related sanitary wastewater generation would not exceed the capacity of wastewater treatment providers and impacts would be less than significant.

MM 4.17-1 from the 2015 FEIR continues to be required.

Mitigation Measures

Implement MM 4.17-1, as described above.

Level of Significance After Mitigation

Impacts would be less than significant with mitigation.

Impact 4.17-6: Generate solid waste in excess of state or local standards, or in excess of the capacity of local infrastructure, or otherwise impair the attainment of solid waste reduction goals

The analysis of the Project's potential to generate solid waste in excess of state or local standards, or in excess of the capacity of local infrastructure, or otherwise impair the attainment of solid waste reduction goals, was assessed in Section 4.17, Utilities and Service Systems, of the 2015 FEIR (SREIR Volume 3). MM 4.17-2 in the 2015 FEIR continues to be required. The Project would generate solid waste during construction and operations. Drilling and production wastes are non-hazardous. Most drilling and production wastes would be managed using one of the following methods (all of which require compliance with applicable laws and regulations):

- Underground injection, such as in disposal wells;
- Onsite burial, such as in pits, and landfills of non-hazardous drilling muds;
- Land treatment, such as by land spreading, land farming, and road spreading of non-hazardous oily dirt;
- Evaporation; and
- Discharge to evaporation and percolation ponds.

Other types of waste generated in oilfield operations include wood, metal equipment parts, damaged tools, construction debris, excess soil and vegetation generated from cutting and grading, concrete residue, pallets, cardboard boxes, papers, plastics, banding materials, scrap steel, scrap aluminum, scrap wire, and general trash. These wastes are collected at specially permitted in-field solid waste transfer stations or disposed of in onsite permitted facilities, or transported to offsite landfills or recycling facilities, as appropriate, on a regular basis. Transfer stations consist of containers where waste is collected for transfer to Kern County landfills or other approved sites. It is estimated that 11 cubic feet of road mix would be generated per well. Excess soil and vegetation (mulched) found to be nonhazardous could be used as ground cover.

The California Solid Waste Reuse and Recycling Access Act of 1991, as amended, requires expanded or new development projects to incorporate storage areas for recycling bins into the project design. Reuse and recycling of construction debris would reduce operating expenses and save valuable landfill space.

Several landfills within the County have available capacity to accommodate the solid waste anticipated to be generated by the Project through and beyond 2035, and, as discussed above much of the solid waste that would be generated by oil and gas activities would be managed onsite. Therefore, the Project would not be expected to significantly impact Kern County landfills. Nevertheless, MM 4.17-2 is required to ensure compliance with policies to reduce waste sent to landfills.

Mitigation Measures

MM 4.17- 2 During construction activities for Project facilities, the Applicant shall not store construction waste onsite for longer than the duration of the construction activity, or transport any waste to any unpermitted facilities. The Applicant shall also reduce construction waste transported to landfills by recycling solid waste construction materials, such as taking materials to recycling and reuse locations listed in the brochure on recycling construction and demolition materials available on the Kern County Public Works Department, website.

Level of Significance After Mitigation

Impacts would be less than significant with mitigation.

Impact 4.17-7: Comply with federal, State, and local management and reduction statutes and regulations related to solid waste

The analysis of the Project's potential to comply with federal, State, and local management and reduction statutes and regulations related to solid waste was assessed in Chapter 4.17, Utilities and Service Systems, of the 2015 FEIR (SREIR Volume 3). MM 4.17-2 from the 2015 FEIR continues to be required. As discussed above, the Project would generate solid waste during construction and operations. The 1989 California Integrated Waste Management Act (AB 939) requires Kern County to attain specific waste diversion goals. In addition, the California Solid Waste Reuse and Recycling Access Act of 1991, as amended, requires expanded or new development projects to incorporate storage areas for recycling bins into the project design. AB 341 requires additional solid waste recycling by 2020. Implementation of MM 4.17-2 will ensure compliance with policies to reduce waste sent to landfills.

Mitigation Measures

Implement MM 4.17-2, as described above.

Level of Significance After Mitigation

Impacts would be less than significant with mitigation.

4.17.5 Cumulative Setting, Impacts, and Mitigation Measures

The geographic scope for cumulative impacts to utilities and service systems includes the area within 6 miles of the external Project Area. While projects in a larger area may affect some of the same resources as the Project, by focusing on projects within the Project Area and 6 miles outside of the Project Area, the analysis of cumulative impacts includes the projects that would most comparably affect the same resources as the Project.

Impact 4.17-8: Cumulative Impacts on Utilities and Service Systems

Kern County has grown, and is expected to continue to grow, with or without the Project, consistent with the growth projections included in the Kern COG Regional Transportation Plan/Sustainable Communities Strategy and accompanying Environmental Impact Report.

As described above, the ongoing production of oil and gas in Kern County, with the additional mitigation measures and other substantive and procedural requirements included in the Project's proposed revisions to the County's oil and gas ordinances, would not be expected to result in any substantial increase in population.

Significant cumulative impacts to public services would occur if the cumulative projects would overburden the public service agencies and if utility providers were unable to provide adequate services. The cumulative projects would substantially increase the demand for public service providers and utility servers. As discussed above, the Project would not increase the demand for municipal wastewater treatment, stormwater management, or landfills. Incorporation of MM 4.17-1 and MM 4.17-2, described above, would further reduce impacts from the proposed Project, in conjunction with other projects in the area, to a less than significant cumulative level for public utilities use except water supply.

The Project would result in the increased oil and gas use of domestic and irrigation-quality water from 8,778 AFY in 2012 to 11,761 AFY in 2035. As discussed in Impact 4.17-4, due to the lack of surplus water supplies in the Project Area, this level of consumption, although relatively small in comparison with other uses, is a significant impact and contributes to a cumulatively significant impact to regional water supplies. It is possible that, consistent with the adopted GSPs and Management Area plans in the Project Area, additional produced water will be used to supplement supplies in the KCS and in other locations over time. While this outcome would support rather than impact water supplies in the Project Area, SGMA Projects that would increase produced water reuse have yet to be implemented by the GSAs with statutory authority for *implementing the SGMA* ~~*managing groundwater*~~ in the Project Area. Accordingly, oil and gas demand for domestic and irrigation-quality water is projected to increase from 8,778 AFY to 11,761 AFY with the implementation of the Project, a level of water use that will contribute to a cumulatively significant impact to water supply. ~~*As discussed under Impact 4.17-4, there are no feasible mitigation measures that will reduce the Project's projected impacts to a predictable extent. As a result, cumulative impacts to water supply will remain significant and unavoidable.*~~

Oil and gas demand for M&I water is also projected to increase by about 2,982 AFY from 2012 levels by 2035. As discussed above and in 2015 FEIR Appendix T, surplus M&I-quality water is not available in the Project Area. Any new use reduces the availability of M&I-quality water to another Project Area user, or increases the regional groundwater overdraft if supply shortfalls are addressed by increased groundwater extraction. Consequently, existing entitlements and resources are insufficient to meet the current and projected future M&I water demand in the Project Area, and increasing M&I water demand under overdraft conditions would contribute to a significant cumulative water supply impact in the Project Area.

As discussed under Impact 4.17-4, it is not feasible to implement mitigation measures that directly curtail oil and gas activities to reduce water demand, or indirectly attempt to reduce or avoid Project impacts by curtailing demand from other activities, including agriculture. Although the GSPs and management area plans in the Project Area identify SGMA Projects that could be implemented to achieve SGMA goals over the next 20 years, it is virtually certain that these will be modified through the adaptive management of the plans, in response to the multiple interests that Project Area GSAs are required to consider under the SGMA, as additional technical and monitoring information is developed, and as the GSAs with the statutory authority to implement the SGMA attempt to minimize detrimental impacts to the local economy, livelihood of residents and business owners, and the well-being of Metropolitan Bakersfield and Kern County.

Water Code Section 10723.2 requires that duly formed GSAs consider the interests of all beneficial uses and users of groundwater in the development and implementation of GSPs and management area plans, including disadvantaged communities. There is substantial evidence that, due in part to a lack of resources, disadvantaged community interests in groundwater supplies have not been sufficiently considered in the development and implementation of GSPs and management area plans. A July 2020 report by researchers at the University of California, Davis found that most GSPs developed in the state do not adequately consider how drinking water stakeholders could be impacted based on applicable SGMA Sustainable Management Criteria and do not promote disadvantaged community benefits (Dobbin et al. 2020). Project M&I water use contributes towards a cumulatively significant impact on disadvantaged communities that are beneficial users of groundwater but not adequately considered in SGMA plans adopted in the Project Area.

MM 4.17-5 requires that oil and gas applicants subject to Oil and Gas Conformity Review pay a $250 mitigation fee per well and those subject to Minor Activity Reviews pay $50 per well . These funds will be deposited into a Disadvantaged Community Drinking Water Grant Fund to be implemented by Kern County Public Health in the form of grants available only for projects in disadvantaged communities in the Valley portion of Kern County. The use of the grant funding would be targeted for the design, permitting, and construction of physical improvements to water wells or water systems serving the disadvantaged community and primarily would act as matching funds for larger grant opportunities from other sources. Based on the average permitting activity, this mitigation will generate an estimated $460,000 annually. These funds will mitigate the Project's fair share of cumulative impacts to disadvantaged communities that are insufficiently considered in the existing SGMA process.

As discussed under Impact 4.17-4, there is no other feasible mitigation for reducing the Project's potential water supply impacts. MM 4.17-3 and 4.17-4 will ensure that future activities permitted under the Project, including activities subject to Oil and Gas Conformity Reviews and Minor Activity Reviews, and permitted through the County's CUP process, will provide regional groundwater management agencies with sufficient information, including groundwater use from *metered wells, to integrate Project-related groundwater use with the development of a comprehensive sustainable groundwater management solution for basins and subbasin in the Project Area.*

Accordingly, oil and gas demand for domestic and irrigation quality water is projected to increase from 8,778 AFY to 11,761 AFY with the implementation of the Project, a level of water use that will contribute to a cumulatively significant impact to water supplies. ~~*The allocation of water supplies and water demands, the complex laws affecting water rights, the many water districts that have legal jurisdiction over one or more sources of water in the Project Area, the varied technical feasibility of treating produced water, and the produced water reuse opportunities, all present complex variables that fall outside the scope of the County's jurisdiction or control under CEQA. The County concludes that other agencies can and should cooperate in water management planning and implementation actions under the SGMA and other applicable laws to improve the quantity and reliability of water supplies in the Project Area. Because of significant ongoing regional uncertainties regarding water supplies, and the need for agencies other than Kern County to take action to improve management of regional water supplies to meet existing and reasonable foreseeable demand, cumulative impacts to water supplies would*~~ *This impact will* remain significant and unavoidable.

Mitigation Measures

Implement MM 4.17-1 through MM 4.17 -5

MM 4.17–5 The Applicant shall pay a mitigation fee on each well of $250 for an Oil and Gas Conformity Review and$ 50 for each well in a Minor Activity Review. These funds shall be deposited into a Disadvantaged Community Drinking Water Grant Fund to be implemented by Kern County Public Health, which shall administer the selection and awarding of grants. Grants shall be available only for projects in disadvantaged communities in the Valley portion of Kern County, and may only be used for the design, permitting, and construction of physical improvements to water wells or water systems serving the identified Disadvantaged Community. The Disadvantaged Community may be within an incorporated city limits.

Level of Significance After Mitigation

Significant and unavoidable with respect to water supply. Less than significant with respect to other public utilities, including municipal wastewater treatment, stormwater management, or landfills with mitigation.

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Section 4.18
Supplemental Analysis

Section 4.18
Supplemental Analysis

4.18.1 Clarification of Analysis and Mitigation Measures

The Kern County Planning and Natural Resources Department has implemented the permit program established by the Project for over four years as of March 26, 2020, and this permit system is described in Section 1.3, Project History. As described in Section 3, Project Description, the Project includes minor administrative changes to the 2015 Kern County Zoning Ordinance (Ordinance), and clarifications for some of the mitigation measures, to further improve the ministerial permit process. These clarifications are informed by both the County's implementation experience to ensure applicant compliance and by the adopted process and online permit system, as well as materials prepared by the County to provide guidance and direction to the applicants on submitting applications and implementing mitigation measures.

As described in Section 3.1.1, Revisions to Title 19 - Kern County Zoning Ordinance (2020) and Related Changes, the only proposed changes to the 2015 Ordinance are additional application processing details for online management of permits, clarification of the process for monitoring Split Estate 120-day process, updates of names of County departments and State agencies that have changed since 2015, references to this Supplemental Recirculated Environmental Impact Report (SREIR), and adjustment of Tier Maps for geographic information system (GIS) technical errors identified from the 2015 adoption. These Ordinance revisions do not authorize new or different industry activities and will not result in any changes to the physical environment warranting further California Environmental Quality Act review.

The Ordinance also requires implementation of the mitigation measures from the 2015 FEIR. Some of these mitigation measures have been modified based on analysis performed for this SREIR, as described in Chapter 4, Supplemental Analysis, and in Sections 4.2, Agriculture and Forest Service, 4.3, Air Quality, 4.9, Hydrology and Water Quality, 4.12, Noise, and 4.17, Utilities and Service Systems. In addition, a comprehensive review has been completed of all mitigation measures from the 2015 Final Environmental Impact Report (FEIR) to identify clarifications that should be made in identified mitigation measures for minor word modifications. For each of the identified environmental topical areas discussed in this section, clarifying word modifications are shown in strikethrough of deleted text and underlining for replacement wording for reading purposes. The recommended mitigation measures are shown in final form. As the name of County departments and State agencies have changed since 2015, these changes will be automatically made for mitigation measures that have no other changes. The complete analysis of the impacts and the mitigation measures are contained in the 2015 FEIR sections for each resource area, which is provided in Volume 3 of this SREIR. *Except where specifically noted, all underlined and italicized text are additions, and italicized strikethrough text are deletions from the SREIR (August 2020). Non italicized underlined and strikethrough text is the same as in the SREIR (August 2020).*

4.18.1.1 Aesthetics and Visual Resources

The 2015 FEIR (Section 4.1, Aesthetics and Visual Resources) included Mitigation Measures (MMs) 4.1-1 to 4.1-6 to mitigate aesthetic impacts, and concluded that aesthetics would remain significant and unavoidable because oil and gas activities would continue to produce visible changes to the existing environment, and the potential to produce a new source of substantial light and glare that would adversely affect day or nighttime views in the area.

Clarified MM 4.1 -1

MM 4.1-1 requires word modifications to give clear direction to applicants on the limitation on creating new roads and the standards for using private roads, as road access can change the view characteristics of an area.

MM 4.1-1 The Applicant shall use existing public access easements or county maintained roads to access oil production areas~~, or shall construct new roads (or extend existing roads) to minimize the amount of disturbance without impeding existing surface use~~. Existing private roads may only be used with the written permission of the property owner or private easement holder and written permission is only required if the surface owner is different from the mineral owner. The property owner's signature on the site plan statement will be considered permission for the use of all private roads shown on the site plan.

New roads shall only be created if no existing public access easement exists for access to the oil production area or permission for legal use of an existing private access easement or private driveway/road cannot be obtained. Evidence that legal permission to use a private access or private driveway/road cannot be obtained shall be through two attempts by certified letter to the easement owner with two week reply times for each attempt. No response shall constitute lack of agreement to use the private access easement or private driveway/road.

Permission for use of a private access, instead of the signature on the site plan, shall be from the property owner with a copy of the private easement or, in the case of a private driveway/road a highlighted plot plan showing the driveway/road being approved for use. Any new road shall not exceed 40 feet in graded width.

Clarified MM 4.1-4

MM 4.1-4 requires word modifications to specifically delineate the visual screening required.

MM 4.1-4 Except where located within agricultural land, new oil or gas tanks located within 200 feet of any sensitive receptor shall be partially screened from public view by shrubs, trees or solid screen fencing. Similarly, new pump sites (including multiple well pump sites) within 500 feet of any dwelling must be surrounded by a fence, at least 6 feet in height, constructed of dark-colored chain-link with wood or metal slates, dark green or brown fabric material, or solid wall.~~ other more~~

~~visually restrictive fencing material~~ The height of all new pumping units shall not exceed 80 feet, and shall be painted in accordance with the Kern County Zoning Ordinance.

Clarified MM 4.1-5

MM 4.1-5 includes additional wording that is not needed since the adopted Kern County 19.84.135 Zoning Ordinance has the necessary details for implementation.

MM 4.1-5 Project signage is limited to directional, warning, safety, security and identification signs in connection with oil, gas, or other hydrocarbon drilling and development operations in accordance with Chapter 19.84.135 of the Kern County Zoning Ordinance. ~~For any signage necessary for wayfinding, safety, or security, the Applicant shall use the minimum necessary to adequately communicate the required information.~~

Clarified MM 4.1.6

MM 4.1-6 includes additional wording that is not needed since the adopted Kern County Chapter 19.81 Outdoor Lighting "Dark Sky Ordinance" has the necessary details for implementation.

MM 4.1-6 All new lighting, including permanent nighttime lighting, safety, security, and operational lightening shall comply with the standards in Kern County Zoning Chapter 19.81 - Outdoor Lighting "Dark Sky Ordinance. ~~Permanent nighttime lighting that will be installed for new facility operations will only be lighting required for safety or security. During operations when the lighting is in use, lighting for safety and security will be shielded and oriented downward, bare bulbs will be fully screened from view from sensitive viewing receptors such as residences, and on-demand lighting and/or timers will be used to minimize visual impacts of lighting. In doing so, the Applicant shall comply with the standards in the amended Chapter 19.81 - Outdoor Lighting "Dark Sky Ordinance."~~

MM 4.1-2 and MM 4.1-3 are not recommended for modification from the 2015 FEIR Mitigation Monitoring Program and are included for recommended adoption.

Mitigation Measures

MM 4.1-1 The Applicant shall use existing public access easements or county maintained roads to access oil production areas. Existing private roads may only be used with the written permission of the property owner or private easement holder and written permission is only required if the surface owner is different from the mineral owner. The property owner's signature on the site plan statement will be considered permission for the use of all private roads shown on the site plan.

New roads shall only be created if no existing public access easement exists for access to the oil production area or permission for legal use of an existing private access easement or private driveway/road cannot be obtained. Evidence that legal permission to use a private access or private driveway/road cannot be obtained shall be through two attempts by certified letter to the easement owner with two week reply times for each attempt. No response shall constitute lack of agreement to use the private access easement or private driveway/road.

Permission for use of a private access instead of the signature on the site plan shall be from the property owner with a copy of the private easement or, in the case of a private driveway/road a highlighted plot plan showing the driveway/road being approved for use. Any new road shall not exceed 40 feet in graded width.

MM 4.1-2 All derricks, boilers, and other drilling equipment used to drill, repair, clean out, deepen or redrill any well with oil, gas, or other hydrocarbon shall be removed from the drill site within 90 days after completion of production tests or after abandonment of any well. Earthen sumps used in drilling shall be filled within 90 days after any well has been placed in production (unless such sumps are to be used within six months for the drilling of another well), and any sump used in productions shall be filled after its abandonment and restored to a uniform grade within ninety days.

MM 4.1.3 Sumps and ponds shall be permitted only to the extent authorized by the Central Valley Regional Water Quality Control Board (via waiver, Waste Discharge Requirements, or other form of authorized written documentation) and shall comply with all applicable legal requirements and mitigation measures for sumps serving as storage, percolation or evaporation ponds for produced water.

MM 4.1-4 Except where located within agricultural land, new oil or gas tanks located within 200 feet of any sensitive receptor shall be partially screened from public view by shrubs, trees or solid screen fencing. Similarly, new pump sites (including multiple well pump sites) within 500 feet of any dwelling must be surrounded by a fence, at least 6 feet in height, constructed of dark-colored chain-link with wood or metal slates, dark green or brown fabric material or solid wall. The height of all new pumping units shall not exceed 80 feet, and shall be painted in accordance with the Kern County Zoning Ordinance.

MM 4.1-5 Project signage is limited to directional, warning, safety, security and identification signs in connection with oil, gas, or other hydrocarbon drilling and development operations in accordance with Chapter 19.84.135 of the Kern County Zoning Ordinance.

MM 4.1-6 All new lighting, including permanent nighttime lighting, safety, security, and operational lightening shall comply with the standards in Kern County Zoning Chapter 19.81 - Outdoor Lighting "Dark Sky Ordinance."

Level of Significance after Mitigation

With mitigation, impacts would be reduced; however, since oil and gas activities would continue to produce visible changes to the existing environment, aesthetic impacts would remain, both on a project and cumulative level, significant and unavoidable after mitigation. No additional feasible mitigation measures exist to avoid or reduce significant adverse project or cumulative impacts to aesthetics to less than significant levels.

4.18.1.2 Biological Resources

The 2015 FEIR (Section 4.4, Biological Resources) included MMs 4.4-1 to 4.4 19 to avoid, minimize, and mitigate the biological impacts of the Project to less than significant levels, but cumulative biological impacts remained significant based on other foreseeable land disturbance activities in the Project area. The 2015 FEIR included MM. 4.1-13 for protective measures for plants, which was removed as redundant with the wording of MM 4.4.-12. The recommended mitigation measures have been renumbered to reflect that action. These biological resource mitigation measures were also informed by consultations with expert agencies, including the California Department of Fish and Wildlife (CDFW). The following biological resource mitigation measures are proposed to be modified to increase clarity and improve implementation of the Ordinance.

Clarified MM 4.4-1

MM 4.4-1 The applicant shall use a qualified biologist for all work on reports submitted for any application for project permit. The qualified biologist must have a Bachelor of Science Degree or Bachelor of Arts Degree in biology or related environmental science, have demonstrated familiarity with the natural history, habitat affinities, and identification of Covered Species of the San Joaquin Valley and have conducted work in California for at least one (1) year of field level reconnaissance survey work in the San Joaquin Valley. The resume of the biologist preparing any report submitted for permits shall be included in the report. Lack of these specific qualifications will result in immediate rejection of the report without further review.

A qualified biologist shall conduct a biological reconnaissance survey in potential special-status species habitat to advise the project proponent of potential project impacts, potential surveying needs, and advise on the need for focused special status surveys. Early consultation with United States Fish and Wildlife Service and California Department of Fish and Wildlife ~~would confirm of the biologist's advice and/or~~ will also inform project proponents of additional recommendations. Based on the information gathered from the biological reconnaissance survey and any informal consultation with United States Fish and Wildlife Service and California Department of Fish and Wildlife, focused/protocol surveys shall be conducted by a qualified ~~or permitted~~ biologist ~~(whichever is applicable)~~ ~~well~~ consistent with protocol study timelines, in advance of submittal of the permit application ~~of ground disturbing activities~~ to determine the presence/absence of sensitive species protected by state and federal Endangered Species Acts and potential project impacts to those species. No ground disturbance activities can occur on any well site without an approved Oil and Gas permit. The survey shall be conducted in accordance with the most current standard protocol of the United States Fish and Wildlife Service and California Department of Fish and Wildlife. The purpose of focused/protocol surveys is to confirm the presence or absence of any species listed as threatened or endangered under the federal Endangered Species Act. threatened or endangered under the California Endangered Species Act, rare or endangered in the California Native Plant Protection Act, or designated as fully-protected in the California Fish and Game Code (collectively, "Protected Species"), and to confirm the presence or absence of any other species considered "sensitive" under California Environmental Quality Act ("Sensitive Species"), and to identify and implement ~~feasible~~ avoidance and minimization measures for such species. The surveys shall be conducted in accordance with all currently-applicable presence and absence survey and/or species protocols established by the United States Fish and Wildlife Service and the California Department of Fish and Wildlife ("Species Protocols"). In the absence of any approved protocols, the survey shall extend for a minimum of 250 feet from all areas where any ground disturbance activities would occur, provided that permission to access has been obtained. As an alternative to individual pre-disturbance surveys for each application, and after consultation with and concurrence by the California Department of Fish and Wildlife and the United States Fish and Wildlife Service, multiple parcels or areas of oil and gas production lands (including lands which may have multiple surface or mineral ownership) may be consolidated for the purpose of more efficiently managing pre-disturbance surveys and determinations regarding the absence of protected species in areas of proposed new ground disturbance activities. A biological monitor with the same qualifications as a qualified biologist shall be present during ground-disturbing activities in project locations that have special-status species habitat or are adjacent to potential special-status species habitat. Within 30 days before any ground-disturbing activities in special-status species habitat, ~~a~~ the qualified biologist shall conduct a pre-disturbance survey to record existing conditions of the site, determine if conditions have changed since the reconnaissance or focused/protocol surveys were conducted, and to determine where sensitive species avoidance buffers will be established

Clarified MM 4.4-3

MM 4.4-3 Protective buffers shall be used, where effective ~~and feasible~~ in the opinion ~~and guidance~~ of the qualified biologist, to avoid any unauthorized incidental take of Protected Species, and to minimize any incidental take of Sensitive Species, by separating the planned disturbance area from any locations where the qualified biologist ~~biological reconnaissance surveys, previously conducted focused/protocol surveys, or pre-disturbance surveys have~~ has detected the presence of Protected Species or Sensitive Species. Protective buffers shall be delineated using brightly colored stakes and/or flagging or similar materials and remain until construction activities are complete, at which time of completion the buffers must be removed. ~~If special status plant or animal species are found adjacent to the project during biological surveys,~~ Protective buffers shall be established around active dens and/or burrows of special-status animal species, or populations of special-status plant species to avoid unauthorized take of protected species as listed in the table below. The protective buffer distance shall be increased if required to avoid unauthorized incidental take of any Protected Species as determined by a qualified biologist. Protective buffer distances and other avoidance measures that may be implemented to avoid impacts to Protected Species or Sensitive Species must be consistent with the United States Fish and Wildlife Service and/or the California Department of Fish and Wildlife, and shall be implemented and overseen by ~~a~~ the qualified biologist.

Table: Disturbance Buffers for Sensitive Resources

Sensitive Resource	**Buffer Zone from Disturbance (feet)**
Potential San Joaquin kit fox den	50
Known San Joaquin kit fox den	100
Natal San Joaquin kit fox den	~~Contact California Department of Fish and Wildlife, United States Fish and Wildlife Services~~ 500
Atypical San Joaquin kit fox den	50
Rodent burrows	50
Listed bird species active nests	0.5 mile
Burrowing owl burrow (breeding and non-breeding season)	Pursuant to California Department of Fish & Wildlife guideline (see Table 4.4-85)
San Joaquin coachwhip, silvery legless lizard, coast horned lizard	30
American badger: Non-maternity dens Maternity dens	 50 200
Special-status plants	50

Clarified MM 4.4-5

MM 4.4-5 The qualified biologist surveys ~~The pre-disturbance surveys~~ shall determine whether active bat maternity roosts are located in or within 250 feet of any disturbance area. All active bat maternity roosts shall be avoided during breeding periods, including postponing disturbance activities. ~~if required, and to the maximum extent feasible at other times.~~ If an active Sensitive or Protected Species bat maternity roost location is proposed to be disturbed the qualified biologist shall consult with ~~cannot feasibly be avoided by disturbance,~~ the United States Fish and Wildlife Service and California Department of Fish and Wildlife to identify any additional minimization measures which the qualified biologist determines with the wildlife agencies can actually be implemented based on field conditions. All such measures must be implemented for project activities. ~~must be contacted to identify appropriate impact minimization measures prior to initiating any disturbance that would affect the roost~~

Clarified MM 4.4-6

MM 4.4-6 Any potential San Joaquin kit fox dens (as defined in United States Fish and Wildlife Service 2011a) detected during reconnaissance or focused/protocol surveys shall be reevaluated by the qualified biologist for species activity no more than 30 days prior to the commencement of ground disturbance in the required pre-construction survey. Potential kit fox dens shall be marked and a 50-foot avoidance buffer shall be delineated using brightly colored stakes and flagging or similar materials to prevent inadvertent damage to the potential den. If the qualified biologist determines that an unoccupied ~~a~~ potential den cannot ~~feasibly~~ be avoided, the den may be hand excavated in accordance with the United States Fish and Wildlife Service Standardized Recommendations for Protection of the Endangered San Joaquin Kit Fox Prior to or During Ground Disturbance (United States Fish and Wildlife Service 2011). If species activity is detected, the location shall be identified as a "known" kit fox den in accordance with the U.S. Fish and Wildlife Service species guidelines (United States Fish and Wildlife Service 2011). A minimum 100-foot buffer from any disturbance area shall be maintained for known dens and a minimum 500-foot buffer from any disturbance area shall be maintained for natal dens. No excavation of a known or natal den shall occur without prior authorization from the United States Fish and Wildlife Service and the California Department of Fish and Wildlife. For activities occurring on land covered under an approved federal and/or State incidental take authorization, the requirements set forth in those documents shall be implemented. Other standard measures to protect San Joaquin kit fox, including capping pipes, covering trenches, adding exit ramps to excavated areas, shall be implemented in accordance with MM 4.4-15.

Clarified MM 4.4-7

MM 4.4-7 Occupied American badger dens detected during pre-disturbance surveys shall be flagged and ground-disturbing activities avoided within 50 feet of the den. Maternity dens shall be avoided and a minimum 200-foot buffer from disturbance shall be maintained during pup-rearing season (February 15 through July 1). Maternity dens must be avoided to the maximum extent feasible in the opinion of the qualified biologist. If an active maternity den is proposed to be disturbed, the qualified biologist ~~cannot feasibly be avoided~~, shall consult with the California Department of Fish and Wildlife ~~must be contacted~~ to identify any appropriate additional ~~impact~~ minimization measures which the qualified biologist determines, with the wildlife agencies, can actually be implemented based on field conditions. All such measures must be implemented for project activities ~~prior to initiating any disturbance that would affect the den, including potential passive relocation by excavation before or after the rearing season.~~

Clarified MM 4.4-9

MM. 4.4-9 All sites located above 2,000 feet in elevation, or within 200 feet down gradient from the 2,000-foot elevation contour line, shall implement the following measures to avoid and minimize potential adverse impacts to the California condor:

a. The site shall, at all times, be maintained to avoid any trash, debris, food sources and microtrash, such as bottle caps, that could be ingested by or attract California condor. Trash shall be disposed in animal-proof containers as required in MM 4.4-19.

b. The Worker Environmental Awareness Program described in MM 4.4-18 shall include information about microtrash and potential effects to California condor, and shall prohibit the disposal of trash and microtrash on the site of oil and gas activities.

c. If a condor is observed in a proposed construction site, all disturbance activities must immediately cease within 500 feet of the condor until the animal has moved from the site. If condor occurrence persists, the United States Fish and Wildlife Service and the California Department of Fish and Wildlife must be contacted to identify appropriate avoidance measures and those measures must be implemented by the qualified biologist used by the applicant. prior to initiating or resuming any disturbance activity.

d. All condor observations shall be reported within 24 hours to the United States Fish and Wildlife Service and the California Department of Fish and Wildlife.

e. All tanks, liquid storage facilities, and any open area containing water or other liquid materials, including drilling sumps, must be covered or otherwise shielded in a manner that prevents condor intrusion and potential entrapment.

f. No overhead transmission lines may be used at the site without the prior approval of the United States Fish and Wildlife Service and the California Department of Fish and Wildlife.

Clarified MM 4.4-10

MM 4.4-10 Pre-disturbance surveys for active bird nests must be conducted no more than 10 days prior to the commencement of disturbance. Surveys shall follow United States Fish and Wildlife and California Department of Fish and Wildlife guidance and/or protocols, as applicable. If no active nests or nesting birds are identified, then Project construction activities may proceed and no further mitigation measures for nesting birds are required. If active nest(s) are identified, the active nest(s) should be continuously surveyed for the first 24 hours after detection, to establish a behavioral baseline prior to any construction-related activities.

Once construction commences, all nests shall be continuously monitored to detect any behavioral changes as a result of the Project (i.e., nest avoidance or abandonment). If behavioral changes are observed, the work causing that change ~~should~~ shall cease until the applicant qualified biologist consults with ~~and~~ the

California Department of Fish and Wildlife and the United States Fish and Wildlife and the qualified biologist used by the applicant implements the recommended measures. ~~should be consulted for additional avoidance and minimization measures.~~ During such times as the qualified biological monitor is not onsite while construction workers are onsite, ~~If continuous monitoring of identified nests by a qualified wildlife biologist is not feasible,~~ a minimum no disturbance buffer of 250 feet ~~will~~ shall be established around active nests and a 500-foot no-disturbance buffer around the nests of raptors until the breeding season has ended, or until a qualified biologist has determined that the birds have fledged and are no longer reliant upon the nest or parental care for survival, and any adult birds are no longer occupying the nest. ~~Variance~~ Deviations from these nondisturbance buffers may be implemented if the qualified biologist concludes that work within the buffer area would not cause nest avoidance or abandonment (e.g., when the disturbance area would be concealed from a nest site by topography) provided that notification of this determination of a deviation in the no-disturbance buffer is provided by the qualified biologist no less than 15 days in advance to the ~~The~~ California Department of Fish and Wildlife and the United States Fish and Wildlife ~~must be notified in advance of implementing of a variance in the no-disturbance buffer.~~

Clarified MM 4.4-12

MM 4.4-12 The Applicant shall comply with the following:

a. Plant surveys for Protected Species and Sensitive Species must be completed by a qualified biologist during the appropriate blooming periods for species identification and detection. Plant surveys shall be conducted in accordance with all applicable protocols established by the United States Fish and Wildlife Service and the California Department of Fish and Wildlife for particular plant species ("Plant Survey Protocol"), and shall extend 50 feet from areas where any new disturbance would occur unless a greater survey distance is specified in the Plant Survey Protocol. All detected plant populations of Protected Species and Sensitive Species shall be identified in the field during the surveys with temporary flags or other ~~appropriate~~ visible materials to avoid and minimize impacts to the plant populations from any disturbance activities.

b. No incidental take or relocation of any plant listed under the federal Endangered Species Act, the California Endangered Species Act, or the California Native Plant Protection Act may occur unless the incidental take is authorized by the United States Fish and Wildlife Service and/or the California Department of Fish and Wildlife in a permit or other authorization, or in an approved Habitat Conservation Plan or Natural Communities Conservation Plan. If focused plan surveys detect the presence of any listed plant, the plant populations shall be buffered from disturbance activities by implementing applicable impact avoidance protocols established by the United States Fish and Wildlife Service and/or the California Department of Fish and Wildlife unless incidental take authority is obtained. Projects covered under incidental take authority shall conduct activities in accordance with the take authorization. The qualified biologist may consult with the California Department of Fish and Wildlife to determine the recommended ~~may be contacted to determine the appropriate~~ buffer distances required to prevent incidental take of a listed plant if avoidance protocols have not been established for the species. The qualified biologist shall confirm that all applicable listed plant buffers have been implemented prior to the commencement of any disturbance activity.

c. ~~If any non-listed sensitive plant species are identified~~ Sensitive species plant populations which are not Protected Species that may be impacted by new ground disturbing activities, ~~populations~~ must be avoided by a 50-foot buffer, as delineated and implemented by a qualified biologist used by the applicant.

Clarified MM 4.4-15 (renumbered to MM 4.4-14)

MM 4.4-14 The following additional measures shall be implemented to avoid and minimize potential significant adverse impacts to Protected and Sensitive Species:

a. All vehicles shall observe a 20-mile-per-hour speed limit in all areas of disturbance and on unpaved roads unless otherwise posted. Off-road traffic outside of designated access routes is prohibited. Speed limit signs shall be posted in visible locations at the point of site entry and at regular intervals on all unpaved access roads.

b. All disturbance activities, except emergency situations or drilling that may require continuous operations, shall only occur during daylight hours. Night time disturbance activity for drilling purposes shall use directed lighting, shielding methods~~or reduced lumen intensity to avoid unnecessary visual disturbance to wildlife~~ and to comply with applicable lighting mitigation measures.

c. All food-related trash items and all forms of microtrash, such as wrappers, cans, bottles, bottle tops, and food scraps shall be disposed of in closed, animal proof containers and removed daily from the site.

d. Excavations, spoils piles, access roadways, and parking and staging areas shall subject to dust control as set forth in the dust control mitigation measures.

e. The use of herbicides for vegetation control shall be restricted to those approved by the United States Fish and Wildlife Service and the California Department of Fish and Wildlife. No rodenticides shall be used on any site unless approved by the United States Fish and Wildlife Service, and the California Department of Fish and Wildlife, and shall observe label and other restrictions mandated by the United States Environmental Protection Agency, California Department of Food and Agriculture, and state and federal laws and regulations. For split estates, no herbicides for vegetation control may occur in Tier 2 areas without surface owner approval.

f. No plants or wildlife shall be collected, taken, or removed from the site or any adjacent locations except as necessary for Project-related vegetation removal or wildlife relocation by a qualified biologist and subject to all applicable permits and authorizations.

g. All open trenches or excavations shall be covered at the end of each workday to prevent wildlife entrapment. If an excavation is too large to cover, escape ramps shall be installed at an incline ratio of no greater than 2: 1. All trenches and pipes shall be inspected for the presence of wildlife each day prior to the commencement of work.

h. To enable San Joaquin kit foxes and other wildlife to pass through the Project site, any perimeter fencing shall include a 4- to 8-inch opening between the fence mesh and the ground or the fence shall be raised 4 inches above the ground except blunt-nosed leopard lizard exclusion fencing. The bottom of the fence fabric shall be knuckled (wrapped back to form a smooth edge) to protect wildlife.

i. All vertical tubes used in Project construction and chain link fencing poles, shall be temporarily or permanently capped to avoid the entrapment and death of special-status wildlife and birds. All pipes 1.5 inches or greater in diameter stored overnight on a project location must have end caps or other physical barriers that prevent wildlife from entering the pipe.

j. All dead or injured special status wildlife shall be left in place and reported to the United States Fish and Wildlife Service and the California Department of Fish and Wildlife within 48 hours of discovery for rescue or salvage. Discovery of state or federal listed species that are injured or dead shall also be managed consistent with regulatory requirements, including being reported immediately via telephone and within 24 hours in writing, and with a copy to Kern County Planning and ~~Community Development~~ Natural Resources.

k. All drilling installations and operations will comply at all times with the applicable federal, State, county, and local law ordinances and regulations.

l. During pre-construction surveys, the qualified biologist shall delineate ~~All activity shall use~~ previously disturbed areas to be used by the applicant to minimize ~~to the maximum extent feasible to minimize~~ the amount of new disturbance.

m. All concrete and asphalt debris should be removed from the site for recycling or ~~proper~~ disposal at an authorized, permitted facility.

n. No vehicles or construction equipment shall be parked within a wetland or waterbody/dry wash.

o. Tracked vehicles and other construction equipment must be washed or maintained to be weed-free prior to entering and working within areas of new disturbance.

p. All washing of trucks, paint, equipment, or similar activities should occur in areas where runoff is fully contained for collection and offsite disposal. Wash water may not be discharged from the site and shall be located at least 100 feet from any water body, or sensitive Biological Resources.

q. Locate all extra work areas (such as staging areas and additional spoil storage areas) at least 50 feet away from wetland boundaries or waterbody, except where the adjacent upland consists of cultivated or rotated cropland or other disturbed land.

r. All areas that must be avoided as result of the pre-disturbance surveys, and areas where new disturbance will occur, shall be clearly delineated by fencing or staking and flagging and/or rope or cord.

s. No firearms shall be allowed on any site.

t. No pets shall be allowed on any site.

u. No smoking may occur except in designated areas.

v. If ground disturbance is intended to be temporary and does not occur on cultivated and crop lands, perform topsoil segregation during construction activities to preserve the seed bank for restoration efforts. Store the segregated topsoil separate from the subsoil and restore segregated topsoil to its original location.

Clarified MM 4.4-19 (renumbered to 4.4-18)

MM 4.4-~~19~~18 In the event that new disturbance would occur at a site within an oak woodland area as defined in Section 1.10.10 of the Kern County General Plan Land Use, Open Space and Conservation Element (10% or greater oak tree cover), the Applicant shall comply with the minimum 30% canopy retention standard in Section 1.10.10 KK (a). ~~Impacts to oak trees in other locations, and in locations that meet the criteria for an oak woodland area, shall be avoided to the maximum extent practicable, including modification of the disturbance area, if feasible, to avoid existing oak trees within a site.~~

Mitigation Measures

MM 4.4-1 The applicant shall use a qualified biologist for all work on reports submitted for any application for project permit. The qualified biologist must have a Bachelor of Science Degree or Bachelor of Arts Degree in biology or related environmental science, have demonstrated familiarity with the natural history, habitat affinities and identification of Covered Species of the San Joaquin Valley and have conducted work in California for at least one (1) year of field level reconnaissance survey work in the San Joaquin Valley. The resume of the biologist preparing any report submitted for permits shall be included in the report. Lack of theses specific qualifications will result in immediate rejection of the report without further review.

A qualified biologist shall conduct a biological reconnaissance survey in potential special-status species habitat to advise the project proponent of potential project impacts, potential surveying needs, and advise on the need for focused special status surveys. Early consultation with United States Fish and Wildlife Service and California Department of Fish and Wildlife will also inform project proponents of additional recommendations. Based on the information gathered from the biological reconnaissance survey and any informal consultation with United States Fish and Wildlife Service and California Department of Fish and Wildlife, focused/protocol surveys shall be conducted by a qualified biologist consistent with protocol study timelines in advance of submittal of the permit application to determine the presence/absence of sensitive species protected by state and federal Endangered Species Acts and potential project impacts to those species. No ground disturbance activities can occur on any well site without an approved Oil and Gas permit. The survey shall be conducted in accordance with the most current standard protocol of the United States Fish and Wildlife Service and California Department of Fish and Wildlife. The purpose of focused/protocol surveys is to confirm the presence or absence of any species listed as threatened or endangered under the federal Endangered Species Act. threatened or endangered under the California Endangered Species Act, rare or endangered in the California Native Plant Protection Act, or designated as fully-protected in the California Fish and Game Code (collectively, "Protected Species"), and to confirm the presence or absence of any other species considered "sensitive" under California Environmental Quality Act ("Sensitive Species"), and to identify and implement avoidance and minimization measures for such species. The surveys shall be conducted in accordance with all currently-applicable presence and absence survey and/or species protocols established by the United States Fish and Wildlife Service and the California Department of Fish and Wildlife ("Species Protocols"). In the absence of any approved protocols, the survey shall extend for a minimum of 250 feet from all areas where any ground disturbance activities would occur, provided that permission to access has been obtained. As an alternative to individual pre-disturbance surveys for each application, and after consultation with and concurrence by the California Department of Fish and 'Wildlife and the United States Fish and Wildlife Service, multiple parcels or areas of oil and gas production lands (including lands which may have multiple surface or mineral ownership) may be consolidated for the purpose of more efficiently managing pre-disturbance surveys and determinations regarding the absence of protected species in areas of proposed new ground disturbance activities. A biological monitor with the same qualifications as a qualified biologist shall be present during ground-disturbing activities in project locations that have special-status species habitat or are adjacent to potential special-status species habitat. Within 30 days before any ground-disturbing activities in special-status species habitat, the qualified biologist shall conduct a pre-disturbance survey to record existing conditions of the site, determine if conditions have changed since the reconnaissance or focused/protocol surveys were conducted, and to determine where sensitive species avoidance buffers will be established

MM 4.4-2 No incidental take of any species listed as threatened or endangered under the federal Endangered Species Act, threatened or endangered under the California Endangered Species Act, rare or endangered in the California Native Plant Protection Act, or designated as fully protected in the California Fish and Game Code (Protected Species) may occur unless the incidental take is authorized by applicable state and federal wildlife agencies in the form of a permit or other written authorization, an approved state or federal conservation plan, or in accordance with an approved regional plan such as the Draft Valley Floor Habitat Conservation Plan and/or Natural Community Conservation Plan.

MM 4.4-3 Protective buffers shall be used, where effective in the opinion of the qualified biologist, to avoid any unauthorized incidental take of Protected Species, and to minimize any incidental take of Sensitive Species, by separating the planned disturbance area from any locations where the qualified biologist has detected the presence of Protected Species or Sensitive Species. Protective buffers shall be delineated using brightly colored stakes and/or flagging or similar materials and remain until construction activities are complete, at which time of completion the buffers must be removed. Protective buffers shall be established around active dens and/or burrows of special-status animal species, or populations of special-status plant species to avoid unauthorized take of protected species as listed in the table below. The protective buffer distance shall be increased if required to avoid unauthorized incidental take of any Protected Species as determined by a qualified biologist. Protective buffer distances and other avoidance measures that may be implemented to avoid impacts to Protected Species or Sensitive Species must be consistent with the United States Fish and Wildlife Service and/or the California Department of Fish and Wildlife, and shall be implemented and overseen by the qualified biologist.

Table: Disturbance Buffers for Sensitive Resources

Sensitive Resource	**Buffer Zone from Disturbance (feet)**
Potential San Joaquin kit fox den	50
Known San Joaquin kit fox den	100
Natal San Joaquin kit fox den	500
Atypical San Joaquin kit fox den	50
Rodent burrows	50
Listed bird species active nests	0.5 mile
Burrowing owl burrow (breeding and non-breeding season)	Pursuant to California Department of Fish & Wildlife guideline (see Table 4.4-85)
San Joaquin coachwhip, silvery legless lizard, coast horned lizard	30
American badger: Non-maternity dens Maternity dens	 50 200
Special-status plants	50

MM 4.4-4 Occupied burrowing owl burrows shall not be disturbed during the species nesting season (February 1 through August 31). The following distances shall be maintained between all disturbance areas and burrowing owl nesting sites (Table 4.4-85).

Table 4.4-85 Setback Distances for Burrowing Owl Nesting Sites by Level of Proposed Project Impacts

Location		
Nesting sites	Nesting sites	Nesting sites
Time of Year		
April 1–Aug 15	**Aug 16–Oct 15**	**Oct 16–Mar 31**
Project Impact Level		
Low		
656 feet (200 meters)	656 feet (200 meters)	164 feet (50 meters)
Medium		
1,640 feet (500 meters)	656 feet (200 meters)	328 feet (100 meters)
High		
1,640 feet (500 meters)	1,640 feet (500 meters)	1,640 feet (500 meters)

Burrowing owls present in proposed disturbance areas or within 500 feet or as specified under an approved Habitat Conservation Plan (as identified during pre-disturbance surveys) outside of the breeding season (between September 1 and January 31) may be moved away from the disturbance area using passive relocation techniques approved by the California Department of Fish and Wildlife. Passive relocation techniques in the California Department of Fish and Wildlife *Staff Report on Burrowing Owl Mitigation Guidelines* (California Department of Fish and Game 2012) include installing one-way doors in burrow entrances for 48 hours, to ensure the owl(s) have left the burrow, daily monitoring during the passive relocation period, and collapsing existing burrows to prevent reoccupation. A minimum of one or more weeks will be required to relocate the owl(s) and allow for acclimatization to alternate off-site burrows. Prior to burrow exclusion or eviction, a burrowing owl management plan shall be prepared and approved by the California Department of Fish and Wildlife. Destruction of burrows shall occur only pursuant to a management plan for the species approved by the California Department of Fish and Wildlife; burrow excavation shall be conducted by hand whenever possible.

As an alternative to passive relocation, occupied burrows identified off-site within 500 feet of construction activities may be buffered with hay bales, fencing (e.g. sheltering in place), or as directed by the qualified biologist and the California Department of Fish and Wildlife, to avoid disturbance of burrows.

MM 4. 4-5 The qualified biologist surveys shall determine whether active bat maternity roosts are located in or within 250 feet of any disturbance area. All active bat maternity roosts shall be avoided during breeding periods, including postponing disturbance activities. If an active Sensitive or Protected Species bat maternity roost location is proposed to be disturbed, the qualified biologist shall consult with, the United States Fish and Wildlife Service and California Department of Fish and Wildlife to identify any additional minimalization measures which the qualified biologist determines with the wildlife agencies can actually be implemented based on field conditions. All such measures must be implemented for project implementation.

MM 4.4-6 Any potential San Joaquin kit fox dens (as defined in United States Fish and Wildlife Service 2011a) detected during reconnaissance or focused/protocol surveys shall be reevaluated by the qualified biologist for species activity no more than 30 days prior to the commencement of ground disturbance in the required pre-construction survey. Potential kit fox dens shall be marked and a 50-foot avoidance buffer shall be delineated using brightly colored stakes and flagging or similar materials to prevent inadvertent damage to the potential den. If the qualified biologist determines that an unoccupied ~~a~~ potential den cannot be avoided, the den may be hand excavated in accordance with the United States Fish and Wildlife Service Standardized Recommendations for Protection of the Endangered San Joaquin Kit Fox Prior to or During Ground Disturbance (United States Fish and Wildlife Service 2011). If species activity is detected, the location shall be identified as a "known" kit fox den in accordance with the U.S. Fish and Wildlife Service species guidelines (United States Fish and Wildlife Service 2011). A minimum 100-foot buffer from any disturbance area shall be maintained for known dens and a minimum 500-foot buffer from any disturbance area shall be maintained for natal dens. No excavation of a known or natal den shall occur without prior authorization from the United States Fish and Wildlife Service and the California Department of Fish and Wildlife. For activities occurring on land covered under an approved federal and/or State incidental take authorization, the requirements set forth in those documents shall be implemented. Other standard measures to protect San Joaquin kit fox, including capping pipes, covering trenches, adding exit ramps to excavated areas, shall be implemented in accordance with MM 4.4-15.

MM 4.4-7 Occupied American badger dens detected during pre-disturbance surveys shall be flagged and ground-disturbing activities avoided within 50 feet of the den. Maternity dens shall be avoided and a minimum 200-foot buffer from disturbance shall be maintained during pup-rearing season (February 15 through July 1). Maternity dens must be avoided to the maximum extent feasible in the opinion of the qualified biologist. If an active maternity den is proposed to be disturbed, the qualified biologist, shall consult with the California Department of Fish and Wildlife to identify any appropriate additional minimization measures which the qualified biologist determines, with the wildlife agencies, can actually be implemented based on field conditions. All such measures must be implemented for project implementation.

MM 4.4-8 Pre-disturbance surveys for all sites located above 2,000 feet in elevation, or within 200 feet down gradient from the 2,000-foot elevation contour line, shall specifically survey for any golden eagle nests located within 2 miles of the site. If golden eagle nests are detected by the surveys, the qualified biologist shall conduct a nest-specific viewshed analysis. No disturbance may occur within 0.25 mile, or within 0.5 mile of the viewshed of an active golden eagle nest unless otherwise authorized by State and federal wildlife agencies. The United States Fish and Wildlife Service and California Department of Fish and Wildlife must be notified prior to the commencement of any disturbance activities within 1 mile of an active golden eagle nest to avoid golden eagle take.

MM. 4.4-9 All sites located above 2,000 feet in elevation, or within 200 feet down gradient from the 2,000-foot elevation contour line, shall implement the following measures to avoid and minimize potential adverse impacts to the California condor:

a. The site shall, at all times, be maintained to avoid any trash, debris, food sources and microtrash, such as bottle caps, that could be ingested by or attract California condor. Trash shall be disposed in animal-proof containers as required in MM 4.4-19.

b. The Worker Environmental Awareness Program described in MM 4.4-18 shall include information about microtrash and potential effects to California condor, and shall prohibit the disposal of trash and microtrash on the site of oil and gas activities.

c. If a condor is observed in a proposed construction site, all disturbance activities must immediately cease within 500 feet of the condor until the animal has moved from the site. If condor occurrence persists, the United States Fish and Wildlife Service and the California Department of Fish and Wildlife must be contacted to identify appropriate avoidance measures and those measures must be implemented by the qualified biologist used by the applicant. prior to initiating or resuming any disturbance activity.

d. All condor observations shall be reported within 24 hours to the United States Fish and Wildlife Service and the California Department of Fish and Wildlife.

e. All tanks, liquid storage facilities, and any open area containing water or other liquid materials, including drilling sumps, must be covered or otherwise shielded in a manner that prevents condor intrusion and potential entrapment.

f. No overhead transmission lines may be used at the site without the prior approval of the United States Fish and Wildlife Service and the California Department of Fish and Wildlife.

MM 4.4-10 Pre-disturbance surveys for active bird nests must be conducted no more than 10 days prior to the commencement of disturbance. Surveys shall follow United States Fish and Wildlife and California Department of Fish and Wildlife guidance and/or protocols, as applicable. If no active nests or nesting birds are identified, then Project construction activities may proceed and no further mitigation measures for nesting birds are required. If active nest(s) are identified, the active nest(s) should be continuously surveyed for the first 24 hours after detection, to establish a behavioral baseline prior to any construction-related activities.

Once construction commences, all nests shall be continuously monitored to detect any behavioral changes as a result of the Project (i.e., nest avoidance or abandonment). If behavioral changes are observed, the work causing that change shall cease until the applicant qualified biologist consults with the California Department of Fish and Wildlife and the United States Fish and Wildlife and the qualified biologist used by the applicant implements the recommended measures. During such times as the qualified biological monitor is not onsite while construction workers are onsite, a minimum nondisturbance buffer of 250 feet shall be established around active nests and a 500-foot no-disturbance buffer around the nests of raptors until the breeding season has ended, or until a qualified biologist has determined that the birds have fledged and are no longer reliant upon the nest or parental care for survival, and any adult birds are no longer occupying the nest. Deviations from these no disturbance buffers may be implemented if the qualified biologist concludes that work within the buffer area would not cause nest avoidance or abandonment (e.g., when the disturbance area would be concealed from a nest site by topography) provided that notification of this determination of a deviation in the no-disturbance buffer is provided by the qualified biologist no less than 15 days in advance to the California Department of Fish and Wildlife and the United States Fish and Wildlife.

MM 4.4-11 The following measures will be implemented to avoid take of blunt-nosed leopard lizard and to ensure protection of these animals during Project activities:

a. Project activities will avoid all potential burrows that may be occupied by blunt-nosed leopard lizards. Suitable burrows within and adjacent to potential habitat for the species should be avoided by a minimum distance of 50-feet in all areas where ground-disturbing Project activities will occur.

b. No more than one year prior to ground disturbing activities, focused surveys following current California Department of Fish and Wildlife and United States Fish and Wildlife protocols for detection of this species or other methods approved by both agencies shall be conducted in all potential blunt-nosed leopard lizard habitat within the work site and a 250-foot buffer area. If no individual blunt-nosed leopard lizards are observed during focused surveys, and surveys are current (e.g., completed in the same calendar year), then Project activities may proceed.

c. If blunt-nosed leopard lizards are detected during focused surveys, a blunt-nosed leopard lizard avoidance plan shall be prepared for the Project that will result in avoidance of incidental take of this species unless take is separately authorized under a Natural Communities Conservation Plan and appropriate federal authorization is obtained. At a minimum, the blunt-nosed leopard lizard avoidance plan shall be provided to the California Department of Fish and Wildlife and the County, and shall contain the following elements:

    1. A Worker Environmental Awareness Program shall be implemented for all construction personnel before construction begins (see MM 4.4-18).

    2. During periods that are optimal for blunt-nosed leopard lizard activity (early spring through late fall), a qualified biologist will be present during

all ground disturbing activities. The qualified biologist will check the Project site(s) and access route(s) daily during the blunt-nosed leopard lizard active season to determine presence or absence of lizards in or near the work areas. Monitoring by a qualified biologist is not required during periods of inactivity (the winter season).

3. All open trenches or excavations shall be covered at the end of each workday or protected with the use of exclusion fencing to prevent wildlife entrapment. If an excavation is too large to cover, escape ramps shall be installed at an incline ratio of no greater than 2:1. All trenches and pipes shall be inspected for the presence of wildlife each day prior to the commencement of work. If blunt-nosed leopard lizards are observed at the work site during construction, construction shall cease within a 250-foot radius and the United States Fish and Wildlife Service and the California Department of Fish and Wildlife shall be consulted to determine what additional measures would be necessary to prevent take of this species.
4. Offsite locations where blunt-nosed leopard lizards have been observed or are likely to occur shall be clearly marked to prevent workers from driving off the road and to prevent inadvertent destruction of burrows. Barriers, such as exclusionary fencing may be installed. All construction equipment and construction personnel vehicles will be checked prior to moving to ensure no blunt-nosed leopard lizard are under equipment/vehicles.
5. A speed limit of 10 miles per hour shall be posted and observed within 0.25 miles of any reported blunt-nosed leopard lizard observation.
6. Construction activities shall avoid burrows that may be used by blunt-nosed leopard lizards. Any location of proposed construction activity with potential to collapse or block burrows (i.e., stockpile storage, parking areas, staging areas, trenches) will be identified prior to construction in the blunt-nosed leopard lizard avoidance plan and approved by the qualified biologist. The qualified biologist may allow certain activities in burrow areas if the combination of soil hardness and activity impact is not expected to collapse burrows and no blunt-nosed leopard lizards have been found during pre-Project surveys in the impact area.
7. All individual blunt-nosed leopard lizards observed above-ground will be avoided. Any individual blunt-nosed leopard lizard that may enter the Project site(s) would be allowed to leave unobstructed, and on its own accord. If a blunt-nosed leopard lizard is detected during biological monitoring or observed at any other point, the California Department of Fish and Wildlife and the United States Fish and Wildlife Service shall be notified to determine what additional measures would be necessary to prevent take of the species.

MM 4.4-12 The Applicant shall comply with the following:

a. Plant surveys for Protected Species and Sensitive Species must be completed by a qualified biologist during the appropriate blooming periods for species identification and detection. Plant surveys shall be conducted in accordance with all applicable protocols established by the United States Fish and Wildlife Service and the California Department of Fish and Wildlife for particular plant species ("Plant Survey Protocol"), and shall extend 50 feet from areas where any new disturbance would occur unless a greater survey distance is specified in the Plant Survey Protocol. All detected plant populations of Protected Species and Sensitive Species shall be identified in the field during the surveys with temporary flags or other visible materials to avoid and minimize impacts to the plant populations from any disturbance activities.

b. No incidental take or relocation of any plant listed under the federal Endangered Species Act, the California Endangered Species Act, or the California Native Plant Protection Act may occur unless the incidental take is authorized by the United States Fish and Wildlife Service and/or the California Department of Fish and Wildlife in a permit or other authorization, or in an approved Habitat Conservation Plan or Natural Communities Conservation Plan. If focused plan surveys detect the presence of any listed plant, the plant populations shall be buffered from disturbance activities by implementing applicable impact avoidance protocols established by the United States Fish and Wildlife Service and/or the California Department of Fish and Wildlife unless incidental take authority is obtained. Projects covered under incidental take authority shall conduct activities in accordance with the take authorization. The qualified biologist may consult with the California Department of Fish and Wildlife to determine the recommended buffer distances required to prevent incidental take of a listed plant if avoidance protocols have not been established for the species. The qualified biologist shall confirm that all applicable listed plant buffers have been implemented prior to the commencement of any disturbance activity.

c. Sensitive species plant populations which are not Protected Species that may be impacted by new ground disturbing activities must be avoided by a 50-foot buffer, as delineated and implemented by a qualified biologist used by the applicant.

MM 4.4- 13 A Worker Environmental Awareness Program shall be developed and implemented for all personnel that could access the site prior to commencing any disturbance activities. The program shall consist of an on-site or center presentation that will describe the locations and types of sensitive plant, wildlife, and sensitive natural communities (collectively, “Biological Resources”) on and near the site, an overview of the laws and regulations governing the protection of Biological Resources, the reasons for protecting the Biological Resources, the specific protection and avoidance measures that are applicable to the site, and the identity of designated points of contact should questions or issues arise, including the qualified biologist. The program shall provide training to recognize, avoid and report to applicable qualified biologists any Biological Resources on the site.

a. The Worker Environmental Awareness Program shall emphasize the need to avoid contact with onsite wildlife, and avoid entry into areas where Biological Resources have been identified based on pre-disturbance field surveys and to implement the buffer avoidance or other protection measures established by the United States Fish and Wildlife Service shall be identified California Department of Fish and Wildlife or required by the Biological Resource mitigation measures. The training shall emphasize the importance of not feeding or domesticating wildlife and the need to avoid any trash, microtrash, or potential food disposal onsite except in animal-proof containers emptied daily to avoid attracting, or causing adverse impacts to special status wildlife.

b. All onsite personnel must sign a statement verifying that they have completed the Worker Environmental Awareness Program, and that they understand and agree to implement the biological requirements for the worksite. If signed employee statements are not available, documentation may be provided by Worker Environmental Awareness Program training records, which shall be kept by the Applicant for a minimum of 5 years. Each Applicant shall maintain a list of all persons who have completed the training program, and shall provide the list to the County or to state and federal wildlife agency representatives upon request.

MM 4.4-14 The following additional measures shall be implemented to avoid and minimize potential significant adverse impacts to Protected and Sensitive Species:

a. All vehicles shall observe a 20-mile-per-hour speed limit in all areas of disturbance and on unpaved roads unless otherwise posted. Off-road traffic outside of designated access routes is prohibited. Speed limit signs shall be posted in visible locations at the point of site entry and at regular intervals on all unpaved access roads.

b. All disturbance activities, except emergency situations or drilling that may require continuous operations, shall only occur during daylight hours. Night time disturbance activity for drilling purposes shall use directed lighting, shielding methods, and comply with applicable lighting mitigation measures.

c. All food-related trash items and all forms of microtrash, such as wrappers, cans, bottles, bottle tops, and food scraps shall be disposed of in closed, animal proof containers and removed daily from the site.

d. Excavations, spoils piles, access roadways, and parking and staging areas shall subject to dust control as set forth in the dust control mitigation measures.

e. The use of herbicides for vegetation control shall be restricted to those approved by the United States Fish and Wildlife Service and the California Department of Fish and Wildlife. No rodenticides shall be used on any site unless approved by the United States Fish and Wildlife Service, and the

California Department of Fish and Wildlife, and shall observe label and other restrictions mandated by the United States Environmental Protection Agency, California Department of Food and Agriculture, and state and federal laws and regulations. For split estates, no herbicides for vegetation control may occur in Tier 2 areas without surface owner approval.

f. No plants or wildlife shall be collected, taken, or removed from the site or any adjacent locations except as necessary for Project-related vegetation removal or wildlife relocation by a qualified biologist and subject to all applicable permits and authorizations.

g. All open trenches or excavations shall be covered at the end of each workday to prevent wildlife entrapment. If an excavation is too large to cover, escape ramps shall be installed at an incline ratio of no greater than 2:1. All trenches and pipes shall be inspected for the presence of wildlife each day prior to the commencement of work.

h. To enable San Joaquin kit foxes and other wildlife to pass through the Project site, any perimeter fencing shall include a 4- to 8-inch opening between the fence mesh and the ground or the fence shall be raised 4 inches above the ground except blunt-nosed leopard lizard exclusion fencing. The bottom of the fence fabric shall be knuckled (wrapped back to form a smooth edge) to protect wildlife.

i. All vertical tubes used in Project construction and chain link fencing poles, shall be temporarily or permanently capped to avoid the entrapment and death of special-status wildlife and birds. All pipes 1.5 inches or greater in diameter stored overnight on a project location must have end caps or other physical barriers that prevent wildlife from entering the pipe.

j. All dead or injured special status wildlife shall be left in place and reported to the United States Fish and Wildlife Service and the California Department of Fish and Wildlife within 48 hours of discovery for rescue or salvage. Discovery of state or federal listed species that are injured or dead shall also be managed consistent with regulatory requirements, including being reported immediately via telephone and within 24 hours in writing, and with a copy to Kern County Planning and Natural Resources.

k. All drilling installations and operations will comply at all times with the applicable federal, State, county, and local law ordinances and regulations.

l. During pre-construction surveys, the qualified biologist shall delineate previously disturbed areas to be used by the applicant to minimize the amount of new disturbance.

m. All concrete and asphalt debris should be removed from the site for recycling or disposal at an authorized, permitted facility.

n. No vehicles or construction equipment shall be parked within a wetland or waterbody/dry wash.

o. Tracked vehicles and other construction equipment must be washed or maintained to be weed-free prior to entering and working within areas of new disturbance.

p. All washing of trucks, paint, equipment, or similar activities should occur in areas where runoff is fully contained for collection and offsite disposal. Wash water may not be discharged from the site and shall be located at least 100 feet from any water body, or sensitive Biological Resources.

q. Locate all extra work areas (such as staging areas and additional spoil storage areas) at least 50 feet away from wetland boundaries or waterbody, except where the adjacent upland consists of cultivated or rotated cropland or other disturbed land.

r. All areas that must be avoided as result of the pre-disturbance surveys, and areas where new disturbance will occur, shall be clearly delineated by fencing or staking and flagging and/or rope or cord.

s. No firearms shall be allowed on any site.

t. No pets shall be allowed on any site.

u. No smoking may occur except in designated areas.

v. If ground disturbance is intended to be temporary and does not occur on cultivated and crop lands, perform topsoil segregation during construction activities to preserve the seed bank for restoration efforts. Store the segregated topsoil separate from the subsoil and restore segregated topsoil to its original location.

MM 4.4-15 Ground disturbance shall be mitigated at a 1.0 to 1.0 ratio (one-acre of new disturbance shall require one-acre of mitigation) except in Tier 1 areas that contain existing disturbance of 70% or greater which shall be mitigated at a 1.0 to 0.5 ratio (one-acre of new disturbance shall require one-half acre of mitigation), for the land included in the Site Plan. This compensatory mitigation requirement does not apply to construction on ground for which compensatory mitigation has already been provided, or on ground that has been previously disturbed (e.g., cleared of vegetation for other oil and gas extraction uses, existing unpaved roads, and existing unvegetated well pads). Ground disturbance activities that are authorized by permits or other written authorizations approved by the United States Fish and Wildlife Service and the California Department of Fish and Wildlife, which include avoidance and compensatory mitigation acreage requirements, may be used to satisfy this County compensatory mitigation ratio. Compensatory mitigation shall be required for the actual acreage of ground disturbance documented during the site plan review and completion process. New disturbance mitigation may be satisfied by one or a combination of the following measures:

a. The recordation of a conservation easement or similar permanent, long-term conservation management agreement in a form acceptable to the County for land within the Project Area on land that has mitigation value. The easement lands may be owned by an Applicant or a third party under contract with an Applicant. Larger land areas may be placed under a conservation easement or similar agreement, and an Applicant may “draw down” the conserved land as needed to satisfy the acreage mitigation requirements for multiple site plan review conformity permits or other authorizations from the County for oil and gas activities.

b. Acquisition of land preservation credits from a mitigation bank located within the Project Area which is owned by the County, on other lands approved by the County, or on lands approved for mitigation or conservation purposes by the United States Fish and Wildlife Service or the California Department of Fish and Wildlife.

c. Removal of legacy oil and gas equipment, inclusive of compliance with applicable legal requirements (e.g., well plugging and abandonment requirements under state or federal regulations), restoration of the surface grade to be consistent with surrounding lands, complete a reseeding effort using native species, and notification of the site owner (if not the Applicant) of the completion of the removal and grading restoration work.

d. Enhancement or restoration of existing habitat on lands already subject to a conservation easement or similar agreement, or which become subject to a conservation easement or similar agreement subsequent to the certification of this Environmental Impact Report, provided that such activities are covered in a permit or authorization, conservation plan, Habitat Conservation Plan, or Natural Community Conservation Plan, approved by the United States Fish and Wildlife Service or the California Department of Fish and Wildlife.

e. Payment of a biological resources mitigation fee for the acquisition and management of mitigation lands, legacy equipment removal, and/or land enhancement already subject to conservation easements or a similar agreements under the terms of any biological resource mitigation program that is adopted by Kern County and approved by the United States Fish and Wildlife Service or the California Department of Fish and Wildlife. The County shall coordinate with the United States Fish and Wildlife Service or the California Department of Fish and Wildlife to identify priority conservation areas and potential conservation partners and funding sources to increase the efficiency and effectiveness of mitigation fee expenditures.

MM 4.4-16 Pre-disturbance surveys shall be conducted by a qualified biologist during the appropriate periods for detecting Sensitive Natural Communities that could occur within the Project Area. The surveys shall be completed consistent with applicable protocols approved by the United States Fish and Wildlife Service and/or the California Department of Fish and Wildlife, including the Protocols for Surveying and Evaluating Impacts to Special Status Native Plant Populations and Natural Communities (California Department of Fish and Wildlife 2009). The qualified person shall map and identify all sensitive natural communities, including riparian communities that occur in or within 100 feet of any new disturbance area. The site plan for the proposed activity shall identify waters, wetlands, resources subject to section 1600 of the CFGC, and other riparian habitats that occur in and within 100 feet of the disturbance area.

MM 4.4- 17 No land disturbance activity in any Sensitive Natural Community that requires a state or federal permit, including state or federally regulated wetlands and waters, shall occur unless the activity is specifically authorized by the issuance of permits or approvals as required by state and federal law. This provision is not intended to restrict survey activities or restrict permit approvals for such disturbance activities. However, no new wells, tanks, sumps or ponds shall be constructed within 50 feet of federal or state waters or wetlands.

MM 4.4-18 In the event that new disturbance would occur at a site within an oak woodland area as defined in Section 1.10.10 of the Kern County General Plan Land Use, Open Space and Conservation Element (10% or greater oak tree cover), the Applicant shall comply with the minimum 30% canopy retention standard in Section 1.10.10 KK (a).

MM 4.4-19 Applicants shall fund through the Site Conformity Review administrative fee, preparation by Kern County of, an annual report describing the Project's ground disturbance acreage, and the acreage of compensatory mitigation lands, in each sub-area. For Covered Activities within areas included in proposed HCPs, the requirements of MM 4.4-1 – 4.4-19 may be superseded by specific requirements imposed by USFWS as part of approval of a federal incidental take permit (e.g., under Section 10 or Section 7 of the Endangered Species Act), or by CDFW as part of approval of a state incidental take permit (e.g., under the Fish and Game Code), provided that USFWS (in the case of a federal incidental take permit) or CDFW (in the case of a state incidental take permit) concludes in writing that such requirements provide equivalent or greater protection than MM 4.4-1 – 4.4-19 (or any subset thereof).

Level of Significance After Mitigation

Project-level biological impacts would be less than significant with mitigation, but cumulative impacts would remain significant and unavoidable based on other foreseeable land disturbance activities in the Project area.

4.18.1.3 Cultural and Paleontological Resources

The 2015 FEIR (Section 4.5, Cultural and Paleontological Resources) included MMs 4.5-1 to 4.5-5 to avoid, minimize, and mitigate the paleontological, historical, and archeological resource impacts of the Project to less than significant levels, but cumulative impacts remained significant based on other foreseeable land disturbance activities in the Project Area and specifically subsurface disturbance. These cultural and paleontological resource mitigation measures were also informed by consultations with expert agencies and tribal representatives. The following cultural and paleontological resources mitigation measures are proposed to be modified to increase clarity and improve implementation of the Ordinance.

Clarified MM 4.5-1

This measure has minor word clarifications to designate the standard for the recovery methods.

MM 4.5 -1 Prior to initiating ground disturbance activities for an activity for which a conformity review is required, the Applicant shall:

a. Provide an archival records search completed by a qualified archaeologist. This shall include an examination of the California Historical Resources Information Files at the Southern San Joaquin Valley Information Center, California State University, Bakersfield, and a search of the Native American Heritage Commission Sacred Lands Files, Sacramento. The Applicant may rely on a previously performed records search for subsequent ground disturbing activities.

b. If an application location has been previously surveyed and no cultural resources have been recorded on it, no further cultural resources studies shall be required.

c. Implement either:

   1. If a site plan includes land that has experienced 100% previous ground-surface disturbance, or is within a section with 300 or more existing oil wells or other agricultural, industrial or urban uses, and the records searches indicate that no cultural or Native American resources are known on it, no further cultural resources studies shall be required. All other application locations shall be subject to intensive (100%) pedestrian ground-surface survey (phase I survey/Class III inventory) by qualified archaeologists. The Applicant may rely on a previously performed ground surface survey for subsequent ground disturbing activities; or

   2. If an application location has not been previously surveyed based on the records search information, an intensive (100%) pedestrian ground-surface survey (Phase I survey/Class III inventory) by qualified archaeologists shall be required.

d. All prehistoric/Native American archaeological sites, whether identified during the records searches or during the intensive survey, shall be demarcated by a qualified archaeologist, fenced by the Applicant, and preserved in place.

e. Historical (Euro-American) archaeological sites that are potentially eligible for listing in the National Register of Historic Places shall be evaluated by a qualified archaeologist and must meet the requirements of the National Historic Preservation Act of 1966 in order to qualify. Qualifying sites, structures and equipment that are identified during the records search or field survey shall be fenced and preserved in open-space, removed and curated, or treated using ~~appropriate~~ data recovery procedures that follow the guidelines of the Secretary of the Interior's Standards for Architectural and Engineering Documentation.

f. Historical (Euro-American) archaeological site types relating to oil and gas activities that have been determined Not Significant/Unique shall require no archaeological study or treatment.

g. All oil and gas industry employees conducting work in the area identified on the Conformity Site Plan shall complete Worker Environmental Awareness Program training including training dedicated to cultural resources protection.

Clarified MM 4.5 -4

This measure has minor word clarifications to clarify that the standards for the recovery and treatment methods are already established and are required to be implemented.

MM 4.5-4 In the event archaeological materials are encountered during the course of ground disturbance or construction, the Project operator/contractor shall cease any ground disturbing activities within 50 feet of the find. The qualified archaeologist shall evaluate the significance of the resources and recommend ~~appropriate~~ treatment measures. Per California Environmental Quality Act Guidelines Section 15126.4(b)(3), Project redesign and preservation in place shall be the preferred means to avoid impacts to significant historical resources. Consistent with California Environmental Quality Act Guidelines Section 15126.4(b)(3)(C), if it is demonstrated that resources cannot be avoided, the qualified archaeologist shall develop additional treatment measures in consultation with the County, which may include data recovery or other ~~appropriate~~ measures. The Planning and ~~Community Development~~ Natural Resources Department shall consult with ~~appropriate~~ Native American representatives in determining ~~appropriate~~ treatment for unearthed cultural resources if the resources are prehistoric or Native American in nature. If after consultation it is determined that ~~deemed~~ ~~appropriate~~, archaeological materials are to be recovered then they ~~during any investigation~~ shall be curated at an accredited curation facility. The qualified archaeologist shall prepare a report documenting evaluation and/or additional treatment of the resource. A copy of the report shall be provided to the Kern County Planning and ~~Community Development~~ Natural Resources Department and to the Southern San Joaquin

Valley Information Center. In the event archaeological materials are encountered, in Tier 2 the surface owner shall be notified immediately.

Mitigation Measures

MM 4.5-1 Prior to initiating ground disturbance activities for an activity for which a conformity review is required, the Applicant shall:

a. Provide an archival records search completed by a qualified archaeologist. This shall include an examination of the California Historical Resources Information Files at the Southern San Joaquin Valley Information Center, California State University, Bakersfield, and a search of the Native American Heritage Commission Sacred Lands Files, Sacramento. The Applicant may rely on a previously performed records search for subsequent ground disturbing activities.

b. If an application location has been previously surveyed and no cultural resources have been recorded on it, no further cultural resources studies shall be required.

c. Implement either:

   1. If a site plan includes land that has experienced 100% previous ground-surface disturbance, or is within a section with 300 or more existing oil wells or other agricultural, industrial or urban uses, and the records searches indicate that no cultural or Native American resources are known on it, no further cultural resources studies shall be required. All other application locations shall be subject to intensive (100%) pedestrian ground-surface survey (phase I survey/Class III inventory) by qualified archaeologists. The Applicant may rely on a previously performed ground surface survey for subsequent ground disturbing activities; or

   2. If an application location has not been previously surveyed based on the records search information, an intensive (100%) pedestrian ground-surface survey (Phase I survey/Class III inventory) by qualified archaeologists shall be required.

d. All prehistoric/Native American archaeological sites, whether identified during the records searches or during the intensive survey, shall be demarcated by a qualified archaeologist, fenced by the Applicant, and preserved in place.

e. Historical (Euro-American) archaeological sites that are potentially eligible for listing in the National Register of Historic Places shall be evaluated by a qualified archaeologist and must meet the requirements of the National Historic Preservation Act of 1966 in order to qualify. Qualifying sites, structures and equipment that are identified during the records search or field survey shall be fenced and preserved in open-space, removed and curated, or treated using data recovery procedures that follow the guidelines of the

Secretary of the Interiors Standards for Architectural and Engineering Documentation.

f. Historical (Euro-American) archaeological site types relating to oil and gas activities that have been determined Not Significant/Unique shall require no archaeological study or treatment.

g. All oil and gas industry employees conducting work in the area identified on the Conformity Site Plan shall complete Worker Environmental Awareness Program training including training dedicated to cultural resources protection.

MM 4.5-2 As part of any Worker Environmental Awareness Program training, all construction personnel shall be trained regarding the recognition of possible buried paleontological resources and protection of paleontological resources during construction, prior to the initiation of construction or ground-disturbing activities. Training shall inform construction personnel of the procedures to be followed upon the discovery of paleontological materials. All personnel shall be instructed that unauthorized collection or disturbance of fossils is unlawful.

MM 4.5-3 All permits for new wells that use Enhanced Oil Recovery or Well Stimulation methods shall pay a mitigation fee of $50 per well shall be paid to the Buena Vista Museum to fund the continued education and curation of paleontological resources and provide educational support regarding the paleontological history of the region.

MM 4.5-4 In the event archaeological materials are encountered during the course of ground disturbance or construction, the Project operator/contractor shall cease any ground disturbing activities within 50 feet of the find. The qualified archaeologist shall evaluate the significance of the resources and recommend treatment measures. Per California Environmental Quality Act Guidelines Section 15126.4(b)(3), Project redesign and preservation in place shall be the preferred means to avoid impacts to significant historical resources. Consistent with California Environmental Quality Act Guidelines Section 15126.4(b)(3)(C), if it is demonstrated that resources cannot be avoided, the qualified archaeologist shall develop additional treatment measures in consultation with the County, which may include data recovery or other measures. The Planning and Natural Resources Department shall consult with Native American representatives in determining treatment for unearthed cultural resources if the resources are prehistoric or Native American in nature. If after consultation it is determined that archaeological materials are to be recovered then they shall be curated at an accredited curation facility. The qualified archaeologist shall prepare a report documenting evaluation and/or additional treatment of the resource. A copy of the report shall be provided to the Kern County Planning and Natural Resources Department and to the Southern San Joaquin Valley Information Center. In the event archaeological materials are encountered, in Tier 2 the surface owner shall be notified immediately.

MM 4.5-5 If human remains are uncovered during Project construction, the Applicant shall immediately halt all work, contact the Kern County Coroner to evaluate the remains, and follow the procedures and protocols set forth in Section 15064.5 (e)(1) of the California Environmental Quality Act Guidelines. The Kern County Planning and Natural Resources Department shall be notified concurrently. If the County Coroner determines that the remains are Native American, the Project proponent shall contact the Native American Heritage Commission, in accordance with Health and Safety Code Section 7050.5, subdivision (c), and Public Resources Code 5097.98 (as amended by Assembly Bill 2641). The Native American Heritage Commission shall designate a Most Likely Descendant for the remains per Public Resources Code 5097.98. Per Public Resources Code 5097.98, the applicant, in coordination with the landowner, shall ensure that the immediate vicinity, according to generally accepted cultural or archaeological standards or practices, where the Native American human remains are located, is not damaged or disturbed by further development activity until the discussion and conference with the Most Likely Descendant has occurred, if applicable, taking into account the possibility of multiple human remains. If the remains are determined to be neither of forensic value to the Coroner, nor of Native American origin, provisions of the California Health and Safety Code (7100 et. seq.) directing identification of the next-of-kin will apply. In the event human remains are uncovered, in Tier 2 the surface owner shall be notified immediately.

Level of Significance After Mitigation

Project levels impacts would be less than significant with mitigation but cumulative impacts would remain significant and unavoidable based on other foreseeable land disturbance activities in the Project area and specifically subsurface disturbance.

4.18.1.4 Geology and Soils

The 2015 FEIR (Section 4.6, Geology and Soils) included MMs 4.6-1 to 4.6-5 to avoid, minimize, and mitigate the impacts of the Project on risks associated with faults, strong seismic ground-shaking, seismic-related ground failure such as liquefaction, landslides, subsidence, and the potential for induced seismic events to less than significant levels. The following geology and soils mitigation measures are proposed to be modified to increase clarity and improve implementation of the Ordinance.

Clarified MM 4.6-3

MM 4.6-3 applies to the drilling of wells on slope of greater than 30%. Kern County has established Chapter 19.88 Hillside Ordinance that strictly prohibits development on slopes over 30% to protect public health, safety and welfare while ensuring development will not induce soil erosion, result in excessive grading, create sewage disposal problems, increase wildfire danger and slope instability or lead to loss of aesthetic value~~. *While* *The ordinance*~~ *Chapter 19.88 Hillside Ordinance* also states that "It is not the intent of this chapter to apply to oil and gas operations," ~~*the standard informs the Kern County standard for this mitigation*~~ as there was no permit required for oil and gas operations when Chapter 19.88 was adopted. The word modifications are needed to specifically delineate the pathway for oil and gas permits to utilize their mineral ownership on land that exceeds 30% slope *and maintain engineering integrity with the protection of public health, safety, and welfare when utilizing a slope of greater than 30%.*

MM 4.6-3 ~~Applicants~~ Operators shall avoid siting ~~not site~~ wells or accessory equipment and facilities on slopes greater than 30%, unless the applicant ~~determines that mineral recovery is infeasible from a different location, and site-specific Professional Engineering certification is submitted concluding that the new equipment will not cause landslides.~~ provides written evidence that the applicant is unable to obtain a mineral lease for a location that is less than 30% slope or professional engineering certification that they cannot slant drill from a location that is less than 30% slope.

If the applicant provides such written evidence, then a site specific geotechnical report certified by a licensed engineering professional shall be submitted in conjunction with any permit detailing the work needed on the slope to construct and operate in full compliance with general engineering practices to ensure slope stability and protections for downslope properties.

The site specific engineering certification and recommendations shall be submitted and reviewed by the Kern County Public Works Department and no permit shall be issued until the Kern County Public Works department provides an engineering approval of the recommendations to protect life and property. All recommendations required by the approved engineering certification from Kern County Public Works shall be implemented. Any requests for deviations from the approved certification will require the processing of a Conditional Use Permit as a discretionary action.

Clarified MM 4.6-5

MM 4.6-5 is clarified for the specific engineering requirements to drill a well in an area with expansive soil.

MM 4.6-5 The Applicant~~s~~ shall avoid building infrastructure on expansive soil, unless the Applicant *provides a professional engineering certification that they cannot slant drill from another location to access the site* ~~*determines that mineral recovery is infeasible from a different location,*~~ and site-specific Professional Engineering certification is submitted concluding that the new equipment will not cause substantial risks to life or property. The site specific professional engineering certification must be submitted, and reviewed by the Kern County Public Works Department and a memo provided that agrees that construction and operation of new equipment will not cause substantial risks to life or property as determined through established engineering standards. All recommendations required by the approved engineering certification from Kern County Public Works shall be implemented.

MM 4.6-1, MM 4.6-2, and **MM 4.6-4** are not recommended for modification from the 2015 FEIR Mitigation Monitoring Program and are included for recommended adoption.

Mitigation Measures

MM 4.6-1 Prior to beginning a ground disturbance activity, the Applicant shall comply with the following regulations (as applicable) and confirm compliance in its Site Plan Conformity Review application documentation:

a. Alquist-Priolo Earthquake Fault Zoning Act.

b. California Building Code.

c. California Geologic Energy Management Division regulations, as identified in the California Code of Regulations, Title 14, Division 2, Chapter 4, including regulations implementing Senate Bill 4 as applicable. If hydraulic fracturing is conducted for any well associated with the Site Plan Conformity Review, the Applicant shall comply with requirements to monitor the California Integrated Seismic Network for indication of an earthquake of magnitude 2.7 or greater for the period of 10 days following the end of hydraulic fracturing. The earthquake search radius shall be consistent with Geologic Energy Management Division Senate Bill 4 regulations. The data will be submitted to Geologic Energy Management Division for an evaluation of the risks and actions consistent with Geologic Energy Management Division Senate Bill 4 regulations. In approving a well stimulation treatment permit that would authorize, within an urban area (i.e., an area with a population over 50,000, as defined by the U.S. Census Bureau), the emplacement of well stimulation fluids into an oil or gas formation that has not been previously been subject to well stimulation activity, and/or into an oil or gas formation for which the Geologic Energy Management Division does not yet possess adequate information about formation fracture geometries, the Geologic Energy Management Division shall impose a permit condition requiring that the applicant conduct ground monitoring to characterize as built fracture geometries prior to, during, and post-hydraulic fracturing. Monitoring shall also be conducted during fracturing treatments by use of applicable microseismic fracture mapping, tilt measurements, tracers, or proppant tagging. Copies of ground monitoring records shall be provided to the County and Geologic Energy Management Division for review and approval within 30 days of well stimulation treatment.

d. Additionally, the Applicant shall:

   1. Avoid placement of structures intended for human occupancy on or within 50 feet of any active faults designated and mapped pursuant to the Alquist-Priolo Earthquake Fault Zoning Act where the fault breaks the surface.

   2. Have a professional geologist prepare a fault rupture hazard evaluation according to guidelines in California Geological Survey Special

Publication 42, 2007 for new developments with structures that are intended for human occupancy.

3. All Class II injection wells shall be authorized, and shall comply with all applicable legal requirements, Underground Injection Control Program Approval permit conditions, and be operated according to the California Code of Regulations Title 14 requirements, as described in the mitigation measures for Hydrology and Water Quality.

4. Ensure that active fault trace placement restrictions are in place for all permanent tanks and storage reservoirs used to store, treat, or transport hazardous materials or materials that are considered pollutants to surface water and groundwater, located in an Earthquake Fault Zone. Ensure that all newly installed pipelines subject to 49 Code of Federal Regulations (CFR) Parts 192 and 195, are engineered and constructed in compliance with the requirements of the pipeline safety regulations, as set forth by the Pipeline Hazardous Materials Safety Administration (PHMSA). All other newly installed pipelines that transport gas or hazardous liquids are to be constructed, tested operated and maintained in accordance with good oilfield practice and applicable standards set forth and approved by the State Oil and Gas Supervisor. Ensure that all new pipelines designated for or water used for fire suppression are engineered and constructed in compliance with the requirements of California Building Code Chapter 9, Fire Protection Systems, and the California Fire Code to address potential fault rupture displacements.

MM 4.6-2 All structures designed for human occupancy shall be designed to withstand substantial ground shaking in accordance with applicable California Building Code seismic design standards and Kern County Building Code.

MM 4.6-3 Operators shall avoid siting wells or accessory equipment and facilities on slopes greater than 30%, provides written evidence that the applicant is unable to obtain a mineral lease for a location that is less than 30% slope or professional engineering certification that they cannot slant drill from a location that is less than 30% slope.

If the applicant provides such written evidence, then a site specific geotechnical report certified by a licensed engineering professional shall be submitted in conjunction with any permit detailing the work needed on the slope to construct and operate in full compliance with general engineering practices to ensure slope stability and protections for downslope properties.

The site specific engineering certification and recommendations shall be submitted and reviewed by the Kern County Public Works Department and no permit shall be issued until the Kern County Public Works department provides an engineering approval of the recommendations to protect life and property. All recommendations required by the approved engineering certification from Kern County Public Works shall be implemented. Any requests for deviations from the approved certification will require the processing of a Conditional Use Permit as a discretionary action.

MM 4.6-4 The Applicant shall confirm compliance with, and shall implement, a Geologic Energy Management Division approved re-pressuring plan as required by Division 3, Chapter 1, Article 5.5 of the Public Resources Code, commencing with Section 3315. In developed areas where subsidence is confirmed or suspected, subsidence monitoring shall be required using Synthetic Aperture Radar studies and/or other methods as approved by the Geologic Energy Management Division to quantify and evaluate the potential effect on the area.

MM 4.6-5 The Applicants shall avoid building infrastructure on expansive soil, unless the Applicant provides a professional engineering certification that they cannot slant drill from another location to access the site and site-specific Professional Engineering certification is submitted concluding that the new equipment will not cause substantial risks to life or property. The site specific professional engineering certification must be submitted, and reviewed by the Kern County Public Works Department and a memo provided that agrees that construction and operation of new equipment will not cause substantial risks to life or property as determined through established engineering standards. All recommendations required by the approved engineering certification from Kern County Public Works shall be implemented.

Level of Significance After Mitigation

Project and cumulative level impacts from project activities would be less than significant with mitigation.

4.18.1.5 Greenhouse Gas Emissions and Global Climate Change

The 2015 FEIR (Section 4.7, Greenhouse Gas Emissions and Global Climate Change) included MMs 4.7-1 to 4.7-4 to avoid, minimize, and mitigate the impacts of the Project on generation of greenhouse gas emissions and contributions to global climate change. With the implementation of the mitigation measures the project-level impacts would be less than significant but the cumulative impacts on global climate change and plans for reduction of emissions would still have significant and unavoidable impacts.

No modifications are proposed to MM 4.7-1 to MM 4.7-4.

Mitigation Measures

MM 4.7.1 An Applicant covered by the Cap-and-Trade Program with permitted stationary sources shall comply with the Cap-and-Trade regulation (especially by surrendering greenhouse gas allowances or offset credits to satisfy their compliance obligation under the Program), and implement Best Performance Standards applicable to greenhouse gas reduction for Components at Light Crude

Oil and Natural Gas Production, Natural Gas Processing Facilities, Petroleum Refineries, Gas Liquids Processing Facilities, and Chemical Plants (San Joaquin Valley Air Pollution Control District 2010), Thermally Enhanced Oil Recovery Wells (San Joaquin Valley Air Pollution Control District 2010a), Steam Generators (San Joaquin Valley Air Pollution Control District 2010b), and Front-line Organic Liquid Storage Tanks (San Joaquin Valley Air Pollution Control District 2011).

MM 4.7.2 Each Applicant covered by the Cap-and-Trade Program shall comply with applicable Cap and Trade regulations, and other applicable greenhouse gas emission control and reduction regulations as these may be adopted or amended over time, to reduce, avoid, mitigate and/or sequester greenhouse gas emissions from Project-related air emissions.

MM 4.7-3 Each Applicant shall implement methods to recover for reuse or destroy methane existing in associated gas and casinghead gas, as follows:

a. Recover all associated gas produced from the reservoir via new wells, regardless of the well type, except for gas produced from wildcat and delineation wells or as a result of start-up, shutdown and maintenance activities (whether planned or unplanned), system failures, and emergencies in accordance with San Joaquin Valley Air Pollution Control District regulations (Rule 4401 and 4409), as this may be amended over time.

b. Compliance with the expected California Air Resources Board methane regulation.

MM 4.7-4 Each Applicant shall offset all greenhouse gas emissions not covered by the Cap-and-Trade program or other mandatory greenhouse gas emission reduction measures through Applicant reductions of greenhouse gas emissions as verified by Kern County, through acquisition of offset credits from the California Air Pollution Control Officers Association Exchange Register or other third party greenhouse gas reductions, with consultation as to the validity of methodology for calculating reductions verified by the San Joaquin Valley Air Pollution Control District and accepted by Kern County, or through inclusion in an Emission Reduction Agreement, to offset Project-related greenhouse gas emissions that are not included in the Cap and Trade program to assure that no net increase in greenhouse gas emissions from the Project.

Level of Significance After Mitigation

Project-level impacts would be less than significant but the cumulative impacts on global climate change and plans for reduction of emissions would still have significant and unavoidable impacts.

4.18.1.6 Hazards and Hazardous Materials/Public Health Risks

The 2015 FEIR (Section 4.8, Hazards and Hazardous Materials) included MMs 4.8-1 to 4. 8-22 to avoid, minimize, and mitigate the impacts of the Project from hazards and hazardous materials.

Hazards associated with seismic conditions are addressed in Section 4.6, Geology and Soils. With the implementation of the mitigation measures, the project-level impacts and cumulative impacts would be less than significant. The following hazards and hazardous materials mitigation measures are proposed to be modified to increase clarity and improve implementation of the Ordinance.

Clarified MM 4.8-2

MM 48-2 is clarified for the specific standards and requirements for implementation.

MM 4.8-2 The Applicant shall arrange for transportation, storage and disposal of all hazardous materials in compliance with the Hazardous Materials Transportation Act. Drivers transporting hazardous materials or wastes should follow the measures recommended by the Federal Motor Carrier Safety Administration for avoiding roll-over accidents which include the following standards for ~~To avoid roll-over accidents~~ ~~involving~~ cargo tank trucks:

a. Avoid sudden movements that may lead to roll-overs.

b. M~~m~~aintain ~~C~~control ~~your~~ of the load in turns and on straight roadways.

c. Identify in advance of transport high risk areas on designated roads.

d. Follow driver mandates for being ~~Remain~~ alert and attentive behind the wheel.

e. Control speed and maintain proper "speed cushions" described by the Federal Motor Carrier Safety Administration.

Clarified MM 4.8-3

MM 4.8-3 is clarified for definitive standards and requirements for implementation.

MM 4.8-3 The Applicant shall implement the following practices based on practices and standards established by the United States Department of Labor Occupational Safety and Health Administration (OSHA) safety standards and as amended or modified by the State of California Department of Industrial Relations, Division of Occupational Safety and Health (DOSH – Cal/OSHA) and the Kern County Fire Department.

a. Construction activities shall be conducted to allow for easy clean-up of spills. Construction crews shall have ~~sufficient~~ *~~the appropriate number of~~* tools, supplies, *and* absorbent and barrier materials *as necessary* to contain and recover spilled materials.

b. Fuels and lubricants shall be stored only at designated staging areas. Fuel and lubricant tanks shall have ~~appropriate~~ secondary spill containment (e.g., curbs). Compliance with laws and regulations is required, including compliance with hazardous materials and hazardous waste storage laws, as applicable.

c. Storage of fuel and lubricants in the staging area shall be at least 100 feet away from the edge of water bodies. Refueling and lubrication of equipment shall be restricted to upland areas at least 100 feet away from stream channels and wetlands.

d. Any fuel truck shall carry an oil spill response kit and spill response equipment at all times.

e. Applicants shall be required to perform all routine equipment maintenance at the well pad or other suitable locations (~~I.~~i.e., maintenance yards), and promptly collect and lawfully dispose of wastes in compliance with existing regulatory requirements.

f. Berms and/or dikes (secondary containment) shall be constructed around the permanent above-ground bulk tanks and the foundations shall be installed with a passive leak detection system, so that potential spill materials shall be contained and collected in specified areas isolated from any water bodies. Tanks shall not be placed in areas subject to periodic flooding or washout. Compliance with laws and regulations is required, including compliance with hazardous materials and hazardous waste storage laws as applicable, including for secondary containment, such as ~~Division of Oil, Gas and Geothermal Resources~~ Geologic Energy Management Division regulation (Title 14, C.C.R. § 1773.1), which requires secondary containment in "an engineered impoundment such as a catch basin, which can include natural topographic features, that is designed to capture fluid released from a production facility."

g. ~~. A~~ ~~sufficient~~ The *~~appropriate~~* amount and supply of sorbent and barrier materials shall be maintained on construction sites consistent with *CalOSHA regulations for* the type and level of construction activities. Sorbent and barrier materials shall also be utilized to contain runoff from contaminated areas *~~consistent with CalOSHA regulations~~*.~~where appropriate~~.

   1. Shovels and drums shall be stored at each well pad or be readily available. If small quantities of soil become contaminated, hand tools ~~such as shovels or other appropriate tools,~~ shall be used to collect the soil and the material shall be stored in storage drums. Large quantities of contaminated soil may be bio-remediated on-site or at a designated remediation facility, subject to government approval, or collected utilizing heavy equipment, and stored in drums or other suitable containers prior to disposal. Should contamination occur adjacent to staging areas as a result of runoff, shovels and/or heavy equipment shall be utilized to collect the contaminated material. Contaminated soil shall be disposed of in accordance with state and federal regulations.

   2. Above-ground tanks, valves and other equipment shall be visually inspected monthly and when the tank is refilled. Inspection records shall be maintained. Applicants shall periodically check tanks for leaks or spills.

3. Drain valves on all tanks shall be locked to prevent accidental or unauthorized discharges from the tank.

4. Equipment maintenance shall be conducted in staging areas or other suitable locations (~~*i.e.,*~~*such as* maintenance shops or yards)~~, to the extent practical~~.

5. The Applicant shall maintain equipment in operating condition to reduce the likelihood of fuel or oil line breaks and leakage. Any vehicles with chronic or continuous leaks shall be removed from the site and repaired before being returned to operation.

~~h. Applicants are encouraged, but not required, to use an alternate to silica sand as a proppant, after Division of Oil Gas and Geothermal Resources has determined that such an alternative does not introduce new hazards.~~

Clarified MM 4.8-4

MM 4.8-4 is clarified for definitive standards and requirements for implementation.

MM 4.8-4 The Applicant shall implement the following measures to prevent, repair, and remediate accidental leaks and spills from oil and gas operations.

a. The Applicant shall identify gas, oil and produced water pipelines to be used for each new or reworked well site in its Site Plan, and shall show the location of any sensitive receptor located within 300 feet of any such pipeline. For any pipeline located within 300 feet of a sensitive receptor, the Applicant shall present evidence that each such pipeline has been integrity tested using pressure testing or other accepted test methods by a qualified professional within a two-year period prior to submittal of the Site Plan, and shall provide a copy of the test result to the County. For all waste gas lines less than or equal to 4 inches in diameter, a Pipeline Management Plan shall be developed and implemented in accordance with California Geologic Energy Management Division ~~of Oil Gas and Geothermal Resources~~ regulations Title 14, Division 2, Chapter 4, Section 1774.2. The Pipeline Management Plan shall include:

1. A listing of information on each pipeline including, but not limited to: i. Pipeline type. ii. Grade. iii. Installation date of pipeline. iv. Design and operational pressure. v. Any leak, repair, inspection and testing history.

2. A description of the testing method and schedule for all pipelines.

b. The Applicant shall notify the Kern County Public Health Services Environmental Health Division, Certified Union Program Agency (CUPA), surface landowner, and sensitive receptors located within 300 feet, of any hazardous materials/waste release immediately upon discovery, and to other applicable agencies as required by other laws. The Applicant shall immediately contain the leak (e.g., by isolating or shutting down the leaking equipment), clean up contaminated media (e.g., soils), and repair the leak prior to recommencing operations. The Applicant shall report the status and progress of the leak repair and remediation work to the County and the CUPA on monthly intervals or predetermined intervals until the repair has been completed. Contaminated media shall be analyzed according to 22 C.C.R. §§ 66261.21-66261.24 for determination of ~~appropriate~~ hazardous waste disposal <u>subject to the</u> Hazardous Waste Determination procedures ~~are~~ provided in 22 C.C.R. §66262.11.

c. As part of the Site Plan, the Applicant shall identify the location and right of way for all pipelines to be used for the transport of oil, gas, and produced water, including pipelines that intersect the main transport line, based on existing data and using commercially available technology, and, based on the results of this analysis, shall identify any sensitive receptors within 300 feet of the pipeline for purposes of complying with Mitigation Measure 4.8-4. Mechanical integrity testing of all such pipeline lengths within 300 feet of a sensitive receptor shall be required pursuant to Mitigation Measure 4.8.4-a.

Clarified MM 4.8-5

Mitigation measure 4.8-5 is clarified for definitive standards and requirements for implementation.

MM 4.8-5 If, during grading or excavation work, the Applicant observes evidence of contamination or if soil contamination is suspected, work near the excavation site shall be terminated, the work area cordoned off and ~~appropriate~~ <u>required</u> health and safety procedures implemented for the location by the contractor's Health and Safety Officer. Samples shall be collected by a trained and qualified individual. Analytical data from suspected contaminated material shall be reviewed by the contractor's Health and Safety Officer. If the sample testing determines that contamination is not present, work may proceed at the site; however, if contamination is detected above regulatory limits, the Kern County Public Health Services Department shall be notified. All actions related to encountering unanticipated hazardous materials at the site shall be documented and submitted to the Kern County Public Health Services Department <u>for legal direction from the regulatory agency</u>

Clarified MM 4.8-6

MM 4.8-6 is clarified for definitive standards and requirements for implementation. <u>*Redundant mitigation for safety sheets has been removed and is fully addressed in MM 4.8-15 and MM.4.8-16.*</u>

MM 4.8-6 The Applicant shall implement measures to prevent the release or accidental spillage of solid waste, garbage, construction debris, sanitary waste, industrial waste, naturally occurring radioactive materials, oil and other petroleum products, and other wastes into water bodies or water sources, including all applicable practices included in the most up-to-date versions of the following documents: Exemption of Oil and Gas Exploration and Production Wastes From Federal Hazardous Waste Regulations (EPA 2002). Equivalent industry standards such as

Environmental Protection for Onshore Oil and Gas Productions and Leases (American Petroleum Institute 2009) and related standards may also be utilized, provided that a professional engineer, certified industrial hygienist or certified safety professional certifies to the County that such ~~alternative~~ standards are as or more protective of human health and the environment, as compared to the standards in the referenced Environmental Protection Agency manual. ~~The determination of when and the extent to which a measure is "practical" is to be made by the Applicant; however, all of the below activities must comply with all applicable legal requirements, including federal and state laws and regulations, County ordinances, and the mitigation measures included in this and the mitigation measures included in this Final EIR.~~ The following are practices and standards that shall be implemented.

a. Classify the various oil and gas exploration and production wastes for ~~proper~~ disposal as described in United States Environmental Protection Agency 2002, and in accordance with applicable California laws and regulations.

b. Size reserve pits ~~properly~~ to avoid overflows.

c. Use closed loop mud systems ~~when practical, particularly~~ with oil-based muds, except in compliance with State Water Resources Board or Regional Water Quality Control Board requirements as provided in Mitigation Measure 4.9-3.

~~*d.*~~ ~~*Review safety data sheets of materials used, and use the less toxic material for the operation. select less toxic alternatives when possible.*~~

~~*e.*~~ *d.* ~~Minimize waste generation, such as by~~ Designi~~ng~~ systems with the ~~*smallest*~~ *necessary* volumes *for drilling mud systems to accomplish drilling operations on the CalGEM Permits*. ~~*possible (e.g., drilling mud systems).*~~

~~f.~~ *e.* Reduce the amount of excess fluids entering reserve and production pits.

~~*g.*~~ *f.* Keep non-exempt wastes out of reserve or production pits.

~~*h.*~~ *g.* Design the drilling pad to contain stormwater and rigwash.

~~*i.*~~ *h.* Recycle and reuse oil-based muds and high density brines, ~~when practical, and~~ when such recycling and reuse complies with hazardous waste laws and recycling laws.

~~*j.*~~ *i.* Perform routine equipment inspections and maintenance to prevent leaks or emissions.

~~*k.*~~ *j.* Reclaim oily debris and tank bottoms ~~when practical, and~~ when such reclamation complies with hazardous waste laws and recycling laws.

~~*l.*~~ *k.* ~~Minimize~~ Store only the volume of materials ~~stored~~ at facilities~~.~~= necessary for permitted work.

~~*m.*~~ *l.* Construct ~~adequate~~ berms around materials and waste storage areas that meet engineering standards to contain spills.

~~n.~~ *m*. Perform routine inspections of materials and waste storage areas to locate damaged or leaking containers.

~~o.~~ *n*. Train personnel in all waste management practices required by the mitigation measures, all legal standards and the permits issued by Kern County, CalGEM and all regulatory agencies. ~~to use sensible waste management practices.~~

Clarified MM 4.8-7

MM 4.8-7 is clarified for definitive standards and requirements for implementation.

MM 4.8-7 ~~Conduct exploration and development activities as described in *Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development The Gold Book* (Bureau of Land Management 2007) or equivalent industry standard such as Environmental Protection for Onshore Oil and Gas Production Operations and Leases (American Petroleum Institute 2009) and related standards.~~ The following specific measures ~~*should*~~ *shall* be ~~undertaken at a~~ implemented at a minimum when conducting exploration and development activities:

a. ~~Sufficient~~ Impervious secondary containment, such as containment dikes, containment walls, and drip pans, ~~should~~ shall be constructed and maintained around all qualifying petroleum facilities, including tank batteries and separation and treating areas consistent with the Environmental Protection Agency's Spill Prevention, Control, and Countermeasures regulation (40 Code of Federal Regulations 112). The containment structure must have sufficient volume to contain, at a minimum, the content of the largest storage tank containing liquid hydrocarbons within the facility/battery and ~~sufficient~~ engineered freeboard to contain precipitation, ~~unless more stringent protective requirements are deemed necessary by the authorized officer.~~ drip pans ~~should~~ shall be routinely checked and cleaned of petroleum or chemical discharges and designed to prevent access by wildlife and livestock, as determined by the qualified biologist.

b. Chemical containers shall ~~should~~ not be stored on bare ground, and shall ~~should~~ be maintained in good condition and shall be placed within secondary containment in case of a spill or high velocity puncture.

c. Containment dikes are not to be constructed with topsoil or coarse~~,~~ ~~*insufficiently impervious*~~ spoil material that is insufficiently impervious to meet requirements. Containment is strongly suggested for produced water tanks. Chemicals shall ~~should~~ be placed within secondary containment and stored so that the containers are not in contact with soil or standing water and product and hazard labels are not exposed to weathering.

d. Maintain a clean well location. Remove trash, junk, and other materials not in current use.

e. In approving a well stimulation treatment permit, the applicant shall include in the spill contingency plan prepared by a qualified professional as required by Section 1722.9 of Title 14 of the California Code of Regulations a protocol for measuring and reporting earthquake and earth consequences that occur during the well stimulation process, for ~~however many~~ the total number of–well stimulation treatments that are proposed to occur simultaneously at any given time. The Spill Contingency Plan shall include requirements for ~~adequate~~ levels of personnel and equipment to respond to ~~based on the extent of the~~ damage that could occur and that ~~may~~ will be necessary to conduct post-earthquake inspection and repair plans to ~~evaluate any~~ address damage that has occurred. The Spill Contingency Plan shall include spill prevention, control and countermeasure plans to address the hazardous substances associated with well stimulation activities. The post-earthquake inspection procedures shall ensure the integrity of the mechanical systems and well integrity of wells used for stimulation or wastewater injection and idle wells that might have become conduits for escaping fluids or gases. The plan shall include procedures describing the necessary steps to be taken after service is disrupted in order to make the facilities secure, operational and safe as soon as possible

Clarified MM 4.8-8

Mitigation measure 4.8-8 is clarified for definitive standards and requirements for implementation.

MM. 4.8-8 Applicants shall use the accepted engineering standards for California oil operations recognized as safe and effective by CalGEM and other state and local regulatory agencies including ~~appropriate~~ American Petroleum Institute Standards, or other recognized sources imposing the same or equivalent standards, for their facility operations and permitting, such as the following:

a. Use cements and well materials in well completions as described in Specifications for Cements and Materials for Well Cementing (American Petroleum Institute 2011).

b. Prior to start-up of all new facilities, verify and· prove the construction, installation, integration, testing, and preparation of systems have been completed as designed following the practices described in Facilities Systems Completion Planning and Execution (American Petroleum Institute 2013a).

c. When the use of centralizers and stop-collars are required during well completion activities, follow the installation and testing requirements described in Recommended Practice for Centralizer Placement and Stop-collar Testing (American Petroleum Institute 2010a).

d. Limit the environmental footprint of oil and gas exploration and production and reduce the incidence of releases of hazardous substances by complying with ~~following~~ the practices described in Environmental Protection for

Onshore Oil and Gas Production Operations and Leases (American Petroleum Institute 2009).

~~e. Minimize~~ e. Eliminate improper disposal by ~~following~~ complying with the practices described in American Petroleum Institute Order No. G00004, Guidelines for Commercial Exploration and Production Waste Management Facilities (American Petroleum Institute 2001) or other ~~recognized~~ legal methods. All disposal must follow applicable laws, regulations, and receiving facilities' permit requirements. ~~These guidelines discuss the relevant regulations and permitting requirements; siting, construction, and technical consideration for various waste disposal options; as well as mitigation options.~~

f. ~~Minimize~~ Limit the environmental footprint of exploration and production activities by complying with ~~following~~ the practices described in Land Drilling Practices for Protection of the Environment (American Petroleum Institute 2010b) or other engineering guidance documents as accepted by CalGEM. ~~recognized sources.~~

g. When pressure testing is required by State or federal law, prior to pressurizing or re-pressurizing petroleum product pipelines, ensure the integrity of pipelines by complying with ~~following~~ the practices described in Recommended Practice for the Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide (American Petroleum Institute 20 13b) or other engineering guidance documents as accepted by CalGEM. ~~recognized sources.~~

h. To ~~minimize~~ prevent releases of hazardous substances during oilfield construction, all pit and sump operations shall be conducted in accordance with State Water Resources Control Board General Orders or ~~appropriate~~ Regional Water Quality Control Board waste discharge requirements or general orders or other legal requirements applicable to oil and gas exploration, extraction, and well stimulation activities.

Clarified MM 4.8-14

MM 4.8-14 is clarified for definitive standards and requirements for implementation.

MM 4. 8-14 The Applicant shall report contamination caused by oil and gas activities, including previously unknown injection wells, of a reportable quantity of hazardous substances, as specified in the Code of Federal Regulations Title 40 and/or the California Code of Regulations Titles 22 and 23, which is discovered during Project construction activities and operations. Notification must be made within 24 hours of discovery to Kern County Public Health Environmental Health Division, Kern County Planning and Natural Resources Department and ~~the appropriate~~ all State and Federal implementing regulatory agencies ~~y~~ that have ~~has~~ responsibility or oversight of the specific contamination conditions and activity. The Applicant shall remediate such contamination outside Tier 1 areas as required by the Kern County Environmental Health Division and the appropriate implementing regulatory agency.

Clarified MM 4.8-15

MM 4.8-15 is clarified for definitive standards and requirements for implementation.

MM 4.8 -15 The Applicant who intends to use acutely hazardous chemicals, including chemicals at or above the specified threshold quantities or a process which involves a Category 1 flammable gas or a flammable liquid with a flashpoint below 100 degrees Fahrenheit (37.8 degrees Celsius) on site in one location, in a quantity of 10,000 pounds (4535.9 kilograms) or more according to 8 California Code of Regulations Section 5189, Appendix A, within 0.25 mile from a school must prepare a Spill Prevention, Control, and Countermeasures Plan which includes details of the following measures as well as those contained in the regulations:

a. Evaluate whether other alternative chemicals that are less hazardous could be used and provide an explanation on why other less hazardous chemicals cannot be used.

b. Include ~~Ensure~~ specific details on ~~that~~ the smallest quantity of necessary acutely hazardous materials that are needed for the specific activity and that will be are stored on site.

c. Notify the occupants of the school buildings when and where acutely hazardous materials would be used.

d. Notify Kern County Fire Department about the details of the use of acutely hazardous materials (e.g., when, where, how much).

e. Ensure that all employees who would contact the acutely hazardous materials are trained on the handling, transport, storage, and disposal of the materials.

f. Ensure that all employees who would contact the acutely hazardous materials are trained and are provided the OSHA mandated ~~proper~~ personal protective equipment.

g. Ensure that all employees who would contact the acutely hazardous materials are trained and have exercised on the Spill Prevention, Control, and Countermeasures Plan that addresses these chemicals.

Clarified MM 4.8-20

MM 4.8-20 is clarified for definitive standards and requirements for implementation.

MM 4.8-20 The Applicant is required to implement the following measures:

a. Comply with Kern County Fire Codes.

b. Maintain firefighting apparatus and supplies required by the Kern County Fire Department.

c. Maintain of a list of all relevant fire-fighting authorities for each work site

d. Have available equipment to extinguish incipient fires and or construction of a fire break, such as: chemical fire extinguishers, shovels, axes, chain saws, etc.

e. Carry water or fire extinguishers and shovels in non-passenger vehicles in the field.

f. Have and maintain ~~an adequate~~ a supply of fire extinguishers for welding, grinding, and brushing crews in compliance with Cal OSHA regulations.

g. Use available resources to protect individual safety and to contain any fire that occurs and notify local emergency response personnel.

h. Remove any flammable wastes generated during oil and gas activities regularly.

i. Store all flammable materials used in oil and gas activities away from ignition sources and in approved containers.

j. Allow smoking only in designated smoking areas.

k. Prohibit smoking where flammable products are present and when the fire hazard is high. Train personnel regarding potential fire hazards and their prevention.

l. All internal combustion engines, stationary and mobile, shall be equipped with spark arresters. Spark arresters shall be in good working order.

m. Light trucks and cars with factory-installed (type) mufflers shall be used only on roads where the roadway is cleared of vegetation. Said vehicle types shall maintain their factory-installed (type) muffler in good condition.

n. Fire rules shall be posted on the Project bulletin board at the contractor's field office and areas visible to employees.

o. Equipment parking areas and small stationary engine sites shall be cleared of all extraneous flammable materials.

p. Personnel shall be trained in the practices of the Fire Safety Plan relevant to their duties. Construction and maintenance personnel shall be trained and equipped to extinguish small fires in order to prevent them from growing into more serious threats

Clarified MM 4.8-22

MM 4.8-22 is clarified for definitive standards and requirements for implementation.

MM 4.8-22 Applicants shall ensure that trash is stored in closed containers and removed from the site at regular intervals. Open containers shall be inverted and construction ditches shall not be allowed to accumulate water. Construction and maintenance operations shall not generate standing water. Naturally occurring depressions, drainages, or pools at the site shall not be drained or filled without a permit from any regulatory agency having jurisdiction over the resource location. ~~consulting~~

~~with the appropriate resource agency (Kern County, United States Army Corps of Engineers, United States Fish and Wildlife Service, California Department of Fish and Wildlife) as applicable, and obtaining the appropriate permits~~

Mitigation Measures

MM 4.8-1 The Applicant shall provide a comprehensive Worker Environmental Awareness Program to the County with its first Site Plan Conformity Review permit application in each calendar year. The program shall include all training requirements identified in Applicant Best Management Practices and mitigation measures, and include training for all field personnel (including Applicant employees, agents and contractors). The Worker Environmental Awareness Program shall include protocols and training for responding to and handling of hazardous materials and hazardous waste management, and emergency preparedness, release reporting, and response requirements. In Tier 2, the Worker Environmental Awareness Program shall be provided to the surface owner at the time of the application pathway process so the surface owner may educate employees as well.

MM 4.8-2 The Applicant shall arrange for transportation, storage and disposal of all hazardous materials in compliance with the Hazardous Materials Transportation Act. Drivers transporting hazardous materials or wastes should follow the measures recommended by the Federal Motor Carrier Safety Administration for avoiding roll-over accidents which include the following standards for cargo tank trucks:

a. Avoid sudden movements that may lead to roll-overs.

b. Maintain control of the load in turns and on straight roadways.

c. Identify in advance of transport high risk areas on designated roads.

d. Follow driver mandates for being alert and attentive behind the wheel.

e. Control speed and maintain proper "speed cushions" described by the Federal Motor Carrier Safety Administration.

MM 4.8-3 The Applicant shall implement the following practices based on practices and standards established by the United States Department of Labor Occupational Safety and Health Administration (OSHA) safety standards and as amended or modified by the State of California Department of Industrial Relations, Division of Occupational Safety and Health (DOSH – Cal/OSHA) and the Kern County Fire Department.

a. Construction activities shall be conducted to allow for easy clean-up of spills. Construction crews shall have tools, supplies, absorbent and barrier materials as necessary to contain and recover spilled materials.

b. Fuels and lubricants shall be stored only at designated staging areas. Fuel and lubricant tanks shall have secondary spill containment (e.g., curbs).

Compliance with laws and regulations is required, including compliance with hazardous materials and hazardous waste storage laws, as applicable.

c. Storage of fuel and lubricants in the staging area shall be at least 100 feet away from the edge of water bodies. Refueling and lubrication of equipment shall be restricted to upland areas at least 100 feet away from stream channels and wetlands.

d. Any fuel truck shall carry an oil spill response kit and spill response equipment at all times.

e. Applicants shall be required to perform all routine equipment maintenance at the well pad or other suitable locations (i.e., maintenance yards), and promptly collect and lawfully dispose of wastes in compliance with existing regulatory requirements.

f. Berms and/or dikes (secondary containment) shall be constructed around the permanent above-ground bulk tanks and the foundations shall be installed with a passive leak detection system, so that potential spill materials shall be contained and collected in specified areas isolated from any water bodies. Tanks shall not be placed in areas subject to periodic flooding or washout. Compliance with laws and regulations is required, including compliance with hazardous materials and hazardous waste storage laws as applicable, including for secondary containment, such as Geologic Energy Management Division regulation (Title 14, C.C.R. § 1773.1), which requires secondary containment in "an engineered impoundment such as a catch basin, which can include natural topographic features, that is designed to capture fluid released from a production facility."

g. The amount and supply of sorbent and barrier materials shall be maintained on construction sites consistent with CalOSHA regulations for the type and level of construction activities. Sorbent and barrier materials shall also be utilized to contain runoff from contaminated areas.

   1. Shovels and drums shall be stored at each well pad or be readily available. If small quantities of soil become contaminated, hand tools shall be used to collect the soil and the material shall be stored in storage drums. Large quantities of contaminated soil may be bio-remediated on-site or at a designated remediation facility, subject to government approval, or collected utilizing heavy equipment, and stored in drums or other suitable containers prior to disposal. Should contamination occur adjacent to staging areas as a result of runoff, shovels and/or heavy equipment shall be utilized to collect the contaminated material. Contaminated soil shall be disposed of in accordance with state and federal regulations.

   2. Above-ground tanks, valves and other equipment shall be visually inspected monthly and when the tank is refilled. Inspection records shall be maintained. Applicants shall periodically check tanks for leaks or spills.

3. Drain valves on all tanks shall be locked to prevent accidental or unauthorized discharges from the tank.
4. Equipment maintenance shall be conducted in staging areas or other suitable locations such as maintenance shops or yards).
5. The Applicant shall maintain equipment in operating condition to reduce the likelihood of fuel or oil line breaks and leakage. Any vehicles with chronic or continuous leaks shall be removed from the site and repaired before being returned to operation.

MM 4.8-4 The Applicant shall implement the following measures to prevent, repair, and remediate accidental leaks and spills from oil and gas operations.

a. The Applicant shall identify gas, oil and produced water pipelines to be used for each new or reworked well site in its Site Plan, and shall show the location of any sensitive receptor located within 300 feet of any such pipeline. For any pipeline located within 300 feet of a sensitive receptor, the Applicant shall present evidence that each such pipeline has been integrity tested using pressure testing or other accepted test methods by a qualified professional within a two-year period prior to submittal of the Site Plan, and shall provide a copy of the test result to the County. For all waste gas lines less than or equal to 4 inches in diameter, a Pipeline Management Plan shall be developed and implemented in accordance with California Geologic Energy Management Division regulations Title 14, Division 2, Chapter 4, Section 1774.2. The Pipeline Management Plan shall include:

   1. A listing of information on each pipeline including, but not limited to: i. Pipeline type. ii. Grade. iii. Installation date of pipeline. iv. Design and operational pressure. v. Any leak, repair, inspection and testing history.
   2. A description of the testing method and schedule for all pipelines.

b. The Applicant shall notify the Kern County Public Health Services Environmental Health Division, Certified Union Program Agency (CUPA), surface landowner, and sensitive receptors located within 300 feet, of any hazardous materials/waste release immediately upon discovery, and to other applicable agencies as required by other laws. The Applicant shall immediately contain the leak (e.g., by isolating or shutting down the leaking equipment), clean up contaminated media (e.g., soils), and repair the leak prior to recommencing operations. The Applicant shall report the status and progress of the leak repair and remediation work to the County and the CUPA on monthly intervals or predetermined intervals until the repair has been completed. Contaminated media shall be analyzed according to 22 C.C.R. §§ 66261.21-66261.24 for determination of hazardous waste disposal subject to the Hazardous Waste Determination procedures provided in 22 C.C.R. §66262.11.

c. As part of the Site Plan, the Applicant shall identify the location and right of way for all pipelines to be used for the transport of oil, gas, and produced water, including pipelines that intersect the main transport line, based on existing data and using commercially available technology, and, based on the results of this analysis, shall identify any sensitive receptors within 300 feet of the pipeline for purposes of complying with Mitigation Measure 4.8-4. Mechanical integrity testing of all such pipeline lengths within 300 feet of a sensitive receptor shall be required pursuant to Mitigation Measure 4.8.4-a.

MM 4.8-5 If, during grading or excavation work, the Applicant observes evidence of contamination or if soil contamination is suspected, work near the excavation site shall be terminated, the work area cordoned off and required health and safety procedures implemented for the location by the contractor's Health and Safety Officer. Samples shall be collected by a trained and qualified individual. Analytical data from suspected contaminated material shall be reviewed by the contractor's Health and Safety Officer. If the sample testing determines that contamination is not present, work may proceed at the site; however, if contamination is detected above regulatory limits, the Kern County Public Health Services Department shall be notified. All actions related to encountering unanticipated hazardous materials at the site shall be documented and submitted to the Kern County Public Health Services Department for legal direction from the regulatory agency.

MM 4.8-6 The Applicant shall implement measures to prevent the release or accidental spillage of solid waste, garbage, construction debris, sanitary waste, industrial waste, naturally occurring radioactive materials, oil and other petroleum products, and other wastes into water bodies or water sources, including all applicable practices included in the most up-to-date versions of the following documents: Exemption of Oil and Gas Exploration and Production Wastes From Federal Hazardous Waste Regulations (EPA 2002). Equivalent industry standards such as Environmental Protection for Onshore Oil and Gas Productions and Leases (American Petroleum Institute 2009) and related standards may also be utilized, provided that a professional engineer, certified industrial hygienist or certified safety professional certifies to the County that such standards are as or more protective of human health and the environment, as compared to the standards in the referenced Environmental Protection Agency manual. The following are practices and standards that shall be implemented.

a. Classify the various oil and gas exploration and production wastes for disposal as described in United States Environmental Protection Agency 2002, and in accordance with applicable California laws and regulations.

b. Size reserve pits to avoid overflows.

c. Use closed loop mud systems with oil-based muds except in compliance with State Water Resources Board or Regional Water Quality Control Board requirements as provided in Mitigation Measure 4.9-3.

d. Design systems with the necessary volumes for drilling mud system to accomplish drilling operations on the CalGEM Permits.

e. Reduce the amount of excess fluids entering reserve and production pits.

f. Keep non-exempt wastes out of reserve or production pits.

g. Design the drilling pad to contain stormwater and rigwash.

h. Recycle and reuse oil-based muds and high density brines, when such recycling and reuse complies with hazardous waste laws and recycling laws.

i. Perform routine equipment inspections and maintenance to prevent leaks or emissions.

j. Reclaim oily debris and tank bottoms when such reclamation complies with hazardous waste laws and recycling laws.

k. Store only the volume of materials at facilities necessary for permitted work.

l. Construct berms around materials and waste storage areas that meet engineering standards to contain spills.

m. Perform routine inspections of materials and waste storage areas to locate damaged or leaking containers.

n. Train personnel in all waste management practices required by the mitigation measures, all legal standards and the permits issued by Kern County, CalGEM and all regulatory agencies.

MM 4.8-7 The following specific measures shall be implemented at a minimum when conducting exploration and development activities:

a. Impervious secondary containment, such as containment dikes, containment walls, and drip pans shall be constructed and maintained around all qualifying petroleum facilities, including tank batteries and separation and treating areas consistent with the Environmental Protection Agency's Spill Prevention, Control, and Countermeasures regulation (40 Code of Federal Regulations 112). The containment structure must have sufficient volume to contain, at a minimum, the content of the largest storage tank containing liquid hydrocarbons within the facility/battery and engineered freeboard to contain precipitation. Drip pans shall be routinely checked and cleaned of petroleum or chemical discharges and designed to prevent access by wildlife and livestock.as determined by the qualified biologist.

b. Chemical containers shall not be stored on bare ground, and shall be maintained in good condition and shall be placed within secondary containment in case of a spill or high velocity puncture.

c. Containment dikes are not to be constructed with topsoil or coarse, spoil material that is insufficiently impervious to meet requirements. Containment is strongly suggested for produced water tanks. Chemicals shall be placed within secondary containment and stored so that the containers are not in contact with soil or standing water and product and hazard labels are not exposed to weathering.

d. Maintain a clean well location. Remove trash, junk, and other materials not in current use.

e. In approving a well stimulation treatment permit, the applicant shall include in the spill contingency plan prepared by a qualified professional as required by Section 1722.9 of Title 14 of the California Code of Regulations a protocol for measuring and reporting earthquake and earth consequences that occur during the well stimulation process, for the total number of well stimulation treatments are proposed to occur simultaneously at any given time. The Spill Contingency Plan shall include requirements for levels of personnel and equipment to respond to damage that could occur and that will be necessary to conduct post-earthquake inspection and repair plans to address any damage that has occurred. The Spill Contingency Plan shall include spill prevention, control and countermeasure plans to address the hazardous substances associated with well stimulation activities. The post-earthquake inspection procedures shall ensure the integrity of the mechanical systems and well integrity of wells used for stimulation or wastewater injection and idle wells that might have become conduits for escaping fluids or gases. The plan shall include procedures describing the necessary steps to be taken after service is disrupted in order to make the facilities secure, operational and safe as soon as possible

MM. 4.8-8 Applicants shall use the accepted engineering standards for California oil operations recognized as safe and effective by CalGEM and other state and local regulatory agencies including American Petroleum Institute Standards, or other recognized sources imposing the same or equivalent standards, for their facility, operations and permitting such as the following:

a. Use cements and well materials in well completions as described in Specifications for Cements and Materials for Well Cementing (American Petroleum Institute 2011).

b. Prior to start-up of all new facilities, verify and· prove the construction, installation, integration, testing, and preparation of systems have been completed as designed following the practices described in Facilities Systems Completion Planning and Execution (American Petroleum Institute 2013a).

c. When the use of centralizers and stop-collars are required during well completion activities, follow the installation and testing requirements described in Recommended Practice for Centralizer Placement and Stop-collar Testing (American Petroleum Institute 2010a).

d. Limit the environmental footprint of oil and gas exploration and production and reduce the incidence of releases of hazardous substances by complying with the practices described in Environmental Protection for Onshore Oil and Gas Production Operations and Leases (American Petroleum Institute 2009).

e. Eliminate improper disposal by complying with the practices described in American Petroleum Institute Order No. G00004, Guidelines for Commercial Exploration and Production Waste Management Facilities (American Petroleum Institute 2001) or other legal methods. All disposal must follow applicable laws, regulations, and receiving facilities permit requirements.

f. Limit the environmental footprint of exploration and production activities by complying with the practices described in Land Drilling Practices for Protection of the Environment (American Petroleum Institute 2010b) or other engineering guidance documents as accepted by CalGEM.

g. When pressure testing is required by State or federal law, prior to pressurizing or re-pressurizing petroleum product pipelines, ensure the integrity of pipelines by complying with the practices described in Recommended Practice for the Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide (American Petroleum Institute 20 13b) or other engineering guidance documents as accepted by CalGEM.

h. To prevent releases of hazardous substances during oilfield construction, all pit and sump operations shall be conducted in accordance with State Water Resources Control Board General Orders or Regional Water Quality Control Board waste discharge requirements or general orders or other legal requirements applicable to oil and gas exploration, extraction and well stimulation activities.

MM 4.8-9 For all operations subject to the Oil and Gas Conformity Review, the Applicant shall comply with the pipeline management plan, including inspection and maintenance requirements, as administered by the Geologic Energy Management Division pursuant to 14 California Code of Regulations 1774.

MM 4.8-10 The Applicant shall incorporate annual maintenance checks for leaks and corrosion that cause releases into current operations, maintenance, and inspection schedules as provided by the Geologic Energy Management Division pursuant to 14 California Code of Regulations Sections 1774.1 and 1774.2, the Applicant shall visually inspect all above-ground pipelines for leaks and corrosion at least once per year, comply with the pipeline testing requirements included therein, shall maintain records of such inspections and testing; and shall make inspection and testing records available to the County for review upon request.

MM 4.8-11 As part of the Hazardous Materials Business Plan and the spill prevention, control, and Countermeasures Plan, the Applicant shall require annual worker training requirements to: increase awareness of the most common types of failures and methods to avoid mistakes, shall maintain records of employee training, and shall make such records available to the County for review upon request.

MM 4.8-12 An Applicant who plans to perform cyclic steam injection activities above reservoir fracture pressures shall conduct such activities in accordance with the requirements set forth in the Geologic Energy Management Division site-specific Project Approval Letter for the injection project. The following requirements from a Project Approval Letter for an injection project are examples of the types of conditions that would be triggered if a surface expression were to occur, though such conditions may be modified by the Geologic Energy Management Division to reflect site-specific conditions and changing regulatory requirements.

a. Cease cyclic steaming operations in accordance with the site-specific Project Approval Letter. Streaming can resume following the Geologic Energy Management Division specifications outlined in the Project Approval Letter.

b. All new or reactivated surface expressions that discharge oil in a reportable quantity shall be reported as an oil spill to the California Emergency Management Agency at (800) 852-7550.

c. Any measures to address surface expressions from the well and associated Project shall be reviewed by the Geologic Energy Management Division prior to initiating.

d. Immediately control any water, steam, or oil flowing from a surface expression and contained. All discharged material shall be removed and disposed of in a manner approved by all state and local agencies.

e. Cordon off and clearly mark all surface expressions to prevent inadvertent access.

f. Conduct air sampling of any emissions associated to a recent surface expression in accordance to the local air board requirements to ensure a health hazard condition does not exist.

g. Report immediately to the Geologic Energy Management Division all surface expressions within 300 feet of the Project site. If the surface expression continues to flow after five days, all wells within a 300-foot radius shall cease steaming until the surface expression ceases to flow. If the surface expression continues to flow, the damage will be evaluated at the Supervisor's discretion, as assigned by Section 3106 of the Public Resources Code and existing laws and regulations.

MM 4.8-13 The Applicant shall comply with the Geologic Energy Management Division requirements for assuring safe drilling and drill casing practices, well design, construction and well management requirements, blowout requirements, and all other provisions of 14 California Code of Regulations 1744 and other applicable Geologic Energy Management Division_regulations. The Applicant shall also reduce the incidence of well control loss by following the practices described in Recommended Practice for Well Control Operations (American Petroleum Institute 2012).

MM 4. 8-14 The Applicant shall report contamination caused by oil and gas activities, including previously unknown injection wells, of a reportable quantity of hazardous substances, as specified in the Code of Federal Regulations Title 40 and/or the California Code of Regulations Titles 22 and 23, which is discovered during Project construction activities and operations. Notification must be made within 24 hours of discovery to Kern County Public Health Environmental Health Division, Kern County Planning and Natural Resources Department and all State and Federal implementing regulatory agencies that have responsibility or oversight of the specific contamination conditions and activity. The Applicant shall remediate such contamination outside Tier 1 areas as required by the Kern County Environmental Health Division and the appropriate implementing regulatory agency.

MM 4.8-15 The Applicant who intends to use acutely hazardous chemicals, including chemicals at or above the specified threshold quantities or a process which involves a Category 1 flammable gas or a flammable liquid with a flashpoint below 100 degrees Fahrenheit (37.8 degrees Celsius) on site in one location, in a quantity of 10,000 pounds (4535.9 kilograms) or more according to 8 California Code of Regulations Section 5189, Appendix A, within 0.25 mile from a school must prepare a Spill Prevention, Control, and Countermeasures Plan which includes details of the following measures as well as those contained in the regulations :

a. Evaluate whether other alternative chemicals that are less hazardous could be used and provide an explanation on why other less hazardous chemicals cannot be used.

b. Include specific details on the smallest quantity of necessary acutely hazardous materials that are needed for the specific activity and that will be stored on site.

c. Notify the occupants of the school buildings when and where acutely hazardous materials would be used.

d. Notify Kern County Fire Department about the details of the use of acutely hazardous materials (e.g., when, where, how much).

e. Ensure that all employees who would contact the acutely hazardous materials are trained on the handling, transport, storage, and disposal of the materials.

f. Ensure that all employees who would contact the acutely hazardous materials are trained and are provided the OSHA mandated personal protective equipment.

g. Ensure that all employees who would contact the acutely hazardous materials are trained and have exercised on the Spill Prevention, Control, and Countermeasures Plan that addresses these chemicals.

MM 4.8-16 The applicant shall not use any well stimulation fluid unless the applicant presents one of the following:

1. Safety Data Sheet that accurately describes the physical and chemical properties of the well stimulation fluid; or
2. Safety Data Sheets that accurately describe the physical and chemical properties of all chemical compounds in the well stimulation fluid; or
3. Toxicological report prepared by a qualified laboratory and/or the fluid vendor confirming the environmental profile of the well stimulation fluid is known; or
4. Results of an aquatic bioassay by a qualified laboratory confirming the environmental profile of the well stimulation fluid is known.

For purposes of this mitigation measure, the term "environmental profile" means the physical and chemical properties of a compound that determine its risk to human health and the environment. This mitigation measure shall be superseded by any list of approved well stimulation treatment fluids, chemicals or additives published by the State of California or by any applicable State of California regulation pertaining to chemical use in well stimulation treatment.

MM 4.8-17 The Applicant shall determine whether any proposed construction or alteration meets requirements for notification of the Federal Aviation Administration. If a proposed construction or alteration is found to require notification, the Applicant shall notify the Federal Aviation Administration and request that the Federal Aviation Administration issue a Determination of No Hazard to Air Navigation. If the Federal Aviation Administration determines that the construction or alteration would result in a potential hazard to air navigation, the Applicant would be required to work with the Federal Aviation Administration to resolve any adverse effects or airport operations. The Applicant shall notify the Federal Aviation Administration and the nearest Airport, by completing and submitting Federal Aviation Administration Form 7460-1 if oil and gas related exploration, production, or associated development activities are planned that meet one or more of the following criteria:

a. Any construction or alteration exceeding 200 feet above ground level.

b. Any construction or alteration within 20,000 feet of all public use airports except Poso-kern Airport which exceeds a 100:1 surface from any point on the runway.

c. Any construction or alteration within 10,000 feet of the Poso-Kern Airport which exceeds a 50:1 surface from any point on the runway.

d. Any construction or alteration within 5,000 feet of a public use heliport which exceeds a 25:1 surface.

e. When requested by the Federal Aviation Administration.

f. Any construction or alteration located on a public use airport or heliport regardless of height or location.

MM 4.8-18 The Applicant shall determine the distance from the proposed operation to the nearest boundary of the Joint Service Restricted R-2508 Complex, using a map of this Complex provided by the County. The Applicant shall notify the Joint Service Restricted R2508 Complex representative identified by the County if oil and gas related exploration, production, or associated development activities are planned that meet one or more of the following criteria:

a. Any structure within 75 miles of the R-2508 Complex that is greater than 50 feet tall.

b. Any project within 50 miles of the R-2508 Complex that emit radio and communication frequencies.

c. Any project that would create environmental impacts such as visibility or elevated obstructions within 25 miles of the R-2508 Complex.

MM 4.8-19 All oil and gas related development activities shall review the Kern County Airport Land Use Compatibility Plan for compliance with all applicable policies.

MM 4.8-20 The Applicant is required to implement the following measures:

a. Comply with Kern County Fire Codes.

b. Maintain firefighting apparatus and supplies required by the Kern County Fire Department.

c. Maintain of a list of all relevant fire-fighting authorities for each work site

d. Have available equipment to extinguish incipient fires and or construction of a fire break, such as: chemical fire extinguishers, shovels, axes, chain saws, etc.

e. Carry water or fire extinguishers and shovels in non-passenger vehicles in the field.

f. Have and maintain a supply of fire extinguishers for welding, grinding, and brushing crews in compliance with CalOSHA regulations.

g. Use available resources to protect individual safety and to contain any fire that occurs and notify local emergency response personnel.

h. Remove any flammable wastes generated during oil and gas activities regularly.

i. Store all flammable materials used in oil and gas activities away from ignition sources and in approved containers.

j. Allow smoking only in designated smoking areas.

k. Prohibit smoking where flammable products are present and when the fire hazard is high. Train personnel regarding potential fire hazards and their prevention.

l. All internal combustion engines, stationary and mobile, shall be equipped with spark arresters. Spark arresters shall be in good working order.

m. Light trucks and cars with factory-installed (type) mufflers shall be used only on roads where the roadway is cleared of vegetation. Said vehicle types shall maintain their factory-installed (type) muffler in good condition.

n. Fire rules shall be posted on the Project bulletin board at the contractor's field office and areas visible to employees.

o. Equipment parking areas and small stationary engine sites shall be cleared of all extraneous flammable materials.

p. Personnel shall be trained in the practices of the Fire Safety Plan relevant to their duties. Construction and maintenance personnel shall be trained and equipped to extinguish small fires in order to prevent them from growing into more serious threats.

MM 4.8-21 The Applicant should restrict the use of chainsaws, chippers, vegetation masticators, grinders, tractors, torches, and explosives at its locations, and ensure the sites where this equipment is used are equipped with portable or fixed fire extinguishers and/or a water tank, with hoses, fire rakes, and other tools to extinguish and or control incipient stage fires. The Worker Environmental Awareness Program shall include fire prevention and response training for workers using these tools.

MM 4.8-22 Applicants shall ensure that trash is stored in closed containers and removed from the site at regular intervals. Open containers shall be inverted and construction ditches shall not be allowed to accumulate water. Construction and maintenance operations shall not generate standing water. Naturally occurring depressions, drainages, or pools at the site shall not be drained or filled without a permit from any regulatory agency having jurisdiction over the resource location.

Level of Significance

With the implementation of the mitigation measures the project-level impacts and cumulative impacts would be less than significant

4.18. 1.7 Land Use and Planning

The 2015 FEIR (Section 4.10, Land Use and Planning) required no mitigation measures, and no additions are recommended. Both the project and cumulative level impacts were found to be less than significant.

Mitigation Measures

No mitigation is required

Level of Significance

Project and cumulative impacts are less than significant.

4.18.1.8 Mineral Resources

The 2015 FEIR (Section 4.11, Mineral Resources) required no mitigation measures, and no additions are recommended. Both the project and cumulative level impacts were found to be less than significant.

Mitigation Measures

No mitigation is required

Level of Significance

Project and cumulative impacts are less than significant.

4.18.1.9 Population and Housing

The 2015 FEIR (Section 4.13, Population and Housing) required no mitigation measures, and no additions are recommended. Both the project and cumulative level impacts were found to be less than significant.

Mitigation Measures

No mitigation is required

Level of Significance

Project and cumulative impacts are less than significant.

4.18.1.10 Public Services

The 2015 FEIR (Section 4.14, Public Services) included MM 4.14-1 and MM 4.14-2 as requirements to mitigate the impacts on law enforcement and fire services due to increased oil and gas activities. Both the project- and cumulative-level impacts were found to be less than significant. The following modification to mitigation is required to reflect the results of permitting over the last four years.

The mitigation measure will be deleted as fully implemented.

MM 4.14 -1 ~~Applicant shall contribute to funding the acquisition of a Combination Walk-in/Non-Walk-in Industrial Firefighting vehicle capable of responding with a minimum of five firefighters with the tools and equipment necessary for industrial firefighting and rescue. Each Applicant shall pay $150 per well on each Oil and Gas Conformity Review permit until the total cost of the vehicle purchase is reached, not to exceed $850,000, to be paid through mitigation fees on Oil and Gas Conformity Review permits. Subsequent Applicants shall not be subject to this mitigation measure.~~

No changes are required for MM 4.14-2, with the exception of renumbering.

Mitigation Measure

MM 4. 14-1 Applicant shall provide funding in the amount of $ 425 per Oil and Gas Conformity Review permit issued for the Sheriff's Rural Crime Unit. Funding shall be used for one Sergeant, two Senior Deputies (investigators), three Deputies, One Support Technician (clerical) and helicopter usage, based on the amount of funding provided by this permit mitigation fee. The Sheriff's department shall annually report on the expenditure of funds for the Rural Crimes Unit, including incident reports and response times. If other sources of funding for the Rural Crimes Unit are secures, then the mitigation amount shall be adjusted to pay only the gap between actual costs and funding provided from other sources.

Level of Significance

Project and cumulative impacts are less than significant.

4.18.1.11 Recreation

The 2015 FEIR (Section 4.15, Recreation) required no mitigation measures, and no additions are recommended. Both the project- and cumulative-level impacts were found to be less than significant.

Mitigation Measures

No mitigation is required

Level of Significance

Project and cumulative impacts are less than significant.

4.18.1.12 Transportation and Traffic

The 2015 FEIR (Section 16, Transportation and Traffic) included MMs 4.16-1 and 4.16 -2 to avoid, minimize, and mitigate the impacts of the Project on transportation corridors and from traffic conflicts and congestion. Both the project- and cumulative-level impacts were found to be less than significant. The following modification to mitigation are minor wording clarifications for clear directions to applicants on permit compliance.

Clarified MM 4.16 -2

This mitigation measure requires consultation and a determination by Kern County Public Works, based on traffic engineering standards when the level and location of traffic requires a traffic control plan for the oil operations. Minor word clarifications ensure clear direction.

MM 4.16 -2 Applicants who are using an arterial or collector, or Caltrans route, for access to a construction site, shall consult with the Kern County Public Works Department ~~to determine if a Construction Traffic Control Plan is required based on the timing and volume of larger vehicle rigs and the volume of traffic to address public safety and congestion management~~. The Kern County Public Works Department based on established engineering safety standards and current traffic generation data will determine if a Construction Traffic Control Plan is required based on the timing and volume of larger vehicle rigs and the volume of traffic to address public safety and congestion management. If a Plan is required, the Applicant shall prepare and submit a Construction Traffic Control Plan to the Kern County Public Works Department and to the California Department of Transportation (District 9 office) for approval. The Construction Traffic Control Plan must be prepared in accordance with both the California Department of Transportation Manual on Uniform Traffic Control Devices and Work Area Traffic Control Handbook and shall include, but not be limited to, the following issues

a. Timing of deliveries or heavy equipment and building materials

b. Placing temporary signage, lighting and traffic control devices as necessary to indicate the presence of heavy vehicles and construction traffic

c. ~~Determining the need~~ ~~s~~Specifying ~~for~~ construction work hours and arrival/departure times outside peak traffic periods.

d. Ensuring access for emergency vehicles to the project site.

e. Any temporary closure of travel lanes or disruptions to street segments and intersections during well development

f. Maintaining access to adjacent property.

Mitigation Measures

MM 4.16-1 The Applicant shall pay a road maintenance mitigation fee of $1,500 per permit for new wells to pay for roadway maintenance and related improvements to address wear and tear on roads caused by oil and gas industry traffic. The Kern County Public Works Department shall annually report on the expenditure of funds from the Oil and Gas Roadway Maintenance Fee. Expenditures from the fund shall be as determined by the Roads Commissioner, using as a reference the list of roadways identified in the Environmental Impact Report as being used for traffic by the oil and gas industry. If Kern County secures funding from a sales tax dedicated to transportation funding, then the amount of the traffic mitigation fee shall be re-evaluated at the time the County becomes a self-help county. The first 100 permits issued in a calendar year to certified small producers under the Small Producers Program included in the Project shall not pay this mitigation fee based on their very low proportionate roadway use (100 permits are estimated to generally be less than 5% of the permits issued annually).

MM 4.16-2 Applicants who are using an arterial or collector, or Caltrans route, for access to a construction site, shall consult with the Kern County Public Works Department. The Kern County Public Works Department based on established engineering safety standards and current traffic generation data will determine if a Construction Traffic Control Plan is required based on the timing and volume of larger vehicle rigs and the volume of traffic to address public safety and congestion management. If a Plan is required, the Applicant shall prepare and submit a Construction Traffic Control Plan to the Kern County Public Works Department and to the California Department of Transportation (District 9 office) for approval. The Construction Traffic Control Plan must be prepared in accordance with both the California Department of Transportation Manual on Uniform Traffic Control Devices and Work Area Traffic Control Handbook and shall include, but not be limited to, the following issues

a. Timing of deliveries or heavy equipment and building materials.

b. Placing temporary signage, lighting and traffic control devices as necessary to indicate the presence of heavy vehicles and construction traffic.

c. Specifying construction work hours and arrival/departure times outside peak traffic periods.

d. Ensuring access for emergency vehicles to the project site.

e. Any temporary closure of travel lanes or disruptions to street segments and intersections during well development.

f. Maintaining access to adjacent property.

Level of Significance After Mitigation

Project and cumulative impacts are less than significant.

Chapter 5

Consequences of Project Implementation

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Chapter 5
Consequences of Project Implementation

5.1 Environmental Effects Found To Be Less Than Significant

According to Section 15128 of the California Environmental Quality Act (CEQA) Guidelines, an Environmental Impact Report (EIR) must "contain a statement briefly indicating the reasons that various possible significant effects of a project were determined not to be significant and were therefore not discussed in detail in the EIR."

Kern County has engaged the public in the scoping of this Supplemental Environmental Impact Report (SREIR). The contents of *the SREIR (August 2020) and* this SREIR *(October 2020)* were established based on an Initial Study/Notice of Preparation (NOP) prepared in accordance with the CEQA Guidelines and on public and agency comments received during the public scoping period*, as modified with new analysis and information including comments submitted on the SREIR (August 2020)*. Issues that were identified to have no impact or less-than-significant impacts during preparation of the Initial Study/NOP do not need to be addressed further in this SREIR. However, based on the findings of the NOP and the results of scoping, Kern County has determined that the SREIR must include a detailed analysis of all environmental issues identified in Appendix G of the CEQA Guidelines.

After further study and environmental review in this SREIR, direct and indirect impacts of the oil and gas development and operational activities associated with the implementation of the Amendment to Chapter 19.98 (Oil and Gas Production) and related ordinance amendments to the Kern County Zoning Ordinance Project (not including cumulative impacts) would be less than significant or could be reduced to less-than-significant levels with mitigation measures for the following issue areas:

- Geology and Soils;
- Hazards and Hazardous Materials;
- Land Use and Planning;
- Mineral Resources;
- Population and Housing;
- Recreation;
- Utilities and Services (excluding water supply); and
- Transportation and Traffic.

5.2 Significant Environmental Effects That Cannot Be Avoided

Section 15126.2(b) of the CEQA Guidelines requires that the EIR describe any significant impacts, including those that can be mitigated but not reduced to less-than-significant levels. Potential environmental effects of the proposed Project and proposed mitigation measures are discussed in detail in Chapter 4 of this EIR. The following environmental impacts were determined to be significant and unavoidable (Table 5-1).

Table 5-1: Summary of Unavoidable Significant Adverse Impacts of the Project

Resources	Project Impacts	Cumulative Impacts
Aesthetics and Visual Resources	Although implementation of mitigation measures would reduce the adverse visual changes experienced at individual key observation point locations, there are no mitigation measures that would preserve the existing character and quality of the Project Area and its surroundings. Project-related oil and gas activities would continue to produce visible changes to the existing environment and the resultant visual impact is considered **significant and unavoidable**. The Project has the potential to create a new source of substantial light or glare that would adversely affect day or nighttime views in the area. After implementation of MM 4.1-6, this impact would remain **significant and unavoidable.**	The oil and gas industry has a visible presence on the landscape of the San Joaquin Valley Floor and, the Project in combination with the implementation of other reasonably foreseeable oil and gas projects will continue to result in adverse visible changes within Kern County. Therefore, the Project's cumulative contribution after implementation of the recommended mitigation measures would remain cumulatively **significant and unavoidable** as a result of these changes in visual character and quality.
Air Quality	The construction and operational activities of oil and gas activities that would be authorized under the Project would result in an increase of criteria pollutants (oxides of nitrogen [NO_X], volatile organic compounds [VOCs], carbon monoxide [CO], particulate matter less than 10 microns and less than 2.5 microns in diameter [$PM_{10]}$ and $PM_{2.5}$, respectively]) in excess of the recommended criteria pollutant significance thresholds adopted by the San Joaquin Valley Air Pollution Control District (SJVAPCD) Board. Therefore, the proposed Project would result in a cumulatively considerable net increase of criteria pollutants (NO_X, PM_{10}, $PM_{2.5}$, CO, and SO_2) emissions	The construction and operational activities of oil and gas activities that would be authorized under the Project would result in an increase of criteria pollutants (oxides of nitrogen [NO_X, volatile organic compounds [VOCs,], carbon monoxide [CO, particulate matter less than 10 microns and less than 2.5 microns in diameter [PM_{10}, and $PM_{2.5}$, respectively]) in excess of the recommended criteria pollutant significance threshold adopted by the SJVAPCD Board. Emission sources in Kern County contribute between 11% and 21% of criteria pollutant emissions in the San Joaquin Valley Air Basin. The

Table 5-1: Summary of Unavoidable Significant Adverse Impacts of the Project

Resources	Project Impacts	Cumulative Impacts
	for which the San Joaquin Valley Air Basin (SJVAB) is in non-attainment. After implementation of MM 4.3-1 through MM 4.3-4, and MM 4.3-8, impacts would remain **significant and unavoidable**. The Project would expose sensitive receptors to substantial pollutant concentrations. With implementation of MM 4.3-5, MM 4.3-6, and MM 4.3-9, impacts would remain **significant and unavoidable**. The Project would continue to generate odors. With implementation of MM 4.3-7, impacts would remain **significant and unavoidable**.	Project would contribute between 2% and 14% of these pollutants in the San Joaquin Valley Air Basin or between 19% and 97% of Kern County's contribution. This analysis indicates that most sulfur dioxide (SO_2) emissions in Kern County would originate from oil and gas activities. Therefore, the proposed Project would have a **cumulatively considerable** contribution of criteria pollutant (NO_X, PM_{10}, $PM_{2.5}$, CO, and SO_2) emissions to the Kern County portion of the SJVAB. After implementation of MM 4.3-8, impacts would remain **significant and unavoidable**.
Agricultural Resources	There are no feasible mitigation measures to reduce the Project's potential to convert prime farmland, unique farmland, or farmland of statewide importance to non-agricultural use and this impact would be **significant and unavoidable**. The Project has the potential to involve other changes in the existing environment which, because of their location or nature, could result in the conversion of farmland to non-agricultural use or conversion of forest land to non-forest use. With implementation of MM 4.2-1, this impact would remain **significant and unavoidable**.	The geographic scope for cumulative impacts to agricultural and forest resources encompasses the whole of Kern County. The oil and gas exploration and production activities that would be authorized through implementation of the proposed Project, along with projected population growth, could result in **significant and unavoidable** cumulative impacts on farmland conversion.
Biological Resources	None.	Future oil and gas exploration and production activities related to the proposed Zoning Ordinance amendment could contribute to a significant cumulative impact on Project Area biological resources because future use and development of federal, state, and incorporated urban lands are not within the County's jurisdiction or control. Future land uses and development could affect biological resources in each of these jurisdictions and would be undertaken as independent actions with associated impacts, avoidance and minimization requirements, and mitigation, if

Table 5-1: Summary of Unavoidable Significant Adverse Impacts of the Project

Resources	Project Impacts	Cumulative Impacts
		required, under applicable federal, state, regional and local agency law. Impacts would remain **significant and unavoidable** with mitigation.
Cultural Resources	None.	The geographic scope for cumulative impacts to cultural and paleontological resources includes the area within a one-mile radius from the Project Area. Cumulative impacts could result when paleontological, historical, and archaeological resources or human remains cannot be avoided by future projects. For paleontological and archaeological resources, it is important to recover a scientifically significant sample so the information can be preserved. For historic buildings and structures, detailed recordings, including measured drawings and photographs, can preserve the information. For human remains, reburial in a location not slated for future development can protect those remains from future disturbance. There could be **significant cumulative impacts** to paleontological, historical, and archaeological resources or human remains as a result of the oil and gas exploration and production activities that would be authorized under the Project. Implementation of best professional practices would reduce many impacts to a less than significant level. However, buried archaeological and paleontological resources could be damaged or destroyed. Direct mitigation using the measures above would reduce most of these impacts to a **less than significant level**.

Table 5-1: Summary of Unavoidable Significant Adverse Impacts of the Project

Resources	Project Impacts	Cumulative Impacts
Greenhouse Gases	The Project has the potential to conflict with an applicable plan, policy or regulation adopted for the purpose of reducing the emissions of greenhouse gases. With the implementation of MM 4.7-5, the impact would remain **significant and unavoidable.**	The geographic scope for cumulative impacts for GHGs includes the area within 6 miles of the external Project Area boundary, and areas (e.g., incorporated cities) within the Project Area. Climate change impacts are inherently global and cumulative, and not Project specific. While implementation of MM 4.7-1 through MM 4.7-3 and the 2014 Regional Transportation Plan mitigation measures would encourage reduction in GHG emissions at a regional level, they do not provide a mechanism that guarantees GHG emission reductions on a cumulative basis. The Project's cumulative contribution after implementation of the recommended mitigation measures would remain **cumulatively significant and unavoidable** as a result of the GHG emissions associated with the Project.
Hydrology and Water Quality	The Project has the potential to substantially decrease groundwater supplies or interfere substantially with groundwater recharge such that the Project may impede sustainable groundwater management of the basin or conflict with or obstruct implementation of a water quality control plan or sustainable groundwater management plan<u>. *MM 4.17-3 and MM 4.17-4 will ensure that future activities permitted under the Project will provide regional groundwater management agencies with sufficient information, including groundwater use from metered wells, to integrate Project-related groundwater use with the development of a comprehensive sustainable groundwater management solution for basins and subbasin in the Project Area.*</u> As discussed in Section 4.9, Hydrology and Water Quality, there is no feasible mitigation to reduce this impact, which would be **significant and unavoidable**.	The Project's increased oil and gas use of domestic and irrigation quality water, although relatively small in comparison to other uses, is a significant impact and contributes to a cumulatively significant impact to sustainable groundwater management and sustainable groundwater management plan implementation. <u>*MM 4.17-5 provides funds that will mitigate for the Project's fair share of cumulative impacts to disadvantaged communities that are insufficiently considered in the existing SGMA process.*</u> As discussed in Section 4.9, Hydrology and Water Quality, there is no feasible mitigation to reduce this impact, which would be **significant and unavoidable**.

Table 5-1: Summary of Unavoidable Significant Adverse Impacts of the Project

Resources	Project Impacts	Cumulative Impacts
Noise	The Project could generate a substantial temporary or permanent increase in ambient noise levels in the vicinity of the Project. Although the construction and operational noise would be mitigated to the level of standards established in the local general plan due to oil and gas activities authorized under the Project, the sensitivity of sensitive receptors to noise in excess of the their ambient experience is considered significant. With the implementation of MM 4.12-1 and MM 4.12-2, impacts would remain **significant and unavoidable**. The Project, located within the vicinity of a private or public airstrip, could expose people residing or working in the Project Area to excessive noise levels. With the implementation of MM 4.12-1 and MM 4.12-2, impacts would remain **significant and unavoidable**.	The Project, in combination with other existing or reasonably foreseeable projects, could result in cumulative impacts on noise receptors due to noise levels in excess of the County's General Plan standard. Further, the sensitivity of sensitive receptors to noise in excess of their ambient experience is considered significant. With the implementation of MM 4.12-1 and MM 4.12-2, impacts would remain **significant and unavoidable**.
Utilities and Service Systems	The Project would have the potential to have insufficient water supplies to serve both the Project and reasonably foreseeable future development during normal, dry, and multiple dry years. The allocation of water supplies and water demands, the complex laws affecting water rights, the many water districts that have legal jurisdiction over one or more sources of water in the Project Area, the varied technical feasibility of treating produced water, and the produced water reuse opportunities all present complex variables that fall outside the scope of the County's jurisdiction or control under CEQA. <u>*MM 4.17-3 and MM 4.17-4 will ensure that future activities permitted under the Project will provide regional groundwater management agencies with sufficient information, including groundwater use from metered wells, to integrate Project-related groundwater use with the development of a comprehensive sustainable groundwater management solution for basins and subbasin in the Project Area.*</u> As discussed in Section 4.17, Utilities and Service Systems, there is no feasible	The geographic scope for cumulative impacts to utilities and service systems includes the area within 6 miles of the external Project Area. Cumulative impacts would be **significant and unavoidable with respect to water supply**<u>*. MM 4.17-5 provides funds that will mitigate for the Project's fair share of cumulative impacts to disadvantaged communities that are insufficiently considered in the existing SGMA process.*</u> For other public utilities, including municipal wastewater treatment, stormwater management, or landfills with mitigation, impacts would be **less than significant** with mitigation measures.

Table 5-1: Summary of Unavoidable Significant Adverse Impacts of the Project

Resources	Project Impacts	Cumulative Impacts
	mitigation to reduce this impact, which would be **significant and unavoidable**.	

5.3 Irreversible Impacts

Section 15126.2(c) of the CEQA Guidelines defines an irreversible impact as an impact that uses nonrenewable resources during the initial and continued phases of the Project. Irreversible impacts can also result from damage caused by environmental accidents associated with the Project. Irretrievable commitments of resources should be evaluated to ensure that such consumption is justified. Oil and gas development and operational activities associated with the implementation of the Amendment to Chapter 19.98 (Oil and Gas Production) and related ordinance amendments to the Kern County Zoning Ordinance would commit nonrenewable resources during construction and operation activities. During these activities, oil, gas, and other nonrenewable resources would be consumed. Therefore, an irreversible commitment of nonrenewable resources would occur as a result of the Zoning Ordinance. However, assuming that those commitments occur in accordance with the adopted goals, policies, and implementation measures of the Kern County General Plan (KCGP), as a matter of public policy, those commitments have been determined to be acceptable. The KCGP ensures that any irreversible environmental changes associated with those commitments will be minimized.

5.4 Significant Cumulative Impacts

According to Section 15355 of the CEQA Guidelines, the term cumulative impacts "refers to two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts." Individual effects that may contribute to a cumulative impact may be from a single project or a number of separate projects. Individually, the impacts of a project may be relatively minor, but when considered along with impacts of other closely related or nearby projects, including newly proposed projects, the effects could be cumulatively considerable.

This SREIR has considered the potential cumulative effects of the proposed Project. Impacts for the following issue areas have been found to be cumulatively considerable:

- Aesthetics;
- Agriculture and Forest Resources;
- Air Quality;
- Biological Resources;

- Cultural Resources;
- Greenhouse Gases;
- Noise;
- Hydrology and Water Quality; and
- Utilities and Service Systems (Water Supply).

Each of these significant cumulative impacts is discussed in the applicable section of Chapter 4, Environmental Setting, Impacts, and Mitigation Measures, of this SREIR.

5.5 Growth Inducement

The KCGP recognizes that certain forms of growth are beneficial, both economically and socially. Section 15126.2(d) of the CEQA Guidelines provides the following guidance on growth-inducing impacts: a project is identified as growth inducing if it "could foster economic or population growth, or the construction of additional housing, either directly or indirectly, in the surrounding environment." The Project's potential impacts related to growth inducement were assessed in the 2015 FEIR (SREIR Volume 3).

5.6 Energy Conservation

To ensure that energy implications are considered in Project decisions, CEQA requires that EIRs include a discussion of the potential energy impacts of proposed projects, with particular emphasis on avoiding or reducing inefficient, wasteful, and unnecessary consumption of energy (see Public Resources Code section 21100(b)(3)). According to Appendix F of the CEQA Guidelines, the goal of conserving energy implies the wise and efficient use of energy, including: (1) decreasing overall per capita energy consumption; (2) decreasing reliance on natural gas and oil; and (3) increasing reliance on renewable energy sources. The Project's potential energy impacts were assessed in the 2015 FEIR (SREIR Volume 3).

Chapter 6

Alternatives

Chapter 6
Alternatives

6.1 Introduction

The California Environmental Quality Act (CEQA) requires that an Environmental Impact Report (EIR) describe a range of reasonable alternatives to the project or to the location of the project site that could feasibly avoid or lessen any significant environmental impacts of the project while attaining most of the project's basic objectives. An EIR also must compare and evaluate the environmental effects and comparative merits of the alternatives. This chapter describes alternatives considered but eliminated from further consideration, including the reasons for elimination, and compares the environmental impacts of several alternatives retained with those of the Project. *Except where specifically noted, all underlined and italicized text indicates additions, and italicized strikethrough text indicates deletions from the SREIR (August 2020). Non-italicized underlined and strikethrough text is the same as in the SREIR (August 2020).*

The following are key provisions of the CEQA Guidelines (Section 15126.6):

- The discussion of alternatives shall focus on alternatives to the Project or its location that are capable of avoiding or substantially lessening any significant effects of the Project, even if these alternatives would impede to some degree the attainment of the Project objectives, or would be more costly.
- The No Project Alternative shall be evaluated, along with its impacts. The no Project analysis shall discuss the existing conditions at the time the notice of preparation was published, as well as what would be reasonably expected to occur in the foreseeable future if the Project were not approved, based on current plans and consistent with available infrastructure and community services.
- The range of alternatives required in an EIR is governed by a "rule of reason;" therefore, the EIR must evaluate only those alternatives necessary to permit a reasoned choice. The alternatives shall be limited to ones that would avoid or substantially lessen any of the significant effects of the Project.
- For alternative locations, only locations that would avoid or substantially lessen any of the significant effects of the Project need be considered for inclusion in the EIR.
- An EIR need not consider an alternative whose effects cannot be reasonably ascertained and whose implementation is remote and speculative.

The range of feasible alternatives is selected and discussed in a manner to foster meaningful public participation and informed decision making. Among the factors that may be taken into account when addressing the feasibility of alternatives, as described in Section 15126.6(f)(1) of the CEQA Guidelines, are environmental impacts, site suitability, economic viability, availability of infrastructure, general plan consistency, regulatory limitations, jurisdictional boundaries, and whether the project proponent could reasonably acquire, control, or otherwise have access to an alternative site. An EIR need not consider an alternative whose effects could not be reasonably identified, whose implementation is remote or speculative, and that would not achieve the basic project objectives.

As detailed in Chapter 3.1.2, Supplemental Recirculated Environmental Impact Report New and Updated Analysis, new and updated analyses of the five CEQA deficiencies in the 2015 FEIR identified by the Appellate Court have been provided in Chapter 4 of this SREIR (October 2020). Per the CEQA Guidelines, this section discusses alternatives that are capable of avoiding or substantially lessening the Project's potentially significant environmental effects. Section 6.2, Summary of Project Impacts Relevant to Evaluation of Alternatives and Supplemental Analysis, summarizes the potentially significant Project impacts relevant to the ~~this SREIR's~~ evaluation of Project alternatives for the five topic areas in Chapter 4, Environmental Setting, Impacts, and Mitigation Measures *of this SREIR (October 2020)*. Section 6.3, Summary of Project Impacts ~~That Are a Subject of the SREIR and Are~~ Relevant to Evaluation of Alternatives, summarizes the potentially significant Project impacts that are *not* addressed in the supplemental analysis set forth in Chapter 4 of this SREIR *(October 2020)* and that are relevant to ~~*this* SREIR~~ *its* evaluation of Project alternatives. Section 6.4, Project Objectives, restates the Project Proponent's Project objectives. Section 6.5, Process Used to Develop/Screen Alternatives, describes the process used to develop and screen the alternatives evaluated in this SREIR *(October 2020)*. Section 6.6, Alternatives Eliminated from Further Consideration, presents alternatives to the Project that were considered but eliminated for further analysis. Section 6.7, Alternatives to the Project, presents alternatives fully analyzed in this EIR, and provides a comparison of each alternative's environmental effects to those of the Project. Section 6.8, Comparative Impacts of Project to All Alternatives, sets forth two tables that summarize the relative impacts of all of the alternatives as compared to the Project. Section 6.9, Environmentally Superior Alternative, makes a determination about the environmentally superior alternative analyzed in this SREIR *(October 2020)*.

6.2 Summary of Project Impacts Relevant to Evaluation of Alternatives and Supplemental Analysis

Potential significant adverse environmental impacts that would result from the Project that are a subject of this SREIR *(October 2020)* were evaluated in SREIR *(October 2020)* Chapter 4, Environmental Setting, Impacts, and Mitigation Measures. The mitigation measures and impact conclusions are summarized in SREIR *(October 2020)* Chapter 1, Executive Summary, and include a summary chart of impact conclusions for all topic areas. This SREIR *(October 2020)* concludes that the Project has the potential to cause significant and unavoidable environmental impacts in the following categories: Agriculture and Forest Resources, Air Quality, Hydrology and Water Quality, Noise, and Utilities and Service Systems. The ~~SREIR's~~ determinations regarding each impact category evaluated in this SREIR *(October 2020)* are summarized below.

6.2.1 Agriculture and Forest Resources

As explained in SREIR *(October 2020)* Section 4.2, Agricultural and Forest Resources, with mitigation, the Project would have a significant and unavoidable impact with respect to its potential to convert prime farmland, unique farm, or farmland of statewide importance to non-agricultural use. Moreover, *even with mitigation,* the Project would have a significant and unavoidable impact with respect to its potential to involve other changes in the environment which, because of their location or nature, could result in the conversion of farmland to non-agricultural use ~~(or the conversion of forest land to non-forest use), but such impacts would be mitigated to less than significant levels~~. However, the Project would have a less than significant impact related to *conflicts with existing zoning for agricultural use, conflicts with Williamson Act contracts, conflicts with forest land zoning, forestland conversion, and* the productivity of livestock grazing activity within Kern County. Finally, the Project's incremental effects on agricultural resources would be cumulatively considerable and, even with mitigation, this potentially significant cumulative impact would be significant and unavoidable.

6.2.2 Air Quality

As explained in SREIR *(October 2020)* Section 4.3, Air Quality, the Project's potential to conflict with or obstruct implementation of an applicable air quality plan would be less than significant with mitigation. However, even with mitigation, the Project's potential to result in a cumulatively considerable net increase of any criteria pollutant (for which the Project region is in non-attainment under an applicable federal or state ambient air quality standard) would be a significant and unavoidable impact. In addition, the Project would have the potential to expose sensitive receptors to substantial pollution concentrations and, even with mitigation, this impact would be significant and unavoidable. *Similarly, the Project would result in other emissions such as those leading to odors affecting a substantial number of people, and this impact would be significant and unavoidable with mitigation.* Finally, cumulative air emissions would be significant and unavoidable, even with mitigation.

6.2.3 Hydrology and Water Quality

As explained in SREIR *(October 2020)* Section 4.9, Hydrology and Water Quality, the Project's potential to substantially decrease groundwater supplies or interfere substantially with groundwater recharge such that the project may impede sustainable groundwater management of a groundwater basin will be significant and unavoidable. In addition, the Project's potential to conflict with or obstruct implementation of a water quality control plan or sustainable groundwater management plan will be significant and unavoidable. Moreover, the Project would cause a significant and unavoidable impact with respect to its potential to make a cumulatively considerable contribution to cumulative impacts to groundwater elevations and aquifer volumes. *However, with mitigation, the Project would not violate water quality standards or waste discharge requirements or otherwise substantially degrade surface or groundwater quality. And, with mitigation, the Project will not substantially alter existing drainage patterns or place housing in flood hazard areas. Nor would the Project expose people or structures to flooding risks with implementation. Finally, the Project's* *potential cumulative hydrology and water quality impacts would be significant and unavoidable with mitigation.*

6.2.4 Noise

As explained in SREIR *(October 2020)* Section 4.12, Noise, the Project would have the potential to generate or expose persons to noise levels in excess of standards established in the local general plan, noise ordinance, or applicable standards of other agencies. This would result in a substantial *temporary or periodic, and a substantial* permanent increase, in ambient noise levels in the Project vicinity above levels existing without the Project~~ and result in a substantial temporary or periodic increase in ambient noise levels in the Project vicinity above levels existing without the Project~~. All of these impacts would be significant and unavoidable. Likewise, the Project's potential to expose people residing or working in the Project to excessive noise levels caused by those Project activities occurring within the Kern County Airport Land Use Compatibility Plan would be significant and unavoidable. *And t*~~T~~hose Project activities located within the vicinity of a private airstrip have the potential to expose people residing or working in the Project Area to excessive noise levels and this impact would be significant and unavoidable impact. Finally, the Project's potential to make a cumulatively considerable contribution to noise impacts on noise receptors would be significant and unavoidable. *The Project would not expose persons to, or generate, excessive ground-borne vibration or ground-borne noise levels with implementation of mitigation.*

6.2.5 Utilities and Service Systems

As explained in SREIR *(October 2020)* Section 4.17, Utilities and Service Systems, the Project would result in a significant and unavoidable Project-level and cumulative impact with respect to having sufficient water supplies available to serve the Project from existing entitlements and resources. *With mitigation, the Project would not exceed wastewater treatment requirements, result in the relocation or construction of new or expanded water, wastewater treatment or storm water drainage, electric power, natural gas, or telecommunications facilities, the construction or relocation of which could cause significant environmental effects, and would not require or result in the relocation or construction of new or expanded water, wastewater treatment or storm water drainage, electric power, natural gas, or telecommunications facilities, the construction or relocation of which could cause significant environmental effects.*

6.3 Summary of Project Impacts Relevant to Evaluation of Alternatives from 2015 FEIR

Potential significant adverse environmental impacts that would result from the Project that are not a subject of this SREIR *(October 2020)* were evaluated in 2015 FEIR Chapter 4, Environmental Setting, Impacts, and Mitigation Measures. The mitigation measures and impact conclusions are summarized in 2015 FEIR Chapter 1 and in SREIR *(October 2020)* Chapter 1, both of which are titled "Executive Summary" and include a summary chart of impact conclusions for all topic areas.

The 2015 FEIR concludes that the Project has the potential to cause significant and unavoidable environmental impacts in the following categories that are not a subject of the SREIR *(October 2020)*: Aesthetics and Visual Resources, Biological Resources, Cultural and Paleontological Resources, and Greenhouse Gas Emissions and Global Climate Change. Each impact category evaluated in the 2015 FEIR and not a subject of this SREIR *(October 2020)* is summarized below.

6.3.1 Aesthetics and Visual Resources

With respect to its effects on scenic vistas and scenic resources, the Project would have less than significant impacts, without mitigation as explained in the 2015 FEIR Section 4.1, Aesthetics and Visual Resources. However, the Project would substantially degrade the existing visual character or quality of the Project site and its surroundings, even with mitigation, and thus this impact would be significant and unavoidable. Even with mitigation, the Project would create some new sources of light or glare that could adversely affect day or nighttime views in some portions of the Project Area and such impacts would be significant and unavoidable. Finally, the Project's incremental aesthetic effects, combined with the aesthetic effects of other projects, would be cumulatively considerable, a significant impact for which there is no mitigation. Thus, the Project's cumulative aesthetic impact would also be significant and unavoidable.

6.3.2 Agriculture and Forest Resources

As explained in 2015 FEIR Section 4.2, Agricultural and Forest Resources, even without mitigation, the Project would have a less than significant impact with respect to its potential to conflict with existing agricultural zoning, forestry zoning, timberland zoning, and Williamson Act contracts. Likewise, since there is no forest land in the Project Area, the Project would have no impact on forest land resources. Moreover, the Project would not result in the cancellation of an open space contract or farmland security zone contract for any parcel of 100 or more acres.

6.3.3 Air Quality

As explained in 2015 FEIR Section 4.3, Air Quality, with mitigation, the Project would not expose sensitive receptors to substantial pollutant concentrations, and would not create objectionable odors affecting a substantial number of people; however, ambient conditions remain which could cause Project odor-related impacts to remain significant and unavoidable.

6.3.4 Biological Resources

As explained in 2015 FEIR Section 4.4, Biological Resources, with mitigation, the Project's potential to have a direct or indirect adverse effect on any species identified as candidate, sensitive, or special status species in local or regional plans, policies, or regulations or by wildlife agencies would be less than significant. Also, with mitigation, the Project's potential to have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, regulations, or by wildlife agencies would be less than significant. The Project's potential to have a substantial adverse effect on federally protected wetlands through direct removal, filing, or hydrological interruption, or other means would be less than significant with mitigation. Likewise, with mitigation, the Project would not interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory wildlife corridors, or impede the use of wildlife nursery sites. With mitigation, the Project would not conflict with any local policies or ordinances protecting biological resources, such as tree preservation policies or ordinances. Moreover, any adverse impacts related to the Project's potential to conflict with the provisions of a habitat conservation plan, natural community conservation plan, or other approved local, regional, or state habitat conservation plan would be mitigated to a less than significant level. However, the Project would make a cumulatively considerable contribution to cumulative biological resource impacts, even with mitigation.

6.3.5 Cultural and Paleontological Resources

As explained in 2015 FEIR Section 4.5, Cultural and Paleontological Resources, with mitigation, the Project would have a less than significant impact with respect to its potential to cause a substantial adverse change in the significance of an historic resource. Similarly, with implementation of mitigation measures described in Section 4.5 of 2015 FEIR the Project would have a less than significant impact with respect to its potential to cause a substantial adverse chance in the significance of an archaeological resource. Moreover, with mitigation, the Project would have a less than significant impact with respect to its potential to directly or indirectly destroy a unique paleontological resource, site, or feature. With mitigation, the Project would also have a less than significant impact with respect to its potential to disturb any human remains. However, even with mitigation, the Project would make a cumulatively considerable contribution to impacts regarding historic, archaeological, or paleontological resources or human remains, and such impact is significant and unavoidable.

6.3.6 Geology and Soils

As explained in 2015 FEIR Section 4.6, Geology and Soils, with mitigation, the Project would not cause a significant impact with respect to its potential to expose people or structures to risk of loss, injury, or death involving the rupture of a known earthquake fault. The Project, as mitigated, would not expose people or structures to substantial adverse effects including the risk of loss, injury or death involving strong seismic ground shaking. Moreover, with mitigation, the Project would not expose people or structures to substantial adverse effects, including risk of loss, injury, or death involving seismic-related ground failure, including liquefaction. Likewise, with mitigation, the Project would not expose people or structures to substantial adverse effects, including risk of loss, injury, or death involving landslides. The Project, as mitigated, would not result in substantial soil erosion or the loss of topsoil. The Project's potential impacts related to onsite or offsite landslide, lateral spreading, subsidence, liquefaction, or collapse would also be mitigated to a less than significant level. The Project's potential significant impacts related to expansive soils, or soils incapable of adequately supporting the use of septic tanks or alternate wastewater disposal systems where sewers are not available would be less than significant with mitigation. Finally, with mitigation, the Project would not make a cumulatively considerable contribution related to geologic and soil resource impacts.

6.3.7 Greenhouse Gas Emissions and Global Climate Change

As explained in 2015 FEIR Section 4.7, Greenhouse Gas Emissions and Global Climate Change, the Project's potential adverse effects related to direct and indirect greenhouse gas emissions would be mitigated to less than significant levels. However, the Project would conflict with any applicable plan, policy, or regulation adopted for the purpose of reducing emissions of greenhouse gases, thus causing a significant and unavoidable impact, even with mitigation. Finally, the Project would make a cumulatively considerable contribution to a cumulative greenhouse gas emission impact, even with mitigation, and this impact is therefore significant and unavoidable.

6.3.8 Hazards and Hazardous Materials/Public Health Risks

As explained in 2015 FEIR Section 4.8, Hazards and Hazardous Materials/Public Health Risks, with mitigation, the Project would have a less than significant environmental impact with respect to its potential to create a significant hazard to the public or the environment through the routine transport, use, or disposal of hazardous materials. Likewise, with mitigation, the Project would have a less than significant environmental impact with respect to its potential to create a significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment. The Project's potential to handle hazardous or acutely hazardous materials, substance, or wastes within .25 miles of an existing or proposed school would also be mitigated to a less than significant level, as would the Project's potential to create a hazard to the public or the environment as a result of being a site that is included on a list of hazardous materials sites complied pursuant to Government Code Section 65962.5. With mitigation, the Project would have a less than significant impact with respect to its potential to result in a safety hazard for people residing or working within an area covered by an adopted Airport Land Use Compatibility Plan. Even without mitigation, the Project would have a less than significant impact with respect to its potential to result in a safety hazard for people residing or working within the vicinity of an airstrip, and with respect to the Project's potential to impair implementation of, or physically interfere with, an adopted emergency response plan or emergency evacuation plan. The Project's potential to expose people or structures to a significant risk of loss, injury, or death involving wildland fires would be mitigated to a less than significant level, as would the Project's potential to generate vectors or have a component that includes agricultural waste exceeding adopted qualitative thresholds. Moreover, with mitigation, the Project would not make a cumulatively considerable contribution to cumulative hazards and hazardous materials impacts.

6.3.9 Hydrology and Water Quality

As explained in 2015 FEIR Section 4.9, Hydrology and Water Quality, the Project's construction period impacts, including stormwater and runoff impacts, and impacts related to surface or subsurface discharges during well construction, well reworking, and plugging and abandonment, would not violate water quality standards or waste discharge requirements and would be less than significant with mitigation. Likewise, the Project's operational period impacts, including stormwater and runoff impacts, and impacts related to oil, produced water, maintenance and production (including enhanced oil recovery [EOR] and well stimulation), municipal and industrial (M&I) water, and constituent leaks and surface spills or equipment leaks at the surface from ruptured or leaking tanks, pipes, values, hoses, and other process equipment, would not violate water quality standards or waste discharge requirements and would be less than significant with mitigation. Moreover, the Project's operational period impacts related to surface or subsurface discharges during well construction, well reworking, and plugging and abandonment, and surface or subsurface discharges related to produced water or well stimulation, will be less than significant with mitigation and would not violate any water quality standards or waste discharge requirements.

As further explained in 2015 FEIR Section 4.9, Hydrology and Water Quality, with mitigation, the Project will have a less than significant impact with respect to its potential to substantially alter the existing drainage pattern of the Project Area in a manner that would result in substantially erosion or siltation onsite or offsite. Moreover, with mitigation, the Project would not substantially alter the existing drainage pattern of the Project Area, or substantially increase the rate of surface runoff, in a manner that would result in onsite or offsite flooding.

With mitigation, the Project would not create or contribute to runoff water that would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff. Likewise, the proposed Project would not place housing within a mapped 100-year flood hazard area, even without mitigation. Moreover, with mitigation, the Project would not place structures that would impede or redirect flood flows within a 100-year flood hazard. Similarly, Project impacts related to its potential to expose people or structures to a significant risk of loss, injury, or death involving flooding would be mitigated to less than significant levels. Even without mitigation, the Project would not contribute to inundation by seiche, tsunami, or mudflow.

The Project's cumulative impacts to water quality, erosion risks, flooding, and other hydrologic resources would be mitigated to a less than significant level.

6.3.10 Land Use and Planning

As explained in 2015 FEIR Section 4.10, Land Use and Planning, with mitigation, the Project would have a less than significant impact with respect to its potential to physically divide an established community. Likewise, with mitigation, the Project would not conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the Project. Even without mitigation, the Project would not conflict with any applicable habitat conservation plan or natural community conservation plan. Finally, the Project would not make a cumulatively considerable contribution to any cumulative land use or planning impacts, even without mitigation.

6.3.11 Mineral Resources

As explained in 2015 FEIR Section 4.11, Mineral Resources, the Project would have a less than significant impact with respect to its potential to result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state, even without mitigation.

Moreover, the Project would have a less than significant impact, without mitigation, with respect to is potential to result in the loss of availability of a locally important mineral resource recovery site delineated on a local general plan, specific plan, or other land use plan. Finally, the Project would not make a cumulatively considerable contribution to mineral resource impacts, even without mitigation.

6.3.12 Noise

As explained in 2015 FEIR Section 4.12, Noise, the Project's potential to expose persons to, or to generate, excessive ground-borne vibration or ground-borne noise levels would be less than significant and does not require mitigation.

6.3.13 Population and Housing

As explained in 2015 FEIR Section 4.13, Population and Housing, the Project would not induce substantial population growth in the area, either directly or indirectly, even without mitigation. Moreover, the Project would not displace substantial numbers of people or existing housing, necessitating the construction of replacement housing elsewhere, even without mitigation. The Project would not make a cumulatively considerable contribution to population and housing impacts, even without mitigation.

6.3.14 Public Services

As explained in 2015 FEIR Section 4.14, Public Services, with mitigation, the Project would not result in substantial adverse physical impacts associated with the provision of, or need for, new or physically altered governmental facilities, the construction of which could cause significant environmental effects, in order to maintain acceptable service ratios, response times, or other performance objectives for any of the public services, including fire protection, police protection, schools, parks, and other public facilities. Moreover, with mitigation, the Project would not cause a cumulatively considerable contribution to any cumulative public service impacts.

6.3.15 Recreation

As explained in 2015 FEIR Section 4.15, Recreation, the Project would have a less than significant impact, without mitigation, with respect to its potential to result in the increased use of existing neighborhood and regional parks or other recreational facilities such that substantial physical deterioration would occur or be accelerated. Nor would the Project include recreational facilities or require construction or expansion of recreational facilities that might have an adverse physical effect on the environment, even without mitigation. Finally, the Project would not make a cumulatively considerable contribution to impacts on recreation facilities, even without mitigation.

6.3.16 Transportation and Traffic

As explained in 2015 FEIR Section 4.16, Transportation and Traffic, with mitigation, the Project would not conflict with an applicable plan, ordinance, or policy establishing measures of effectiveness for the performance of the circulation system, and would not conflict with an applicable congestion management program. With mitigation, the Project would not result in a change in air traffic patterns that results in substantial safety risks, nor would it substantially increase transportation-related hazards due to a design feature or incompatible use. The Project as mitigated would have a less than significant impact with respect to its potential to result in inadequate emergency access, and would not conflict with adopted policies, plans, or programs regarding public transit, bicycle, or pedestrian facilities, or otherwise decrease the performance or safety of such facilities. Finally, with mitigation, the Project would not make a cumulatively considerable contribution to cumulative transportation or cumulative traffic impacts.

6.3.17 Utilities and Service Systems

As explained in 2015 FEIR Section 4.17, Utilities and Service Systems, with mitigation, the Project would not exceed applicable wastewater treatment requirements. Further, with mitigation, the Project would not require or result in the construction or expansion of new or existing water or wastewater treatment facilities or stormwater drainage facilities in a manner that would cause significant environmental effects. With mitigation, the Project would have a less than significant impact with respect to adequate wastewater treatment and landfill capacities. Moreover, with mitigation, the Project's potential to violate federal, state, and local solid waste statutes would be less than significant. The Project would not cause a cumulatively considerable contribution to any cumulative impacts related to utilities and service system, with the exception of cumulative impacts related to water supplies, as summarized above in Section 6.2.5.

6.4 Project Objectives

6.4.1 County Objectives

The County has defined the following objectives for the Project:

- Update the Kern County Zoning Ordinance (Zoning Ordinance) to create a local permit for oil and gas activities so that County development standards and protective mitigation measures can be implemented for the purpose of reducing or eliminating potential significant adverse environmental impacts, to the extent feasible, of future oil and gas activities, and thereby ensure that current County ordinances implement the Board of Supervisors' policies to protect the health, safety, and general welfare of communities, residents and visitors.
- Encourage ongoing economic development by the oil and gas industry that creates quality, high paying jobs and promotes capital investment in Kern County, which enables the

County to invest in capital improvement projects and social programs, which benefit County residents, retail businesses, and capital industries and ensuring the County's fiscal stability.

- Continue Kern County's ongoing commitment to consult and cooperate with federal, state, regional, and local agencies by periodically reviewing adopted regulations to ensure the long-term viability of Kern County's resources.
- Continue to improve and streamline current energy regulations and increase County monitoring and involvement in state and federal energy legislation.
- Protect areas of important mineral, petroleum, and agricultural resource potential for future use by promoting sustainability and encouraging best management practices), which are mutually beneficial, through strategic short and long range planning.
- Ensure the protection of environmental resources by emphasizing the importance of productive agricultural lands, the encouragement of planned urban growth, the promotion of clean air strategies to address existing air quality issues, and the promotion and implementation of long-term water conservation strategies which will ensure the quality and adequacy of surface and groundwater supplies for future growth of all of Kern County's industries and communities.
- Contain new development within an area large enough to meet generous projections of foreseeable need but in locations that will not impair the economic strength derived from residential developments, agriculture, rangeland, mineral resources, or diminish the other amenities that exist in Kern County.

6.4.2 Applicant Objectives

The Project Proponents have defined the following objectives for the Project:

- Create an effective regulatory and permitting process for oil and gas exploration and production that can be relied on by the County of Kern, as well as the California Geologic Energy Management Division (CalGEM) and other responsible agencies.
- Achieve an efficient and streamlined environmental review and permitting process for all oil and gas operations covered by the proposed Project.
- Provide for economically feasible and environmentally responsible growth of the Kern County oil and gas industry.
- Develop industry-wide best practices, performance standards, and mitigation measures that ensure adequate protection of public health and safety and the environment.
- Increase oil and gas exploration and production in Kern County as a means of reducing California's dependence on foreign sources of energy.

- Increase oil and gas exploration and production in Kern County as a means of increasing employment opportunities and economic prosperity to Kern County's residents, businesses, and local government.

6.5 Process Used to Develop/Screen Alternatives

The alternatives to the Project analyzed in this EIR were selected through a two-step process. First, the County identified potential alternatives based on the comments it received during the EIR scoping process and though internal deliberations that took into consideration the overall Project objectives, and then the County screened out those alternatives that it determined would not meet most of the Project objectives, were infeasible, would not substantially reduce any of the Project's significant environmental effects, or were not reasonable or realistic. Second, the County identified those alternatives that passed the screening criteria and that represent a range of available options to carry forward for analysis in this chapter.

6.6 Alternatives Eliminated from Further Consideration

Kern County considered several alternatives to reduce the Project's significant and unavoidable impacts. Per CEQA, the lead agency may make an initial determination as to which alternatives are feasible and warrant further consideration, and which are infeasible. The following alternatives were initially considered but were eliminated from further consideration in this EIR because they do not meet Project objectives and/or were infeasible.

6.6.1 Drilling Ban on Agriculturally Productive Land Alternative

The Drilling Ban on Agriculturally Productive Land Alternative is identical to the Project, except that it would amend Chapter 19.98 of the Zoning Ordinance to prohibit all new oil and gas exploration, development, and production activities on lands zoned either Exclusive Agricultural (A) or Limited Agricultural (A-1), if such land is being used for agricultural production at the time of drilling permit application. If this alternative were implemented, the Project's agricultural mitigation program, as set forth in Mitigation Measure 4.2-1 would not apply. As a result, there would be less agricultural land conserved in perpetuity in the County. Also, there would be less restoration of agricultural land to productive use through the removal of legacy oil and gas production equipment than would occur under the Project. Moreover, under this alternative, it is more likely that otherwise prohibited oil and gas activities on agricultural lands would be displaced to non-agricultural lands with greater habitat and wildlife resource values than typically found on previously disturbed and actively farmed irrigated agricultural land, potentially causing greater overall environmental harm. This alternative could result in more horizontal and directional subsurface drilling activities needed to recover subsurface oil and gas resources located outside of agricultural zoning districts. This additional horizontal and directional subsurface drilling activity would generate greater toxic air, greenhouse gas, and air quality contaminant emissions than the proposed Project. Horizontal and directional drilling activities generally require more time to complete than vertical drilling activity typically associated with Kern County oil and gas well development. Longer drilling periods require the additional combustion of fossil fuels that cause polluting emissions. In addition, since the vast majority of the Project Area would be off-limits to oil and gas activities under this alternative, Alternative 3 is legally infeasible due to legal restrictions on the County's authority to prohibit access to subsurface mineral interests without liability. For these reasons, the Drilling Ban on Agriculturally Productive Land Alternative is rejected for analysis in this EIR.

6.6.2 Drilling Ban on All Lands Alternative

The Drilling Ban on All Lands Alternative would amend Chapter 19.98 the Zoning Ordinance to prohibit all new oil and gas exploration, development, and production activities within the Project Area. Under this alternative, existing oil and gas wells that are in production on or before the Zoning Ordinance amendment would be authorized to continue, but all existing oil and gas exploration and well development activities would be required to cease and all affected land would be required to be restored to its pre-exploration condition. This alternative assumes that Chapter 19.98 of the Zoning Ordinance would not be amended to establish updated development standards and conditions to address environmental impacts of pre-drilling exploration, well drilling and the operation of wells and other oil and gas production-related equipment and facilities, including exploration, production, completion, stimulation, reworking, injection, monitoring, and plugging and abandonment. Moreover, this alternative assumes that Chapter 19.98 of the Zoning Ordinance would not be amended to establish a new "Oil and Gas Conformity Review" ministerial permit procedure for County approval of future well drilling and operations to ensure compliance with the updated development standards and conditions, and provide for ongoing tracking and compliance monitoring. Finally, this alternative would not be updated to incorporate the Project's relevant proposed development standards into the County's Dark Skies Ordinance or the Zoning Ordinance provisions governing the Floodplain Primary District (FPP), the Petroleum Extraction (PE) Combining District, and Hillside Development.

The Drilling Ban On All Lands Alternative was screened from consideration because it would not achieve most Project objectives. Specifically, this alternative would not achieve four of the County's seven Project objectives, and it would not achieve any of the Applicant's Project objectives. In addition to failing to meet most of the Project objectives, an alternative that completely bans all new oil and gas exploration, development, and production activities is infeasible due to existing legal restrictions on the County's authority to prohibit access to subsurface mineral interests without liability. Since the Drilling Ban On All Lands Alternative is legally infeasible and would not achieve most of the Project's basic objectives it is rejected for analysis in this EIR.

6.6.3 Larger Project Area Alternative

The Larger Project Area Alternative is identical to the Project, except it would enlarge the Project Area described in Chapter 3, Project Description, to include additional acreage in the Project Area's Eastern Subarea. This alternative is feasible, and it would achieve most of the County's and Applicant's Project objectives. This alternative would not, however, reduce of any of the Project's potentially significant adverse environmental effects. By expanding the Project Area to include more acreage available for oil and gas exploration, development, and production activities, the Larger Project Area Alternative would likely have more adverse environmental effects to air quality, biology, cultural resources, and agricultural resources than would the Project. Since this alternative would not reduce any of the Project's significant adverse effects, it is rejected for analysis in this EIR.

6.6.4 More Wells within Project Footprint Alternative

The More Wells Within the Project Footprint Alternative is identical to the Project, except it would also amend Zoning Ordinance Chapter 19.98 to cap the number of oil and gas drilling permits issued by the County at 3,500 per calendar year. As discussed in Chapter 3, Project Description, this EIR assumes that, under Project conditions, ~~2,697~~ <u>*3,647*</u> new producing wells would be drilled in the Project Area on an annual basis over the next 20 years. Under the Permit Cap Alternative, the County would authorize more growth than is assumed by this EIR, but would cap the maximum number of new well permits available to applicants within the Project Area at 3,500 per calendar year. This alternative is screened from consideration in this EIR because a larger number of wells than is contemplated by the Project would not reduce, but may exacerbate, the Project's significant environmental effects.

6.6.5 Fewer Wells within the Project Footprint Alternative with a 2,500-foot Setback from Sensitive Receptors.

The Fewer Wells Within the Project Footprint Alternative with a 2,500-foot Setback is identical to the Project, except it would also amend Zoning Ordinance Chapter 19.98 to cap the number of oil and gas drilling permits issued by the County at 1,500 per calendar year, and impose a 2,500-foot setback from sensitive receptors on wells. Sensitive receptors are defined in the SREIR (October 2020) as "single or multi-family dwelling units, places of public assembly (a legally permitted place where 50 or more people gather together in a building or structure for the purpose of amusement, entertainment, or retail sales), institutions, schools, or hospitals." The 1,500 permits per calendar year amount is significantly fewer than the Project's 2,697 new producing wells assumed by this EIR to be drilled on an annual basis over the next 20 years. The 2,500-foot setback is a request that has been submitted to the County and CalGEM in public forums by a variety of advocates, including local environmental justice groups. No justification for the selection of this specific distance has been submitted to the County but the reason for the request is to provide a distance these advocates believe will protect the health and safety of adjacent community residents from the impacts of oil activities. The SREIR <u>*(October 2020)*</u> and 2015 FEIR have setbacks for health risk and noise impacts and include additional required mitigation measures. The studies show that a setback of 210 feet is sufficient in conjunction with the mitigation measures to reduce the impacts. While the impacts are not all reduced to less than significant, an arbitrary setback cannot be imposed by the Lead Agency. This alternative is screened from consideration in this EIR because while it would be environmentally more protective it, would expose the County to legal liability by restricting the ability (in most cases near sensitive receptors) ability of a mineral holder to access their rights.

A 2500-foot setback, combined with limiting the total number of wells, would mean that some mineral owners' right to access their minerals might be completely extinguished. Well locations that would meet the 2,500-foot setback could already be completely covered with existing wells or other facilities, belonging to another mineral owner or owner who rejected co-location. Such existing locations cannot legally be compelled to allow another mineral owner to drill without subsurface rights. Such distance drilling that might be required to access minerals could also be impeded by existing pipelines, water wells or other conveyances such as canals making any drilling infeasible. As the infeasibility would be based on the County ordinance, the County would be liable for a "takings claim". This would not meet the County objective of updating the Zoning Ordinance "to create a locate permit for oil and gas activities so that County development standards and protective mitigation measures can be implemented . . ." Inherent in all updates to the Zoning Ordinance is that they are consistent with legal foundations of rough proportionality and exactions and can be legally implemented. Further requiring such distance drilling which would create conflicts if allowed. These conflicts would be inconsistent with the County objective of containing "new development within an areas large enough to meet generous projections of foreseeable need but in locations that will not impair the economic strength derived from residential developments, agriculture, rangeland, mineral resources, or diminish the other amenities that exist in Kern County."

Under the Fewer Wells Alternative, up to 1,197 proposed wells may not qualify for drilling permits within any given calendar year. California courts have held that land use regulations that provide "no adequate means of protection of substitute for their right to extract oil" effects a compensable taking of private property (see Braly v. Board of Fire Commissioners of City of Los Angeles157 Cal. App. 2d 608, 616 [1958]; Bernstein v. Bush, 29 Cal. 2d 773, 780 [1947]). Under the Fewer Wells Alternative, once the annual permit cap has been reached in any calendar year, subsequent well permit applicants will have "no adequate means" to exercise their mineral rights and extract oil or gas for the remainder of that year. Though such applicants may qualify for a permit under the following year's cap, per Kavanau v. Santa Monica Rent Control Board 16 Cal. 4th 761, 773 (1997) (Kavanau), property owners temporarily denied all economically beneficial use of their property by regulation "may have the right to just compensation for the temporary taking." Therefore, adoption of the Fewer Wells Alternative could expose the County to hundreds of lawsuits in any given year and potentially substantial just compensation claims. For this reason, this alternative is appropriately eliminated from consideration on the basis that it is legally and economically infeasible.

6.6.6 Offsite Alternative

The Offsite Alternative would carry out the Project in a different area of the County outside of the Project Area described Chapter 3, Project Description. The Project Area, however, was selected because of its proximity to the location of oil and gas resources within the County. As explained in Chapter 3, Project Description, the Project Area was selected because it encompasses the portion of the County in which oil and gas development has historically occurred and is reasonably foreseeable to occur in the coming decades. CalGEM requires oil and gas production wells to be reported, and each is included in an Administrative Boundary area for CalGEM's regulatory oversight purposes. If a new well is drilled outside the Administrative Boundary, the boundary is adjusted by CalGEM once the new well reaches a sustained production output for a year. Historically, more than 95% of oil and gas production occurs within CalGEM's Administrative Area boundaries. Since the Project Area boundary was drawn to encompass the CalGEM Administrative Area boundaries, and land outside of such Administrative Areas where it is probable that oil and gas development will expand, the proposed Project Area best represents the location of probable future oil and gas development in Kern County. Since the fundamental purpose of the Project is to update the County's zoning regulations applicable to future oil and gas development in the County, and since the proposed Project Area represents the area wherein 95% of future oil and gas development is likely to occur, no other sites would be suitable for the Project as proposed. Moreover, it would be technologically infeasible to construct and operate oil and gas drilling facilities that are located outside of the Project Area but also have access to the County's oil and gas resources, which are primarily located inside the proposed Project Area. For these reasons, the Offsite Alternative was dismissed from analysis in this EIR.

It should also be noted that, while CEQA requires an EIR to identify project alternatives, it does not require the EIR to identify alternative project locations. Per the CEQA Guidelines, an EIR must include a reasonable range of "alternatives to the project, *or* to the location of the project" (14 Cal. Code of Regs. Section 15126.6(a) [emphasis added]). Applicable case law recognizes that CEQA grants lead agencies flexibility to elect to analyze either onsite or offsite alternatives, or both (see Mira Mar Mobile Community v. City of Oceanside, 119 Cal. App. 4th 447, 491 [2004]). There is no requirement under CEQA that an EIR always explore an offsite alternative(see California Native Plant Society v. City of Santa Cruz, 177 Cal. App. 4th 957, 933 [2009]). Thus, CEQA does not require this EIR to analyze the Offsite Alternative.

6.6.7 Renewable Energy Alternatives

Oil field operations are generally automated facilities that run 24 hours per day, 7 days per week. These operations have a steady daily energy demand comprised of cyclic demand periods interspersed in any given hour, and will have additional periodic pumping demands that arise when tank volumes cycle (such as stock tanks) and the tank contents are forwarded. Given the continuous operations, equipment will start and stop, as well as load and unload, according a well's particular pumping schedule. Motors in a field or facility are typically cyclic-load duty alternating current motors, controlled by pump-off timers, while tanks may be controlled by interlinked level control "on-off" relays.

Site control and instrument power supplies must be capable of allowing control systems to continually operate all critical electrical components to ensure that spill prevention interlocks will operate without failure. Electrical systems must be robust, easily maintained, and able to withstand high amperage events, full-load trips, frequency instability, overvoltage and under voltage conditions, as well as general loss of power events. The power supply and the well's electrical and control systems must be compatible with the area's hazard designation, including any inverters, battery banks, and charge controllers (Frick and Taylor 1962, 9–35).

A new well, once installed and operating, must have starting and cyclic load following capability, with peak demand ranging from 200% to 275% of the well motor's average energy consumption (actual average energy demand) (Frick and Taylor 1962, 9–35). This cyclic loading and unloading is normally managed through the shared generation resources of the interconnected electricity grid, to which the vast majority of well fields are connected, that maintains the necessary system voltage and frequency stability. Therefore, according to electrical codes and California Public Utilities Commission (CPUC) guidelines and tariffs, any electrical interconnect to the grid must be designed to follow the cyclic loads of the new oil well as if the generation is provided by the serving utility using the pre-existing generating fleet's capability, regardless of origin of the energy.

The Kern Countywide actual average per-well energy consumption is 236 kilowatts per hour (kW-h)/well-day or approximately 0.01 megawatt (MW) on a demand basis (Brandt 2015). Thus, for the 2,697 new wells per year that could be developed pursuant to the Project, approximately 26.5 MW (baseload capacity) of energy would be required per year. The pumping unit cyclic peak demand is 2.75 times the average demand, or roughly 0.0275 MW (Frick and Taylor1962).

This chapter considers multiple alternatives designed to offset some of the Project-related air emissions associated with energy consumption, including greenhouse gas emissions, by considering a version of the proposed Project that would amend Chapter 19.98 of the Zoning Ordinance to require all new oil and gas well drilling operations to be powered by renewable electric generation sources, such as wind and solar technologies, rather than being powered by fossil fuel-powered electric generation sources. In all other respects, the alternatives discussed in this section would be identical to the Project.

Wind Energy Alternative

The Wind Energy Alternative assumes that each new well site permitted in the Project Area would be developed in the same manner as would occur under Project conditions, but also that each new well site would be developed with wind turbines and related facilities in an amount sufficient to provide the electric capacity needed to power well operations at such site.

Wind energy, or electricity generated from wind-power turbines, is a proven and available technology. Like solar energy, however, wind energy is high variable. Both wind and solar energy are non-firm forms of renewable energy and thus are interruptible and not available on a continuous schedule. Moreover, according to the California Energy Commission (CEC), wind resource potential for the Project Area (which does not include the established Kern County Tehachapi Wind Area), is low, with average wind speeds generally below 10.1 miles per hour. Wind turbine starting wind speeds are typically 3 to 4 meters per second or roughly 6 to 10 miles per hour. Given the limited opportunities for wind energy in the valley portion of the county wind energy is less desirable than solar energy for repowering purposes.

Further, even if the Project Area had greater wind resource potential, development of adequate wind facilities to provide the necessary power for the oil and gas activities under the Project would result in significantly greater environmental impacts than the Project. As noted above, oil and gas field operations are 24/7 and have a steady daily demand for electricity. This relatively constant demand around-the-clock does not match well to wind, which is driven by the diurnal cycle in the mountain regions surrounding the Central Valley (particularly the Project study area). The oil fields in the study area are not in locations that are well suited to wind power generation therefore the generation cannot be installed at a new well site on a per new well basis. To be remotely feasible either on a cost-effectiveness basis or technical basis, wind generation energy must be transmitted by conventional grid systems from the wind generating region to the oil-field loads using traditional electrical infrastructure.

As noted, approximately 26.5 MW (baseload capacity) of electricity would be required to offset electricity needs for 2,697 new wells per year requires. Per CEC data, current wind turbines have an actual annual capacity of 25% of the rated capacity based on actual energy produced (CEC 2019). Thus, approximately 106 MW of wind energy capacity would need to be constructed to provide the necessary capacity to offset the energy demand of the oil and gas activities potentially authorized by the Project. Assuming all wells that could be developed pursuant to the Project are developed and operated over the Project life, it would be necessary to construct a range of approximately 1,060 MW to 2,120 MW of wind turbine facilities, or up to one-third of the 5,896 MW of installed wind turbine capacity in the entire state.

According to the American Wind Energy Association, as a general rule of thumb, it requires 60 acres to produce 1 MW of power capacity for land-based wind farms. Annually, to offset energy demand for activities potentially authorized by the Project, wind turbines would need to be constructed on 6,360 acres of land having the proper wind potential, or 127,200 acres of land for the life of the Project. These facilities would also require construction of new substations as well as transmission facilities to interconnect to the grid. Additional ground disturbance would be required for each wind turbine site, thus exacerbating environmental effects associated with well development under Project conditions. The related aesthetic impacts would be significant and unavoidable with conventional wind turbine technology. Communities in which large, utility-scale wind developments have been constructed have also raised concerns about subsonic noise and avian mortality issues. Further, assuming such wind developments would be considered part of the Renewables Portfolio Standard (RPS), including a future RPS standard of 50%, the utility grid owner/operator would have to plan, develop, install, operate, and rate-base the necessary capital to provide the infrastructure to transmit the energy and maintain the system reliability.

Given the scope of the necessary development and the potential significant adverse impacts associated with wind development, further analysis of a wind energy alternative was screened out on the basis that it is infeasible.

Solar Energy Alternative

The Solar Energy Alternative assumes that each new well site permitted in the Project Area would be developed in the same manner as would occur under Project conditions, but also that each new well site would be developed with solar photovoltaic (PV) panels and related facilities in an amount sufficient to provide the electric capacity needed to power well operations at such site.

Solar PV electric generation is commercially available in the Project Area. Like wind power generation, however, solar PV power generation is variable with the potential for sudden changes during daily and seasonal cycles. Moreover, solar PV technology only generates power during daylight hours, whereas the drilling and operation of the new oil and gas wells contemplated by this alternative would be conducted on 24-hour basis, as discussed in Chapter 3, Project Description. Because of variations in insolation (i.e., incoming solar radiation), a solar PV system designed to meet each well site's energy demand would need to store energy during peak insolation hours for use during non-peak times. Solar PV systems typically would provide power at design capacity for 5 to 6 hours per day. Thus, to store sufficient power to provide continuous, uninterrupted power for 24 hours per day consistent with this alternative's electricity demand, the solar PV facility would have to have a capacity four to five times larger than this alternative's electricity demand.

In a situation where sufficient solar PV capacity was constructed and interconnected to the electricity grid for reliability purposes, the solar PV system design capacity could be limited to only deliver the actual average energy 236 kW-h per well-day requirement. The ideal Kern County winter season solar output for fixed panels is 41% of the summer output; thus, at a minimum, the array must have roughly twice the number of panels to deliver equal service during the winter months. CEC data indicates that, on average, all California solar PV facilities (including large scale tracking arrays) deliver at 21% of their rated capacity. Therefore, to ensure the complete offset of electrical energy use, the actual solar facility would need to be sized 4.5 times larger than the base load capacity of 0.0275 MW, resulting in a design capacity of .044 MW per hour. Based on industry standards of 6 to 8 acres of land per 1 MW of solar PV generated powering the activities potentially authorized by the Project using solar PV technology would require 0.6 to 1 acres of arrays per new well, assuming a tie-in to the electricity grid (NREL 2013).

Thus, to offset the total power demand for planned construction and operation of 2,697 wells per year, approximately 119 MW of solar PV capacity would have to be constructed annually on approximately 714 to 952 acres of land. For the life of the Project, assuming full build out of wells authorized by the Project, 2,373 MW of solar PV capacity would need to be constructed on approximately 14,238 to 18,984 acres of land. This scenario would also need sufficient electrical grid infrastructure to ensure grid reliability to comply with CPUC and Federal Energy Regulatory Commission mandatory reliability criteria.

A stand-alone solar option that did not interconnect to the state's electricity grid would result in greater impacts. The design sizing of a stand-alone solar array would require the ability to generate the peak demand of 649 kW-h/day (.27 MW) (year round including winter) and store 16 hours of the non-daytime energy as 432 kW-h (16/24*649 kW-h) stored during the peak generation period and available for any peak demand at night. Using the same assumptions described above concerning winter season solar output and rated capacity, a stand-alone solar array capacity would need to be sized using the peak of design of .28 MW (to ensure delivery of .028 MW in the winter), or 1.7 to 2.8 acres per new well. This would result in development of an additional 4,530 acres of land per year (.28 MW per well x 2,697 wells = 755 MW of solar array capacity x 6 acres per MW). This scenario would also need sufficient electrical grid infrastructure would be needed to ensure grid reliability to comply with CPUC and Federal Energy Regulatory Commission mandatory reliability criteria.

Given the scope of the necessary development and the potential significant adverse impacts associated with solar development, further analysis of a solar energy alternative was screened out on the basis of infeasibility.

Zero Net Gain Alternative

The Zero Net Gain Alternative is identical to the Project, except that it would amend Chapter 19.98 of the Zoning Ordinance to provide that no new oil or gas well drilling permits will be issued by the County, except to the extent that an equal number of existing oil or gas wells have first stopped production and have been abandoned in accordance with state law. Thus, under this alternative, there would be zero net gain in the total number of oil and gas wells operating in the County as compared to baseline conditions. The Zero Net Gain Alternative is rejected for consideration in this EIR because it would not achieve most of the Applicant's Project objectives, including its objectives to (1) achieve an efficient and streamlined environmental review and permitting process for all oil and gas operations covered by the Project; (2) provide for economically feasible and environmentally responsible growth of the Kern County oil and gas industry; (3) increase oil and gas exploration and production in Kern County as a means of reducing California's dependence on foreign sources of energy; and (4) increase oil and gas exploration and production in Kern County as a means of increasing employment opportunities and economic prosperity to Kern County's residents, businesses, and local government. Moreover, this alternative would also not achieve the County's objective of encouraging ongoing economic development by the oil and gas industry that creates quality, high paying jobs and promotes capital investment in Kern County that enables the County to invest in capital improvement projects and social programs.

The Zero Net Gain Alternative is also screened from consideration on the basis that it is legally infeasible. Like the Fewer Wells within the Project Footprint Alternative, the Zero Net Gain Alternative would impose a regulatory cap on the volume of oil and gas production in the Project Area by limiting the number of new well permits on the basis of the number of new well abandonments. Under this regulatory scheme, some applicants may not qualify for drilling permits at any given time. As explained above, California courts have held that land use regulations that provide "no adequate means of protection or substitute for their right to extract oil" effects a compensable taking of private property (see Braly v. Board of Fire Commissioners of City of Los Angeles157 Cal. App. 2d 608, 616 [1958]; Bernstein v. Bush, 29 Cal. 2d 773, 780 [1947]). Under the Zero Net Gain Alternative, applicants denied well permits on the basis that issuance would violate the zero net gain standard, will have "no adequate means" to exercise their mineral rights and extract oil or gas until a sufficient number of existing wells have been legally abandoned. As discussed above, property owners temporarily denied all economic beneficial use of their property by regulation “may have the right to just compensation for the temporary taking” as explained in Kavanau (1997). Therefore, adoption of the Zero Net Gain Alternative could expose the County to hundreds of lawsuits in any given year and potentially substantial just compensation claims. For this reason, the Zero Net Gain is appropriately eliminated from consideration in this EIR on the basis that it is legally and economically infeasible.

6.7 Alternatives to the Project

Alternatives that would avoid or substantially lessen any of the significant effects of the Project and that would feasibly attain most of the basic Project objectives are evaluated in Sections 6.6.1 through 6.6.6, below. Each alternative is discussed with respect to its relationship to the Project’s objectives. Kern County has considered the following alternatives, which are also identified in Table 6-3, Comparison of Alternatives, and discussed individually below:

- Alternative 1 – “No Project” Alternative
- Alternative 2 – CUP Alternative
- Alternative 3 – Reduced Ground Disturbance Alternative
- Alternative 4 – No Hydraulic Fracturing Alternative
- Alternative 5 – Low-Emission EOR Technology Alternative
- Alternative 6 – Recycled Water Alternative
- *Alternative 7 – 2,500-Foot Setback Alternative*

6.7.1 Alternative 1 – “No Project” Alternative

As required by CEQA Guideline §15126.6, this chapter describes and analyzes a “no project” alternative for the purpose of comparing the impacts of approving the Project with the impacts of not approving the Project. Alternative 1, the No Project Alternative, thus assumes that the Project’s proposed amendment to Title 19 of the Zoning Ordinance will not be approved. Accordingly, Alternative 1 assumes that Chapter 19.98 of the Zoning Ordinance will not be amended to establish updated development standards and conditions to address environmental impacts of pre-drilling exploration, well drilling, and the operation of wells and other oil and gas production-related equipment and facilities, including exploration, production, completion, stimulation, reworking, injection, monitoring, and plugging and abandonment. Moreover, Alternative 1 assumes that Chapter 19.98 of the Zoning Ordinance will not be amended to establish a new Oil and Gas Conformity Review ministerial permit procedure for County approval of future well drilling and operations to ensure compliance with the updated development standards and conditions and provide for ongoing tracking and compliance monitoring. Finally, under Alternative 1, the Zoning Ordinance would not be updated to incorporate the Project’s relevant proposed development standards into the County's Dark Skies Ordinance or the Zoning Ordinance provisions governing Hillside Development as well as the FPP and the PE Combining District.

Alternative 1 assumes that oil and gas development and production activities will continue in the Project Area in accordance with the existing Zoning Ordinance. As discussed in Chapter 3, Project Description, Section 19.98.020 of the existing Zoning Ordinance currently authorizes "unrestricted drilling," with no County permit required, in County lands zoned for Exclusive Agriculture (A), Limited Agriculture (A-1), Medium Industrial (M-2), Heavy Industrial (M-3), and Natural Resource (NR), subject to compliance with specified conditions and standards which augment those of CalGEM, the San Joaquin Air Pollution Control District, and applicable fire and safety ordinances and regulations of the County. Thus, in these zoning districts, no review or permit would be required under the No Project Alternative for the drilling of any well intended for the exploration for, or development or production of, oil, gas, and other hydrocarbon substances, or for any related accessory equipment, structure, or facility used as part of the oil and gas production process. However, per the existing Zoning Ordinance, under Alternative 1, drilling would continue to be prohibited within, at minimum, 100 feet of any existing residence without the written consent of the owner thereof.

Under Alternative 1, oil or gas exploration or production would continue to be allowed within the FPP, subject to the Special Review Procedures and Development Standards set forth in Zoning Ordinance Section 19.50.130. Moreover, oil or gas exploration or production would continue to be permitted within a Special Planning District, provided it is consistent with the County General plan land use designation applicable to the subject property and does not create a conflict with the public health, safety, and welfare.

In addition, under Alternative 1, drilling by "ministerial permit" will continue in several zoning districts pursuant to Zoning Ordinance Section 19.98.030. A "ministerial" permit requires an application and review process, but the County does not impose site-specific conditions in such permits and the Applicant is entitled to receive the permit once it demonstrates that relevant standards are met. Under Alternative 1, ministerial permits will continue to be required in the Light Industrial (M-1) and Recreation-Forestry (RF) Districts, subject to specified development standards, which will also continue to apply in Drilling Island Zone Districts, and PE Combining District.

Under Alternative 1, a Conditional Use Permit (CUP) will continue to be required for oil or gas exploration or production in all residential districts, including the Estate District, as well as in the Low, Medium, and High-Density Residential Districts. A CUP will also continue to be required in commercial districts, including the Commercial Office District, Neighborhood Commercial District, General Commercial District, and the Highway Commercial District as well as in the Platted Lands District. Finally, under Alternative 1, oil and gas exploration or production will continue to be prohibited in Mobile Home Park District (Section 19.26.040) and in the Open Space District zoning districts (Section 19.44.040).

Comparative Impacts of Alternative 1

Alternative 1 is environmentally inferior to the proposed Project. As explained in SREIR *(October 2020)* Chapter 3, Project Description, the proposed Project would substantially amend sections of the Zoning Ordinance related to oil and gas exploration and production, including Chapter 19.98, Oil and Gas Production. In doing so, the Project would update and extend to all oil and gas exploration and production facilities development standards and conditions designed to avoid or minimize environmental impacts associated with pre-drilling exploration, well drilling, and the operation of well and other oil and gas production-related equipment and facilities. As discussed in SREIR *(October 2020)* Chapter 3, Project Description, the updated development standards and conditions include several new requirements that would avoid or minimize the impacts of oil and gas exploration and production related to land use, agricultural resources, biological resources, soils and geological resources, water resources, flooding, fire safety, odor management, noise, air quality, cultural resources, lighting, spill prevention and remediation measures, among other categories. The Project would also establish a new Oil and Gas Conformity Review procedure for County approval of future well drilling and operations to ensure compliance with the updated development standards and conditions, and to provide for ongoing tracking and compliance monitoring. If Alternative 1 were adopted, none of the Project's proposed development standards or conditions would be implemented in the County on a consistent basis for all new oil and gas wells in the future and, therefore, Alternative 1 would not achieve the same environmental benefits of the Project. Without implementation of the Project's proposed development standards and conditions, Alternative 1 would have greater environmental impacts than the Project in most impact categories, particularly with respect to impacts related to biological resources, hydrological resources, cultural resources, and noise.

This assessment of comparative impacts as between the Project and Alternative 1 is consistent with the assessment set forth in 2015 FEIR Chapter 6, Alternatives, and it is not changed or materially altered by the supplemental analysis set forth in Chapter 4 of this SREIR *(October 2020)*.

Alternative 1's Relationship to the Project Objectives

If implemented, Alternative 1 would not achieve most of the Project objectives. Alternative 1 would not update the County's Zoning Ordinance to include additional procedures and compliance standards. Alternative 1 would not streamline or provide certainty with respect to the County's current energy regulations, nor would it promote sustainability and BMPs to the same extent as the Project. Compared to the Project, Alternative 1 would not ensure the protection of environmental resources by emphasizing the conservation of productive agricultural lands, the encouragement of planned urban growth, the promotion of clean air strategies, and the promotion of long-term water conservation strategies. Compared to the Project, Alternative 1 would not create an effective regulatory and permitting process for oil and gas exploration and production that can be relied on by the County, CalGEM, and other responsible agencies. Since Alternative 1 would not implement the Project's proposed development standards and conditions, it would not ensure future oil and gas development in a manner that avoids impairing the economic strength derived from residential developments, agricultural, rangeland, mineral resources, other amenities that exist in Kern County.

Finally, Alternative 1 would not encourage ongoing economic development by the oil and gas industry that creates quality, high paying jobs and proposed capital investment in Kern County.

This assessment of Alternative 1's relationship to the Project objectives is consistent with the assessment set forth in 2015 FEIR Chapter 6, Alternatives, and it is not changed or materially altered by the supplemental analysis set forth in Chapter 4 of this SREIR *(October 2020)*.

6.7.2 Alternative 2 – Conditional Use Permit Alternative

Under Alternative 2, the CUP Alternative, all new oil and gas exploration, development, and production activities would be permitted in the Project Area only upon County's issuance of a conditional use permit that authorizes such activities. Under Alternative 2, Chapter 19.98 of the Zoning Ordinance would be amended to eliminate Sections 19.98.020 (Unrestricted Drilling) and 19.98.030 (Drilling By Ministerial Permit), and amend Section 19.98.040 to require a conditional use permit for new oil and gas development and production activities in the following zoning districts: Exclusive Agriculture; Limited Agriculture; Medium Industrial; Heavy Industrial; Natural Resource; Light Industrial; Recreation-Forestry; Estate District; Low, Medium, and High-Density ; Commercial Office; Neighborhood Commercial; General Commercial; Highway Commercial; Platted Lands; FPP; and Special Planning. Conforming amendments would also be made to the Zoning Ordinance chapters applicable to each of the above zoning districts to clarify that oil and gas exploration, development and production activities are conditionally permitted uses within such districts. In effect, Alternative 2 would amend the Zoning Ordinance to eliminate all unrestricted, and ministerial approval of, oil and gas exploration, development, and production activities. Under Alternative 2, such activities would only be permitted upon issuance of a conditional use permit in all zoning districts, except the Mobile Home Park District and the Open Space District, where new oil and gas development and production activities would continue to be prohibited.

Like the Project, Alternative 2 would amend Zoning Ordinance Chapter 19.98 to establish updated development standards and conditions to address environmental impacts of pre-drilling exploration, well drilling and the operation of wells and other oil and gas production-related equipment and facilities, including exploration, production, completion, stimulation, reworking, injection, monitoring and plugging and abandonment. Unlike the Project, however, Alternative 2 would not amend the Zoning Ordinance to establish a new Oil and Gas Conformity Review procedure to ensure compliance with all of the updated development standards and conditions and provide for ongoing tracking and compliance monitoring. Instead, under Alternative 2, implementation of the updated development standards and conditions would occur on a case-by-case basis as deemed necessary through the standard conditional use permit approval and compliance monitoring processes.

Comparative Impacts of Alternative 2

Although, under Alternative 2, future oil and gas drilling projects in the County would require a discretionary conditional use permit approval from the County that would incorporate site-specific and project-specific conditions of approval to minimize or avoid each project's potential environmental effects, Alternative 2 is ultimately environmentally inferior to the proposed Project.

Whereas the Project would implement a comprehensive avoidance and mitigation program specifically designed to reduce the environmental effects of the County's entire oil and gas industry as a well-planned cohesive whole, Alternative 2 would consider the potential environmental effects each oil or gas well permitted in the County on a case-by-case basis without benefit of a comprehensive industry-wide mitigation strategy specifically designed to address regional conservation priorities. In practice, the Project's ministerial approval procedure would be more protective of the environment overall than would Alternative 2. Under the Project, and as consented to by the Project Proponents, each development standard and condition will apply to every well project irrespective of whether the proposed well development and operations would actually cause the environmental impacts such development standards and conditions are designed to reduce or avoid. Under the Project, future permit applicants will not have the opportunity to avoid compliance with many of the Project's new development standards or conditions by demonstrating that the applicant's project would not cause the impact any such development standard or conditions is intended to reduce or avoid, as might occur for some impact categories under Alternative 2. For example, under the Project's proposed regulatory structure, all Project Area ground disturbance is subject to a 1:1 or 1:0.5 compensatory mitigation requirement, irrespective of whether such disturbance will impact sensitive habitat or special status species. Such mitigation would not be implemented under Alternative 2 without evidence of a foreseeable impact. Thus, the Project is likely to over-mitigate with respect to some oil and gas wells that would be permitted under future Project conditions. Since the Project's comprehensive mitigation program would implement new impact avoidance and minimization measures at a scale that exceeds the impact avoidance and minimization potential of Alternative 2, Alternative 2 is generally environmentally inferior to the Project. The environmental effects of Alternative 2 are comparable to those of the proposed Project.

This assessment of comparative impacts as between the Project and Alternative 2 is consistent with the assessment set forth in 2015 FEIR Chapter 6, Alternatives, and it is not changed or materially altered by the supplemental analysis set forth in Chapter 4 of this SREIR *(October 2020)*.

Alternative 2's Relationship to the Project Objectives

Alternative 2 would achieve most, but not all, of the Project objectives. Although Alternative 2 would update the County's Zoning Ordinance to create a local permit process for oil and gas activities so that County development standards and protective mitigation measures can be implemented, it would not streamline the County's current oil and gas permitting procedures because it would impose a lengthy and cumbersome discretionary permitting process on all new oil and gas development within the County. For example, there are approximately 75 active oil and gas fields in the Project Area and approximately 2,500 wells are drilled year. This would be true if this alternative were modified to only require a CUP for wells proposed to be drilled on split estate lands (i.e., lands where the mineral rights have been severed from the surface rights), as that would require the County to process an estimated 100 CUPs each year, in addition to all other CUP applications submitted to the County that are unrelated to oil and gas activities. The County only has the resources to process approximately 60 CUPs for oil and gas wells each year. Such a process would also discourage, rather than encourage, ongoing economic development by the oil and gas industry, and thus would arguably frustrate this objective.

Alternative 2 would help protect areas of important mineral, petroleum, and agricultural resource potential for future use by promoting long-term water conservation strategies, but not to the same extent as the Project. However, Alternative 2 would not provide sufficient new development within an area large enough to meet generous projections of foreseeable need but in locations that will not impair the economic strength derived from residential developments, agriculture, rangeland, mineral resources, or diminish the other amenities that exist in Kern County. Finally, Alternative 2 would create an effective regulatory and permitting process for oil and gas exploration and production that can be relied on by the County and other responsible agencies, but it would not develop comprehensive mitigation strategy that implements industry-wide best practices, performance standards and mitigation measures that ensure adequate protection of public health and safety and the environment.

This assessment of Alternative 2's relationship to the Project objectives is consistent with the assessment set forth in 2015 FEIR Chapter 6, Alternatives, and it is not changed or materially altered by the supplemental analysis set forth in Chapter 4 of this SREIR *(October 2020)*.

6.7.3 Alternative 3 – Reduced Ground Disturbance Alternative

Alternative 3, the Reduced Ground Disturbance Alternative, is identical to the Project, except that it would prohibit all new well drilling activities outside existing CalGEM-designated "Administrative Boundary" areas and would require subsurface oil and gas to be extracted from surface equipment located within such Administrative Boundary areas. This alternative would also limit the disturbance footprint on existing agricultural lands to requiring clustering of new wells in locations immediately adjacent to existing oil and gas equipment. As discussed in Chapter 3, Project Description, the vast majority of future oil and gas production in Kern County will occur in and adjacent to Administrative Boundary areas. Accordingly, this alternative assumes that subsurface oil and gas resources located outside of existing Administrative Boundary areas could still be accessed from inside existing Administrative Boundary areas through use of directional and horizontal drilling techniques. Thus, Alternative 3's restrictions on oil and gas exploration and development are assumed to be legally feasible.

Like the Project, Alternative 3 would amend sections of the Zoning Ordinance relating to oil and gas drilling, including Chapter 19.98 (Oil and Gas Production) to establish updated development standards and conditions to address environmental impacts of pre-drilling exploration, well drilling and the operation of wells and other oil and gas production-related equipment and facilities, including exploration, production, completion, stimulation, reworking, injection, monitoring and plugging and abandonment. Like the Project, Alternative 3 would amend Zoning Ordinance Chapter 19.98 to establish a new Oil and Gas Conformity Review ministerial permit procedure for County approval of future well drilling and operations within the Project Area to ensure compliance with the updated development standards and conditions and provide for ongoing tracking and compliance monitoring. Unlike the Project, however, no new ground disturbance from well drilling activities would be allowed outside existing Administrative Boundary areas.

Comparative Impacts of Alternative 3

Since Alternative 3 would restrict new oil and gas well surface development to locations within existing Administrative Boundary areas, it will result in less overall ground disturbance than would the Project, which allows for new well development both inside and outside of existing Administrative Boundary areas. Thus, Alternative 3 would have somewhat reduced impacts to agricultural resources, biological resources, aesthetic resources, and hydrologic resources as compared to the Project. Further, Alternative 3 would reduce the Project's significant and unavoidable cumulative aesthetic impacts, though not to a less than significant level.

In addition to its environmental benefits, Alternative 3 would create certain environmental impacts greater than those caused by the Project. Since Alternative 3 would not prohibit new wells outside of existing Administrative Boundary areas, compared to the Project, this alternative would result in more horizontal and directional subsurface drilling activities needed to recover subsurface oil and gas resources located outside Administrative Boundary areas. This additional horizontal and directional subsurface drilling activity would generate greater air quality, greenhouse gas, and toxic air contaminant emissions than would the proposed Project because such activities generally require more time to complete than does the vertical drilling activity typically associated with Kern County oil and gas well development. Longer drilling periods require the additional combustion of fossil fuels that cause polluting emissions. The extended drilling times associated with Alternative 3 would also generate more noise impacts within Administrative Boundary areas than would the Project, and would result in a comparative increase in traffic within and around such Administrative Boundary areas due to the additional trips need to ferry drilling equipment to and from new well sites developed under Alternative 3. Otherwise, the environmental effects of Alternative 3 are comparable to the Project.

Given the size and unconventional geology of the Project Area, it is also reasonable to assume that, in some instances, the owners of mineral interests underlying lands outside of Administrative Boundary areas will not be able to feasibly exercise their mineral rights as a result of the drilling restrictions assumed by this alternative. In such cases, this alternative would arguably destroy all economically beneficial or productive use of such mineral interests, thus exposing the County to economic harm and legal liability. California courts have held that land use regulations that provide "no adequate means of protection of substitute for their right to extract oil" effects a compensable taking of private property (see Braly v. Board of Fire Commissioners of City of Los Angeles157 Cal. App. 2d 608, 616 [1958]; Bernstein v. Bush, 29 Cal. 2d 773, 780 [1947]).

This assessment of comparative impacts as between the Project and Alternative 3 is consistent with the assessment set forth in 2015 FEIR Chapter 6, Alternatives, and it is not changed or materially altered by the supplemental analysis set forth in Chapter 4 of this SREIR *(October 2020)*.

Alternative 3's Relationship to the Project Objectives

Alternative 3 would achieve most of the Project objectives. Alternative 3 would update the County's Zoning Code in a manner similar to the Project, though it would reduce the overall Project surface footprint. Alternative 3 would also encourage ongoing and increased economic development by the oil and gas industry in a manner consistent with the Project objectives, though perhaps not to the same extent as the Project. Like the Project, Alternative 3 would streamline and provide more certainty to the County's oil and gas regulations and environmental review processes. Alternative 3 would also help reduce California's dependence on foreign sources of energy and would accommodate foreseeable need in appropriate locations, provided more oil and gas can be produced through increased horizontal and directional drilling techniques than would occur under the "No Project" scenario. Alternative 3 would also ensure the protection of environmental resources by emphasizing the conservation of productive agricultural lands and through the development and implementation of industry-wide best practices, performance standards, and mitigation measures, though it would have greater overall environmental effects in some impact categories than would the Project, as discussed above.

This assessment of Alternative 3's relationship to the Project objectives is consistent with the assessment set forth in 2015 FEIR Chapter 6, Alternatives, and it is not changed or materially altered by the supplemental analysis set forth in Chapter 4 of this SREIR *(October 2020)*.

6.7.4 Alternative 4 – No Hydraulic Fracturing Alternative

Pursuant to its police power, the County has broad discretion to regulate oil and gas exploration and production activities within its jurisdiction. However, a local government's legal authority to regulate every step in the hydraulic fracturing process is the subject of legal disputes currently pending in certain California courts. Assuming the County has sufficient legal authority to regulate subsurface oil and gas exploration and development activities as contemplated by this alternative, Alternative 4, the No Hydraulic Fracturing Alternative, would implement the Project as proposed, except that it would amend Zoning Ordinance Chapter 19.98 to ban all hydraulic fracturing activities, a form of well stimulation, within the Project Area. In all other respects, the Alternative 4 is the same as the Project.

Alternative 4 would only prohibit hydraulic fracturing in the Project Area, but it would not prohibit acid fracturing or acid matrix well stimulation techniques. Were Alternative 4 approved, however, it is unlikely that the hydraulic fracturing ban would cause an increase in acid fracturing or acid matrix well stimulation in the Project Area. Hydraulic fracturing is a viable well stimulation treatment in diatomite subsurface formations, as explained in Section 4.9, Hydrology and Water Quality. In contrast, acid fracturing and acid matrix stimulation techniques are only viable in carbonate reservoir rocks and siliciclastic reservoir formations, respectively. Thus, acid fracturing and acid matrix techniques do not serve as viable substitutes for hydraulic fracturing. Moreover, as explained in Section 4.9, there are no carbonate reservoir rocks in Kern County oil and gas fields that would be subject to acid fracturing techniques, in any case. A ban on hydraulic fracturing may, however, cause an increased use of EOR techniques in the Project Area.

Comparative Impacts of Alternative 4

In some respects, Alternative 4 is environmentally comparable to the Project. Indeed, as explained in Section 4.9, Hydrology and Water Quality, most wells that are hydraulically fractured in the Project Area are shallow vertical wells installed in diatomite subsurface formations located in the

Western Subarea. Accordingly, in the Central and Eastern Subareas, where little to no hydraulic fracturing is expected to occur, Alternative 4 is essentially the same as Project and would cause generally identical impacts as the Project. Even in the Western Subarea, Alternative 4's environmental effects related to aesthetic, agricultural, and forest resources, biological resources, cultural resources, geology and soils, land use and planning, mineral resources, noise, population and housing, public services, recreation, and utilities and service systems would be generally the same as the Project.

As discussed in 2015 FEIR Section 4.8, Hazards and Hazardous Materials/Public Health Risks, hydraulic fracturing uses a variety of hazardous materials and non-hazardous materials, though the majority of such materials have been determined to have a low hazard potential in terms of oral toxicity and there is no confirmed degradation of groundwater in the Project Area attributable to hydraulic fracturing or to other well stimulation techniques. However, certain hazardous hydraulic fracturing fluid components, such as biocides, corrosion inhibitors and mineral acids used in very small amounts in the hydraulic fracturing process may present concerns for acute toxicity, as discussed in Section 4.8 and Section 4.9. If adopted, Alternative 4 would have reduced environmental impacts associated with hazardous materials transportation and handling, and fewer chemical constituents in produced water, as compared to the Project. As discussed above, however, Alternative 4 could cause an increased use of EOR techniques in the Project Area, which would cause a corresponding increase in the emission of greenhouse gases and criteria air pollutants, as compared to the Project.

As explained by the California Council on Science & Technology (CCST) in its study, *An Independent Scientific Assessment of Well Stimulation in California*, "[t]he majority of impacts associated with hydraulic fracturing are caused by the indirect impacts of oil and gas production enabled by the hydraulic fracturing." According to the CCST, "all oil and gas development causes similar impacts whether the oil is produced with well stimulation or not." The exception to this general rule, however, concerns greenhouse gas emissions.

According to the CCST:

> Fields with lighter oil result in low emissions per barrel of crude produced, while fields with heavier oil have higher emissions because of the need for steam injection during production as well as more intensive refining needed to produce useful fuels such as gasoline. Well stimulation generally applies to reservoirs with lighter oil and consequently smaller greenhouse gas burdens per unit of oil. Oil and gas from San Joaquin Basin reservoirs using hydraulic fracturing have a relatively smaller carbon footprint than oil and gas from reservoirs such as those in the Kern River field that use steam flooding. If well stimulation were disallowed and consumption of oil and gas in California did not decline, more oil and gas would be required from non-stimulated California fields …, possibly with higher emissions per barrel. Consequently, overall greenhouse gas emission due to production could increase if well stimulation were stopped in California. (CCST 2015*a*)

Thus, if well stimulation were disallowed, as contemplated by the No Hydraulic Fracturing Alternative, more oil and gas would be required from non-stimulated California fields. This would likely result in an overall increase in greenhouse gas emissions without an overall increase in other adverse environmental impacts. Accordingly, the No Hydraulic Fracturing Alternative would be environmentally inferior to the Project. It is well settled that an EIR need not consider alternatives that do not offer significant environmental advantages in comparison to the Project. 14 Cal. Code Regs. § 15126.6(b).

This assessment of comparative impacts as between the Project and Alternative 4 is consistent with the assessment set forth in 2015 FEIR Chapter 6, Alternatives, and it is not changed or materially altered by the supplemental analysis set forth in Chapter 4 of this SREIR *(October 2020)*.

Alternative 4's Relationship to the Project Objectives

Alternative 4 would achieve most of the Project objectives to some degree. Alternative 4 would update the County's Zoning Code in a manner similar to the Project, though it would also ban hydraulic fracturing in the Project Area. Alternative 4 would also encourage ongoing and increased economic development by the oil and gas industry in a manner consistent with the Project objectives, though not to the same extent as the Project (unless increases in EOR activities spurred by Alternative 4 are able to offset any decrease in oil and gas production caused by a hydraulic fracturing ban). This alternative would also protect areas of important mineral, petroleum, and agricultural resource potential for future use by promoting sustainability and encouraging BMPs. Like the Project, Alternative 4 would streamline and provide certainty to the County's oil and gas regulations and environmental review processes. Alternative 4 would also help reduce California's dependence on foreign sources of energy and would accommodate foreseeable need in appropriate locations, but perhaps not to the same degree as the Project. Finally, Alternative 4 would ensure the protection of environmental resources through the development and implementation of industry-wide best practices, performance standards, and mitigation measures, though it may have greater overall environmental effects in some impact categories than would the Project, as discussed above.

This assessment of Alternative 4's relationship to the Project objectives is consistent with the assessment set forth in 2015 FEIR Chapter 6, Alternatives, and it is not changed or materially altered by the supplemental analysis set forth in Chapter 4 of this SREIR *(October 2020)*.

6.7.5 Alternative 5 – Low-Emission Enhanced Oil Recovery Technology Alternative

Alternative 5, the Low-Emission EOR Alternative, is identical to the proposed Project, except that the updated development standards and conditions required by the Project's proposed Zoning Ordinance amendment would be expanded to require oil and gas well permit applicants to implement low-emission EOR technology as a condition of permit approval for new and replacement steam generators, and to replace existing steam generators constructed prior to 1990 within five years of enactment of the amended Zoning Ordinance. As explained in Chapter 3, Project Description, EOR is a production technique used to increase the mobility of oil, most commonly through steam injection techniques that reduce the viscosity of the hydrocarbons and allow produced fluids to flow. There are four major types of EOR operations: waterflood; thermal (i.e., steamflood, cyclic steam and in situ combustion); CO_2 or other gas (miscible and immiscible); and chemical/polymer flooding (i.e., alkaline flooding or micellar-polymer flooding). With thermal EOR, steam is injected into a well, which necessitates the installation of steam generators at the well. Steam generators are large heaters that generate steam, usually from produced groundwater. Under Alternative 5, all new and replacement steam generators for thermal EOR activities would be required to implement low-emission steam generation technology, such as the ClearSign Duplex Tile combustion technology or the equivalent. In all other respects, Alternative 5 would be identical to the Project.

Comparative Impacts of Alternative 5

Alternative 5's environmental effects would be generally the same as the Project, except Alternative 5 would have reduced air quality and greenhouse gas impacts compared to the Project. With respect to new Project-level emissions, Alternative 5 and the Project, as mitigated, would have similar air quality and greenhouse gas impacts. However, Alternative 5's additional requirement that certain existing pre-1990 steam generators be replaced within five years of enactment of the amended Zoning Ordinance would further reduce emissions that are included in the baseline emissions inventory, a reduction that would not occur under Project conditions. In addition, it is expected that Alternative 5's required low-emission steam generation technology would be more fuel efficient than Project technology, thus reducing overall fuel transportation and handling impacts, as compared to the Project. Alternative 5 is not expected to cause any environmental impacts that would be greater than those caused by the Project.

This assessment of comparative impacts as between the Project and Alternative 5 is consistent with the assessment set forth in 2015 FEIR Chapter 6, Alternatives, and it is not changed or materially altered by the supplemental analysis set forth in Chapter 4 of this SREIR *(October 2020)*.

Alternative 5's Relationship to the Project Objectives

Alternative 5 would meet most of the Project objectives. This alternative would update the County's Zoning Ordinance to create a local permit for oil and gas activities so that County development standards and protective mitigation measures can be implemented for the purpose of reducing or eliminating potential significant adverse environmental impacts, to the extent feasible, of future oil and gas activities. This alternative would continue to improve and streamline current energy regulations and increase County monitoring and involvement in state and federal energy legislation. Alternative 5 would also protect areas of important mineral, petroleum, and agricultural resource potential for future use by promoting clean air strategies to address existing air quality issues. Alternative 5 would provide sufficient new development within an area large enough to meet generous projections of foreseeable need but in locations that will not impair the economic strength derived from residential developments, agriculture, rangeland, mineral resources, or diminish the other amenities that exist in Kern County. Alternative 5 would also create an effective regulatory and permitting process for oil and gas exploration and production that can be relied on by the

County and other responsible agencies, and it would develop industry-wide best practices, performance standards and mitigation measures that ensure adequate protection of public health and safety and the environment. Finally, this alternative also has the potential to increase oil and gas exploration and production in Kern County as a means of (1) reducing California's dependence on foreign sources of energy, and (2) increasing employment opportunities and economic prosperity to Kern County's residents, businesses, and local government.

This assessment of Alternative 5's relationship to the Project objectives is consistent with the assessment set forth in 2015 FEIR Chapter 6, Alternatives, and it is not changed or materially altered by the supplemental analysis set forth in Chapter 4 of this SREIR *(October 2020)*.

6.7.6 Alternative 6 – Recycled Water Alternative

Under Alternative 6, the Recycled Water Alternative, the Applicants would be required to treat an amount produced water that is currently being disposed of via underground injection wells which is equivalent to the amount of M&I water used in Applicant's operations. The produced water reuse goal is 30,000 acre-feet (AF) per year, which would offset more than the current use of imported water and groundwater from non-oil bearing zones by the oil and gas industry. Such produced water would be required to be treated, recycled and put to an alternate use such as agricultural irrigation to the extent feasible. As explained in Section 4.9, Hydrology and Water Quality, oil-bearing formations in the Project Area include a mixture of usually saline or other poor-quality groundwater and hydrocarbons. Production wells extract a mixture of water and hydrocarbons that is separated in surface facilities, typically a series of tanks or "tank batteries," where lighter oil and gas compounds are isolated and skimmed from the heavier water. Residual water generated by the hydrocarbon separation process is generally referred to as "produced water" in the context of oil and gas exploration and production. Under current practices, much of this produced water is used in future oil and gas recovery operations (e.g., steam and water flooding) and for oil and gas maintenance activities, and the remainder is disposed of primarily through underground injection wells. In some portions of the Project Area, produced water is also treated and reused for agricultural irrigation purposes, as explained in Section 4.9.

Produced water is often treated to remove salts and other constituents for reuse in the oil and gas exploration and production process. As explained in Section 4.9, over 234,000 AF of produced water was extracted in 2010, and by 2035 the annual amount of produced water could increase to more than 324,000 AF. As explained in Section 4.17, Utilities and Service Systems, about 38% of the total volume of produced water in 2012, or 88,812 AF, was reused for water and steam injections, pressure maintenance, well pulling, coil tubing activities, dust control, and surface facility construction. Produced water demand for oil and gas reuse is expected to rise to 122,234 AF by 2035. In addition, about 32,771 AF per year of relatively high-quality produced water from oilfields located along the base of the Sierra Nevada in the Eastern Subarea is provided to Cawelo Water District for agricultural reuse. Produced water reuse for irrigation requires additional filtration and treatment to meet applicable water quality standards.

Under Alternative 6, applicants would be required to fund treatment and conveyance facilities for produced water for local reuse (such as agricultural irrigation). For purposes of analysis in this EIR, this Alternative assumes (1) that water treatment facilities would be located in Tier 1 areas more than 1,000 feet away from the nearest sensitive receptor; (2) that treatment facilities would be subject to New Source Review permit requirements (where applicable), including use of best available control technology to minimize air emissions; (3) that remaining criteria and greenhouse gas emissions would be fully offset; and (4) and that waste products (including residuals from treated produced water) would be disposed of in accordance with applicable law. In all other respects, Alternative 6, the Recycled Water Alternative, is identical to the proposed Project.

Comparative Impacts of Alternative 6

As explained in Section 4.17, Utilities and Service Systems, the extent to which additional produced water can be reused in the Project Area depends on several facts, including produced water quality. Produced water is generated from hydrocarbon-bearing formations that are not suitable for M&I purposes due to typically high levels of total dissolved solids, hydrocarbon and related constituents, boron, chloride, and other potential constituents of concern. As discussed in Section 4.9, Hydrology and Water Quality, the Central Valley Regional Water Quality Control Board has determined that, in certain instances, even relatively high-quality produced water present in certain oilfields in the Eastern Subarea has, on occasion, not met applicable arsenic or oil and grease water quality standards. Given the range of constituents present in some produced water, it is unlikely that all produced water can be feasibly treated for reuse under this alternative. Nevertheless, the water treatment facilities to be funded under Alternative 6 could feasibly treat some additional produced water for agricultural and other uses, thus reducing Project hydrology and water quality impacts associated with the extraction of produced water in Project Area wells, and potentially offsetting some oil and gas M&I water demand. This alternative would also create a potential regional benefit by adding to the net supply of irrigation water available for use in the County. However, construction and operation of the Alternative 6 treatment plants would result in adverse environmental effects otherwise avoided by the Project, including adverse impacts to aesthetic, agricultural, biological, and cultural resources, noise, and traffic. Finally, in its comment letter on the 2015 FEIR, CalGEM expressed concern that the treatment and reuse of produced water for agricultural or other uses may adversely affect the balance between production and injection that needs to be maintained to prevent subsidence in the Project Area. CalGEM is mandated to prevent subsidence and is concerned that if produced fluids are redirected to other beneficial uses there may not be fluid available to be put to use in subsidence abatement, a view with which the County concurs. In all other respects, the environmental effects of Alternative 6 are comparable to the Project.

This assessment of comparative impacts as between the Project and Alternative 6 is consistent with the assessment set forth in 2015 FEIR Chapter 6, Alternatives, and it is not changed or materially altered by the supplemental analysis set forth in Chapter 4 of this SREIR *(October 2020)*.

Alternative 6's Relationship to the Project Objectives

Alternative 6 would meet most of the Project objectives. This alternative would update the County's Zoning Ordinance to include additional procedures and compliance standards that address changes in laws and regulations by other agencies, and it would continue to improve and streamline current energy regulations and increase County monitoring and involvement in state and federal energy legislation. Alternative 6 would also protect areas of important mineral, petroleum, and agricultural resource potential for future use by promoting long-term water conservation strategies which will ensure the quality and adequacy of surface and groundwater supplies for future growth of all of Kern County's industries. Alternative 6 would provide sufficient new development within an area large enough to meet generous projections of foreseeable need but in locations that will not impair the economic strength derived from residential developments, agriculture, rangeland, mineral resources, or diminish the other amenities that exist in Kern County. The increased cost of oil and gas development and production attributable to this alternative's funding obligations could, however, discourage ongoing economic development by the oil and gas industry that creates quality, high paying jobs and promotes capital investment in Kern County. Offsetting the industry's M&I water use would require major capital investment, including construction of advanced water treatment systems to allow produced water for agricultural irrigation (e.g., reverse osmosis to remove dissolved solids, chemical treatment to remove trace metals such as arsenic and boron) and construction of new infrastructure (e.g., pipelines and storage facilities) to convey water from fields in which it is produced to agricultural users. This alternative could also require concentrating exploration and production in reservoirs where produced water is fresh enough to warrant use for agricultural irrigation. However, Alternative 6 would create an effective regulatory and permitting process for oil and gas exploration and production that can be relied on by the County and other responsible agencies, and it would develop industry-wide best practices, performance standards and mitigation measures that ensure adequate protection of public health and safety and the environment.

This assessment of Alternative 6's relationship to the Project objectives is consistent with the assessment set forth in 2015 FEIR Chapter 6, Alternatives, and it is not changed or materially altered by the supplemental analysis set forth in Chapter 4 of this SREIR *(October 2020)*.

6.7.7 *Alternative 7 – 2,500-Foot Setback Alternative*

Local jurisdictions in other states, including Colorado, New Mexico, Oklahoma, Pennsylvania, Texas, and Wyoming, have established minimum setback distances between oil and gas facilities and sensitive land uses such as residences, most ranging between 500 and 1,500 feet (Minner 2015). As noted in a detailed analysis of setback distances in the Dallas-Fort Worth, Texas, area, "there is no uniform setback distance, distances have increased over time, and, rather than technically-based, setbacks are political compromises" (Fry 2013). Moreover, to the extent that some setbacks in other areas of the country may be based on scientific analysis, the drilling practices and topographic, meteorological, and geological conditions differ from those in Kern County. As discussed in Section 4.2, Agricultural Resources, formations in Kern County are largely dominated by complex structural geometry where faulting creates discontinuous producible reservoirs. By contrast, in other regions of the United States, geological formations are more homogeneous, and producible reservoirs are laid out in flat and long intervals suitable for access by horizontal drilling, with accompanying increased emissions and other impacts.

Other local jurisdictions within California have also adopted setbacks between oil and gas sites and sensitive land uses, most commonly set at 300 feet; for example, those adopted by Los Angeles County and the Cities of Arvin, Huntington Beach, and Signal Hill. As in other states, local setback distances in California are often the result of political compromises rather than scientific analysis. The Ventura County 2040 General Plan, adopted in September 2020, established a 1,500-foot setback between new oil wells and residences and a 2,500-foot setback from schools (Ventura County 2020). Currently, Ventura County's General Plan 2040 is being challenged in court. No other local jurisdiction in the United States has established a 2,500-foot setback for oil and gas sites.

To protect against health risks from impacts to air quality, MM 4.3-5 requires that the Site Plan for a proposed activity include a Site Vicinity Figure showing the location of any sensitive receptor(s) located within 4,000 feet (over 3/4 of a mile) of the construction site. If sensitive receptors are present within 4,000 feet of the well site, the distance setback requirements derived from the Health Risk Assessment (HRA) for construction activities are triggered. MM 4.12-1 and 4.12-2 establish similar standards to address the exposure of sensitive receptors to noise during construction and operations. Under MM 4.12-1 and 4.12-2, if sensitive receptors are present within the screening contours, there is a presumption that noise levels will exceed applicable thresholds. If the permit applicant can demonstrate based on site-specific measurements in an Acoustic Noise Reduction Report that the activities will not exceed the Noise Standard, or if the applicant can implement attenuation measures as documented in the Acoustic Noise Reduction Report to achieve the applicable noise standard, then the applicant may conduct activities inside the screening distances specified in those mitigation measures. However, in no case may an applicant site a well closer than 210 feet to any sensitive receptor, with the distance being increased specifically for school property to 300 feet. As described in Section 4.3, Air Quality, and Section 4.13, Noise, the setbacks in these mitigation measures are based specifically on local conditions, equipment, and drilling practices utilized in Kern County and incorporate numerous conservative assumptions to establish scientifically supported, safe setbacks for sensitive receptors. Further, the mitigations for reduction of criteria pollutants to the equivalent of "no net increase" are part of the comprehensive package of mitigation along with the setbacks. Accordingly, the scientifically based setbacks and mitigation distance triggers established in these mitigation measures are more relevant than setbacks in other states and in California, especially where those other setbacks are based on policy rather than risk assessments.

Alternative 7, the 2,500-Foot Setback Alternative, is identical to the Project, except it would also amend Zoning Ordinance Chapter 19.98 to impose a 2,500-foot setback from sensitive receptors on wells. Sensitive receptors are defined in the SREIR (October 2020) as "single or multi-family dwelling units, places of public assembly (a legally permitted place where 100 or more people gather together in a building or structure for the purpose of amusement, entertainment, or retail sales), institutions, schools, or hospitals." A requirement that new oil and gas wells be set back 2,500 feet from sensitive receptors has been requested of the County and CalGEM in various public forums by a variety of advocates, including local environmental justice organizations. Although the Project includes setbacks to reduce health risk and noise impacts, advocates for a 2,500-foot setback assert that Alternative 7 would be more protective of sensitive receptors than would the Project by requiring even more space between permitted oil and gas wells and such sensitive *receptors. As explained below, expert evidence indicates that Alternative 7 would not result in less severe environmental impacts than would the Project. However, given the public interest in a 2,500-foot setback, and in the interest of full disclosure, Alternative 7 has been carried forward for analysis as set forth herein.*

Comparative Impacts of Alternative 7

An alternative that requires a 2,500-foot setback from all oil and gas activities would not result in less severe environmental impacts than would the Project. As described under Impact 4.3-3 in Section 4.3, Air Quality of the SREIR (October 2020), three HRAs were completed for the Project: two single-well HRAs and one multi-well HRA. The single-well HRAs found that, with the setbacks in MM 4.3-5, health risk from Project activities would be less than significant. MM 4.3-5 requires setbacks ranging from 0 to 367 feet, depending on the depth of the well and the subarea in which it is drilled. The multi-well HRA assumed that forty-eight 13,000-foot wells would be drilled in concentric circles around a sensitive receptor, 12 at 1/8 of a mile, 12 at 1/4 of a mile, 12 at 3/4 of a mile, and 12 at 1 mile. This scenario is extremely conservative given that that there have historically been 4 to 12 drill rigs in Kern County at any given time between 2015 and 2020 and that it would take eight rigs drilling continuously for almost a year, all in one location, in order to drill forty-eight 13,000 foot wells (Baker Hughes 2020). The multi-well HRA found that health risk, even from this very conservative scenario, would only be 9.3 in 1 million, well below the San Joaquin Valley Air Pollution Control District (SJVAPCD) threshold of 20 in 1 million.

As explained in Section 4.3.4, Air Quality, Impacts and Mitigation Measures, under Impact 4.3-3, the HRAs included multiple conservative assumptions, including that all phases of drilling occurred concurrently, that each well would have an associated mud sump with emissions, that well re-work would occur on every well every other year, and that wells in the multi-well HRA would be 13,000 feet, considerably deeper than the average well in Kern County (only 3% of wells are deeper than 10,000 feet). While the inclusion or exclusion of various emission sources and certain modeling decisions have been questioned, the HRAs include conservative assumptions of Project activities modeled in accordance with SJVAPCD, California Air Resources Board, and U.S. Environmental Protection Agency requirements. A technical memorandum explaining why the assumptions, modeling, and conclusions of the HRAs are valid is included in SREIR (October 2020) Appendix B-1. Multi-pathway exposure was not utilized in the multi-well HRA, nor were chronic and acute impacts considered, as approximately 99.9% of the risk associated with the multi-well scenario comes from diesel particulate matter and thus inhalation is the dominant pathway for exposure. As shown by the single-well HRAs, even with the inclusion of extensive production equipment, including engines, a cogeneration facility, several tanks, a flare, and additional equipment, both the acute and chronic (non-cancer) impacts are well below the SJVAPCD regulatory threshold.

Section 4.3, Air Quality also contains a thorough discussion of various reports addressing potential health effects due to proximity to oil and gas operations. As described in Section 4.3, the potential health effects from oil and gas operations is not new information and these potential impacts were incorporated into the analysis and mitigation measures in Section 4.3 in the 2015 FEIR. The studies do not suggest that new mitigation, beyond that included in Section 4.3, is necessary to *mitigate potential health impacts from the Project. However, the studies, particularly Tran et al. (2020) and Gonzalez et al. (2020), add to the general knowledge of oil and gas health effects, particularly in Kern County. Other studies that are based on oil and gas operations outside of California are less useful and their conclusions do not necessarily apply to California. As explained in the CCST Summary Report (July 2015), present-day hydraulic fracturing practice and geologic conditions in California differ from those in other states (CCST 2015b). Because California reservoirs are shallower and more permeable, wells tend to be shorter and near-vertical as opposed to horizontal. This means that wells in California take less time to drill, and drilling time is the main driver of health risk from Project activities because it produces the most emissions of toxic diesel particulate matter, which accounts for 99% of the health risk from the Project. Thus, any reports or studies that do not directly address California operations are less likely to support the link between health effects and oil and gas operations in Kern County.*

For these reasons, an alternative that requires a 2,500-foot setback from all oil and gas operations would not result in less significant air quality impacts. In fact, such an alternative may result in higher criteria pollutant and greenhouse gas emissions than would the Project due to the fact that more horizontal drilling may occur if such a setback were in place County-wide. A major contributor to Project emissions is drilling emissions, which are directly related to well depth. If a 2,500-foot setback were in place, a producer may need to drill further to reach a reservoir through horizontal drilling, as compared to the reservoir being reached by vertical drilling under the Project. For example, to reach a reservoir at a total vertical depth of 8,100 feet with a 2,500-foot setback, the well must descend vertically for a minimum of 7,000 feet to the "kick off point" for a gradual turn to horizontal. To reach the target, the borehole would extend for a total of 9,900 feet (total measured depth, i.e., vertical plus angled plus horizontal segments), representing 1,800 feet of additional footage drilled compared to 8,100 feet for a well drilled vertically to the same target, with correspondingly increased drilling time and emissions. Horizontal drilling not only requires longer drilling times, which increase emissions, but also tends to utilize higher horsepower drilling equipment, resulting in higher emissions than vertical drilling for an equivalent distance. As a result, where the reservoir does not directly underlie the relocated well, a 2,500-foot setback would require longer drilling time and corresponding increased emissions. Thus, a 2,500-foot setback alternative may result in significantly higher criteria pollutant and greenhouse gas emissions than would the Project.

An alternative that requires a 2,500-foot setback from all oil and gas activities would not result in less severe environmental noise impacts than would the Project. As described in Section 4.12.4, Noise, Impacts and Mitigation, Methodology of Impacts and Mitigation of the SREIR (October 2020), noise levels associated with oil and gas production activities were measured by Brown-Buntin Associates, Inc., at 18 locations throughout Kern County from January 7, 2015, to January 21, 2015 (Brown-Buntin 2015). For each activity, noise level measurements were taken in a minimum of four different directions from the activity to document the loudest direction of noise.

Project-related noise levels were calculated by Brown-Buntin Associates, Inc., using the SoundPLAN acoustic model. SoundPLAN utilizes measured spectral sound power levels to determine noise exposure from a noise source. Inputs to the model include noise source spectral sound power levels, topography, atmospheric conditions, ground absorption factors, shielding *from existing walls or buildings, noise source height, and receiver height. The modeling included the conservative assumption that the topography was flat. Using the SoundPLAN noise model, which is based on ISO 9613, is overly conservative on sites with a flat topography or steady downward slope from well pad to receiver. It is also important to recognize that, in scenarios where the topography is relatively flat or there is a steady slope away from a sound source located on a hill, these methods can over-predict noise by up to 6 decibels (dB), even where line-of-sight from the receiver location to the turbine hub is not broken. The model included the loudest observed noise measurement for each source as a basis for modeling potential Project-related noise exposure. The model included no shielding as a result of buildings or other structures that may be in the sound propagation path. These assumptions represent a highly conservative, worst-case assessment in regards to noise propagation from individual sources (Brown-Buntin 2015).*

For purposes of oil and gas development, noise impacts are considered significant if (1) they would result in a noise level greater than 65 dB or (2) if they would result in a substantial increase over existing ambient noise levels. An increase over ambient is considered substantial if it is greater than 5 dB where the existing ambient is less than 65 dB or if it is greater than 1 dB where the existing ambient is greater than 65 dB.

As explained under Impact 4.12-1 in the Chapter 4.12, Noise of the SREIR (October 2020), based on the conservative noise modeling assumptions, operational activities will not exceed the 65 dB standard at 210 feet and will not result in a greater than 5 dB increase over even the lowest measured ambient at 650 feet. A 2,500-foot setback is therefore unnecessary to reduce operational noise impacts to less than significant.

When using the highly conservative modeling assumptions, most construction activities are mitigated to less than 65 dB at much closer distances than 2,500 feet. Only large-scale exploratory drilling requires a larger setback of 3,270 feet. To ensure there are no increases over the 65 dB absolute standard or the 5 dB/1 dB incremental standard, applicants must comply with MM 4.12-1, which requires that either the applicant meet the screening distances based on the lowest measured ambient level in the County or prepare an additional noise reduction report and incorporate attenuation measures if necessary to meet the applicable noise standard. Therefore, a 2,500-foot setback would not achieve greater reductions than would the mitigated Project.

Section 4.12, Noise also contains a thorough discussion of various reports addressing the noise effects of unconventional oil and gas development in non-California jurisdictions). Studies that are based on oil and gas operations outside of California are less useful and their conclusions do not necessarily apply to California. As explained in the CCST Summary Report (July 2015), present-day hydraulic fracturing practice and geologic conditions in California differ from those in other states. Because California reservoirs are shallower and more permeable, wells tend to be shorter and near-vertical as opposed to horizontal. This means that wells in California take less time to construct. As illustrated in Chapter 4.12, construction activities are the main sources of noise effects from oil and gas activities. Because the construction period is much shorter for California wells and because hydraulic fracturing is used less frequently, reports or studies that do not directly address California operations are less likely to accurately represent California noise effects.

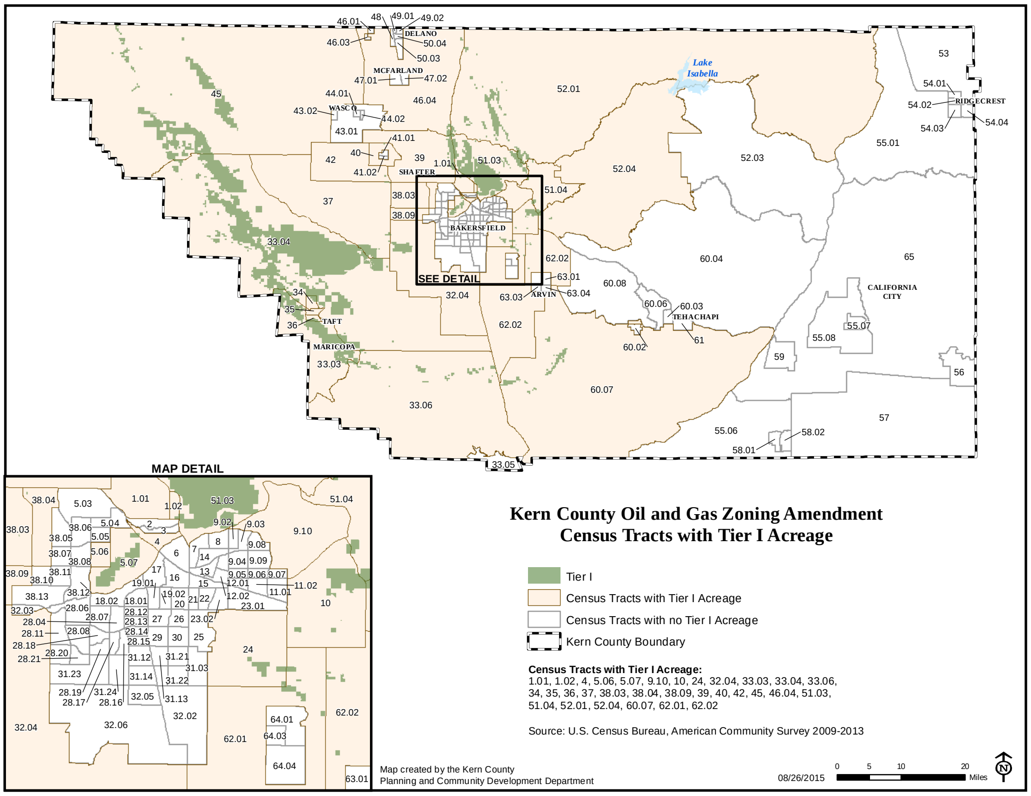
For these reasons, an alternative that requires a 2,500 foot setback from all oil and gas operations would not result in less significant noise impacts. In fact, such an alternative may result in greater noise levels due to the fact that more horizontal drilling occurring over a longer time period may be necessary if such a setback were in place County-wide.

Like the Project, Alternative 7 would establish a new "Oil and Gas Conformity Review" ministerial permit procedure to ensure compliance with the updated development standards and conditions and would provide for ongoing tracking and compliance monitoring. Alternative 7 also is expected to have impacts similar to those of the Project, with respect to aesthetic and visual resources, agricultural and forest resources, biological resources, cultural and paleontological resources, geology and soils, hazards and hazardous materials, hydrology and water quality, land use and planning, mineral resources, population and housing, public services, recreation, transportation and traffic, and utilities and service systems.

One contention of advocates of the 2,500-Foot Setback Alternative is that a 2,500-foot setback would protect communities that are disproportionately burdened by environmental impacts—specifically, poorer communities and communities of color. Economic or social factors may contribute to the environmental impacts of a project or may contribute to determinations of the significance of impacts; however, they do not constitute impacts in themselves. CEQA Guidelines §§ 15064(e), 15131(b), 15382; Bakersfield Citizens for Local Control v. City of Bakersfield (2004) 124 Cal. App. 4th 1184, 1213. Although not required by CEQA, for informational purposes only, an analysis was conducted of the Kern County census tract 5-year American Community Survey (ACS) demographic and poverty data for the period to provide additional context regarding the location of Tier 1 oil and gas activity areas and County demographic and poverty rates. This analysis has been further updated to reflect new data from ACS prepared for 2018.

The vast majority—90%—of wells under the Ordinance are projected to be located in Tier 1 lands. The total Tier 1 acreage in each census tract was identified to analyze the demographics and poverty data for the locations where the significant majority of all future oil and gas activity will occur. Of the 151 census tracts in Kern County, 31 contain Tier 1 acreage, and 120 contain no Tier 1 acreage. Figure 6-1 shows the location of each census tract and Tier 1 acreage in the County.

Figure 6-1 Kern County Oil and Gas Zoning Amendment Census Tracts with Tier 1 Acreage



Path: I:\GIS\projects\oil_gas\maps\census_tracts_with_tier1.mxd

Tables 6-1 and 6-2 summarize the ACS population, demographic, and poverty data for the County as a whole, the 120 census tracts that contain no Tier 1 acreage (the "non-Tier 1 tracts"), and the 31 census tracts that contain Tier 1 acreage (the "Tier 1 tracts"). The County's 151 census tracts (including Non-Jurisdictional areas such as incorporated cities and land owned by state and federal agencies) include about 5,223,940 acres. The non-Tier 1 tracts include about 1,926,762 acres, and the Tier 1 tracts include 3,297,178 acres. As discussed in the 2015 FEIR, the total amount of Tier 1 acreage in the County is 206,856 acres. Tier 1 areas overlay about 4% of the County and 6% of the Tier 1 tracts.

Table 6-1: Kern County Census Tract Demographics

	2015 ACS Data			2018 ACS Data		
	Kern County	Non-Tier 1 Census Tracts	Tier 1 Census Tracts	Kern County	Non-Tier 1 Census Tracts	Tier 1 Census Tracts
Total Population	848,204	661,039	187,165	883,053	685,717	197,336
Percent of Total County Population	100%	78%	22%	100%	77.7%	22.3%
Percent Hispanic or Latino (of any race)	49.8%	52.1%	41.7%	52.8%	55.3%	44.0%
Percent White	37.9%	34.5%	50.0%	34.8%	31.5%	46.1%
Percent Black or African American	5.3%	6.1%	2.4%	5.1%	6.1%	1.8%
Percent American Indian and Alaska Native	0.7%	0.7%	0.6%	0.5%	0.4%	0.6%
Percent Asian	4.1%	4.3%	3.4%	4.6%	4.5%	4.9%
Percent Pacific Islander, Other Race, Two or More Races	2.2%	2.3%	1.9%	2.3%	2.3%	2.6%

Key:
ACS = American Community Survey

While the County has become increasingly diverse, the latest ACS data do not alter the conclusions from 2015 regarding the populations most impacted by Project activities. According to the ACS 2018 data, the County (including Non-Jurisdictional areas) had an average population of 883,053 people. About 685,717 residents, or 77.65%, of the total County population, were located in non-Tier 1 tracts and about 197,336 residents, or 22.34%, of the County population, were located in Tier 1 tracts. Table 6-1 also shows that the average percentage of the population identified in the ACS data as Hispanic or Latino (of any race), Black or African American, American Indian and Alaska Native, Asian, Pacific islander, other race, or two or more races is lower in Tier 1 tracts than in the County as a whole and in non-Tier 1 census tracts. The percentage of the population identified as White is higher in Tier 1 tracts—where the majority of oil and gas development will occur—than in the County as a whole and in the non-Tier 1 tracts.

The ACS data also provide poverty level information for an average of 851,826 individuals in 2018. As shown in Table 6-2, the percentage of the population below the poverty level in Tier 1 tracts (17.3%) is lower than in the County as a whole and in non-Tier 1 census tracts (22% to 23.3%).

Table 6-2: Kern County Census Tracts Poverty Levels

	2015 ACS Data			2018 ACS Data		
	Kern County	Non-Tier 1 Census Tracts	Tier 1 Census Tracts	Kern County	Non-Tier 1 Census Tracts	Tier 1 Census Tracts
Population for which Poverty Level Was Determined	814,695	635,065	179,630	851,826	660,668	191,158
Total Population below Poverty Level	186,811	156,751	30,060	187,232	153,988	33,244
Percent Total Population below Poverty Level	22.9%	24.7%	16.7%	22.0%	23.3%	17.4%

Key:
ACS = American Community Survey

The vast majority of wells proposed under the Ordinance are therefore anticipated to be located in areas with a higher proportion of white residents and a lower poverty rate than the County as a whole and non-Tier 1 lands. These results indicate that the activities allowed under the Ordinance, the vast majority of which occur in Tier 1 areas, do not appear to be spatially distributed in a manner that disproportionately focuses future oil and gas environmental impacts on sensitive populations. Even if social and economic impacts were cognizable under CEQA, a 2,500-foot setback would not significantly reduce the Project's effects.

Alternative 7's Relationship to the Project Objectives

Alternative 7 would achieve some of the Project objectives, but to the same extent as the Project. Alternative 7 would update the County's Zoning Code in a manner similar to the Project, though it would require that new wells be set back at 2,500 feet from sensitive receptors. Alternative 7 would also encourage ongoing and increased economic development by the oil and gas industry in a manner consistent with the Project objectives, though not to the same extent as the Project. Alternative 7 would also help reduce California's dependence on foreign sources of energy and would accommodate foreseeable need in appropriate locations, but only to the extent more oil and gas can be produced through increased horizontal and directional drilling techniques than would occur under Project and the "No Project" scenario. Alternative 7 would also ensure the protection of environmental resources through the development and implementation of industry-wide best practices, performance standards, and mitigation measures, but it would have greater overall environmental effects in some impact categories than would the Project, as discussed above.

Alternative 7 would streamline and provide more certainty to the County's oil and gas regulations and environmental review processes, though not to the same extent as the Project, as it would impose new regulatory barriers to new wells that in some cases could prevent a mineral rights holder from exercising those rights. Specifically, the 2,500-foot setback required by Alternative 7 could prevent some mineral rights holders from exercising those rights if, for example, geologic features and constraints prevent the use of horizontal drilling techniques to reach mineral resources from a location beyond the setback boundary. Many oil and gas reservoirs in California *are faulted and discontinuous laterally with stack pay potential and are thus not conducive to a horizontal well geometry. In those circumstances, this alternative's setback requirement could extinguish a producer's ability to access its mineral resources.*

Land use regulations that provide "no adequate means of protection or substitute for their right to extract oil from the property" are a taking of private property requiring the payment of just compensation. (Braly v. Board of Fire Commissioners of City of Los Angeles [1958] 157 Cal.App.2d 608, 616.) While localities can restrict oil drilling by means of reasonable zoning regulations, unreasonable restrictions on oil operations are not proper land use regulations, especially where property owners or lessees have invested in existing infrastructure and have acquired vested rights to continue drilling operations. Adoption of these regulations would subject the County to takings liability.

Land use restrictions must be reasonable in light of the need for these regulations to address public safety issues. As established by a US Supreme Court case in 1922, "while property may be regulated to a certain extent, ***if regulation goes too far*** *it will be recognized as a taking." (Pa. Coal Co. v. Mahon [1922] 260 U.S. 393, 415, emphasis added.) The California Supreme Court has also found that "[w]hile the police power is very broad in concept, it is not without restrictions in relation to the taking or damaging of property" (House v. Los Angeles County Flood Control Dist. [1944] 25 Cal.2d 384.) "When it passes* ***beyond proper bounds in its invasion of property rights****, it in effect comes within the purview of the law of eminent domain and its exercise requires compensation" (Ibid., emphasis added).*

A taking may occur where a regulation has deprived a parcel of property of substantially all economic value (Lucas v. South Carolina Coastal Council [1992] 505 U.S. 1003, 112 S. Ct. 2886, 120 L. Ed. 2d 798). For mineral owners who have severed their mineral rights from the overlying surface rights, a complete take of all property value can occur where the mineral right owner is no longer allowed to access the oil within its mineral estate. Further, excess restrictions can preclude any further development of the resource.

Even if a property retains substantial economic value, an unreasonable regulation can be considered a "take" based on consideration of several factors, most notably whether the regulation interferes with the distinct investment-backed expectations of the property owners. (Penn Central Transportation Company v. City of New York [1978] 438 U.S. 104, 98 S. Ct. 2646, 57 L. Ed. 2d 631). And while such regulations would require an ad hoc, factual adjudication to determine if they constitute a taking, the County may still be liable for a temporary taking during the time that this regulation is enforced prior to an adjudication (First Lutheran Church v. Los Angeles County [1987] 482 U.S. 304, 318. [96 L.Ed.2d 250, 107 S.Ct. 2378). As the Project is intended to streamline regulations and allow for the ministerial approval of new wells, the excessive restriction on new wells will cause an immediate injury to operators and mineral right owners, subjecting the County to temporary takings liability for areas where the restriction has substantially interfered with a property owner's distinct investment-backed expectations to continue oil extraction.

Reasonable regulations may be imposed on a person's right to drill for oil on his or her property or in the mineral lease, in order to avoid a nuisance. "The owner of a property right to drill for *and extract oil in a proven field acquired under a permit, may not constitutionally be deprived thereof without payment of just compensation except upon a showing that its exercise constitutes a nuisance" (Trans-Oceanic Oil Corp v. Santa Barbara [1948] 85 Cal.App.2d 776, 789). However, Alternative 7 would apply throughout the County regardless of whether a specific operation has been found to constitute a nuisance. The County has the authority to abate a public nuisance without needing to impose overly broad provisions that would apply across-the-board to a large number of situations that are not causing a public nuisance.*

Excessive setback conditions or other restrictions precluding drilling would subject the County to serious allegations of takings liability under California law, along with the risk of protracted litigation. "Under the law of this state the landowner has a property right in oil and gas beneath the surface, not in the nature of an absolute title to the oil and gas in place, but as an exclusive right to drill upon his property for these substances" (Bernstein v. Bush [1947] 29 Cal.2d 773, 778). "This is a right which is 'as much entitled to protection as the property itself, and the undue restriction of the use thereof is as much a taking for constitutional purposes as appropriating or destroying it'" (Ibid., quoting People v. Associated Oil Co. [1930] 211 Cal. 93, 99-100 and cases cited). According to a 2018 study, prepared by the Western States Petroleum Association, a 2,500 foot setback from sensitive land uses in Kern County would impact 3,094 existing active and in-progress wells in Kern County, which collectively produced a total of 4,967,323 barrels of oil in 2017 (Schwartz 2019). Infringement on operators' abilities to produce from those wells would expose the County to liability and is not a feasible approach. Separately, such interference would run counter to the Project objectives. Even where such setbacks are limited to future wells, an operator and mineral right owner has a right to access these mineral resources that may not be unduly restricted. While other jurisdictions may have adopted varying distances of setback, excessive distances, such as in Ventura County, are subject to litigation and their legal viability is questionable, without supporting environmental and science based public review and findings of fact.

Mineral rights owners and their operators also have a right under the diminishing asset doctrine to expand their extractive operations to use the entire parcel of land that was intended. "The very nature and use of an extractive business contemplates the continuance of such use of the entire parcel of land as a whole, without limitation or restriction to the immediate area excavated at the time the ordinance was passed" (Hansen Bros. Enters. v. Bd. of Supervisors [1996] 12 Cal.4th 533, 553). Any artificial restriction on new wells must account for the legal rights of operators to continue their operations. Even if there are some areas within the County that can accommodate setback restrictions without a loss in production, a blanket restriction would still be legally infeasible. If the County is held to have caused a taking by preventing the installation of even one well, the County would face a significant financial liability. Given the large number of established fields and oil activity within the County, even a small percentage of affected areas could result in large liabilities for the County.

Even if the Project's objectives would allow for undue restrictions on oil and gas operations, there is no reasonable basis to avoid the risk of takings liability. A savings clause would not prevent a court from imposing a judgment on the County that it is liable for just compensation for the taking of property rights. In the litigation over the Measure Z initiative adopted by the voters of Monterey

County, the trial court rejected arguments that a savings clause in the initiative excused the County from liability for provisions preventing operators from drilling new wells to access their mineral rights (Final Statement of Decision in Chevron U.S.A. Inc. v. County of Monterey, Monterey Sup. Ct., Case No. 16-CV-003978 [filed Jan. 25, 2018) at p. 41]. The Court distinguished situations where a savings clause was applied to ordinances allowing a county to impose exactions as a condition of subdivision map and plan approvals:

> *"There, a taking would only occur if and when the County imposed one or more easements as a condition of project approval. . . . Here, any taking would occur upon Measure Z's taking effect. Section 6(C) could theoretically reduce or eliminate that taking, but only after the fact, and, as discussed ante, its procedure is sufficiently, convoluted that it risks arbitrary and discriminatory application. Additionally, it is so lengthy that it would impose a significant financial burden on property owners in the interim, possibly up to and including a total loss of all economic value of the relevant property before the administrative process — and the nearly certain ensuing litigation — is complete."*

Here, as in the Measure Z litigation, any undue restrictions on oil and gas operations would take effect immediately, precluding operators from drilling the wells needed to access mineral rights that they previously had the right to extract from. Even if there were procedures put into place to avoid or allow for variances from these restrictions, those procedures would not negate the immediate impact to property rights caused by the enactment of the restrictions, even assuming that such procedures would be constitutionally adequate. Thus, any savings clauses or other administrative process would be inadequate to reduce the risk of takings liability, including damages from the temporary denial of property rights.

The amortization process has been used as a means to avoid paying just compensation for the removal of billboards or other transient objects. An amortization process would be unworkable, however, for longstanding and highly interconnected facilities such as an oil field, which requires the continual investment of capital and whose remaining useful life is continually being extended by new technology. While the City of Culver City may be considering relying upon an amortization study to prevent further oil operations within the small subset of the Inglewood oil field that is within its jurisdiction, the City has not yet taken any action, and any such action would almost certainly be subject to legal challenge. There is significant legal uncertainty in the applicability of amortization to even a small portion of an oilfield as in Culver City. Even if Culver City proceeds with an amortization process, the remaining life of the field must serve as a basis for the amortization process. Further, an amortization for a small portion of a field operated by one operator cannot be feasibly extrapolated to a large, oil-producing county like Kern County.

6.8 Comparative Impacts of Project to All Alternatives

A summary of the comparative impacts of the Project to all of the alternatives analyzed in this EIR is set forth in Table 6-1.

Table 6-1: Summary of Comparison of Alternative Impacts

	Project Summary of Impacts	**Alternative 1** No Project	**Alternative 2** CUP Alternative	**Alternative 3** Reduced Ground Disturbance Alternative	**Alternative 4** No Hydraulic Fracturing Alternative	**Alternative 5** Low-Emission EOR Technology Alternative	**Alternative 6** Recycled Water Alternative	***Alternative 7 Setback Alternative***
Aesthetics and Visual Resource	Significant and Unavoidable	Greater than Project	Same as Project	Less than Project	Same as Project	Same as Project	Greater than Project	*Same as Project*
Agricultural and Forest Resources	Significant and Unavoidable	Greater than Project	Same as Project	Less than Project	Same as Project	Same as Project	Same as Project	*Same as Project*
Air Quality	Significant and Unavoidable	Greater than Project	Greater than Project	Greater than Project	Greater as Project	Less than Project	Greater than Project	*Greater than Project*
Biological Resources	Significant and Unavoidable	Greater than Project	Greater than Project	Less than Project	Same as Project	Same as Project	Greater than Project	*Same as Project*
Cultural and Paleontological Resources	Significant and Unavoidable	Greater than Project	Same as Project	Less than Project	Same as Project	Same as Project	Greater than Project	*Same as Project*
Geology and Soils	Less than Significant	Greater than Project	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	*Same as Project*
Greenhouse Gas Emissions and Global Climate Change	Significant and Unavoidable	Greater than Project	Greater than Project	Greater than Project	Greater than Project	Less than Project	Greater than Project	*Greater than Project*
Hazards and Hazardous Materials/Public Health Risks	Less than Significant	Greater than Project	Greater than Project	Same as Project	Less than Project	Same as Project	Same as Project	*Same as Project*
Hydrology and Water Quality	Significant and Unavoidable	Greater than Project	Greater than Project	Same as Project	Less than Project	Same as Project	Less than Project	*Same as Project*
Land Use and Planning	Less than Significant	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	*Same as Project*
Mineral Resources	Less than Significant	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	*Same as Project*

Table 6-1: Summary of Comparison of Alternative Impacts

	Project Summary of Impacts	**Alternative 1** No Project	**Alternative 2** CUP Alternative	**Alternative 3** Reduced Ground Disturbance Alternative	**Alternative 4** No Hydraulic Fracturing Alternative	**Alternative 5** Low-Emission EOR Technology Alternative	**Alternative 6** Recycled Water Alternative	***Alternative 7 Setback Alternative***
Noise	Significant and Unavoidable	Greater than Project	Same as Project	Same as Project	Same as Project	Same as Project	Greater than Project	*Greater than Project*
Population and Housing	Less than Significant	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	*Same as Project*
Public Services	Less than Significant	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	*Same as Project*
Recreation	Less than Significant	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	Same as Project	*Same as Project*
Transportation and Traffic	Less than Significant	Greater than Project	Greater than Project	Greater than Project	Same as Project	Less than Project	Same as Project	*Same as Project*
Utilities and Service Systems	Significant and Unavoidable	Greater than Project	Same as Project	Same as Project	Same as Project	Same as Project	Less than Project	*Same as Project*

6.9 Environmentally Superior Alternative

Identification of an environmentally superior alternative is required under CEQA (Cal. Code Regs. Section 15126.6(e)(2)).

As compared to the Project, Alternative 1, the No Project Alternative, would have greater impacts than the Project in most categories. Alternative 2, the CUP Alternative, would slightly reduce the Project's aesthetic impacts, but would also generate greater in environmental effects than the Project is multiple impact categories. As compared to the Project, Alternative 3, the Reduced Ground Disturbance Alternative, would have less impacts to aesthetic resources, agricultural resources, cultural resources, and biological resources, but these environmental benefits would be offset by greater environmental impacts related to air quality, greenhouse gas emissions, noise, and traffic. Alternative 4, the No Hydraulic Fracturing Alternative, would have less water quality and hazards impacts than the Project, but would have greater impacts related to air quality and greenhouse gas emission than the Project. As compared to the Project, Alternative 6, the Recycled Water Alternative, would have less hydrology and water quality impacts, and less utilities and service system impacts, than the Project, but would have greater impacts related to aesthetics, air quality, biological resources, cultural resources, greenhouse gas emissions, and noise. *As compared to the Project, Alternative 7, the 2,500-Foot Setback Alternative, would have greater air quality, greenhouse gas, and noise impacts to the extent that it would result in more incidents of horizontal drilling operations.*

The environmentally superior alternative is Alternative 5, the Low-Emission EOR Technology Alternative. Compared to the Project, Alternative 5 would have less environmental effects related to air quality, greenhouse gases, and transportation and traffic. Moreover, Alternative 5 would not result in any environmental impacts that are greater than those of the Project.

This assessment of the environmental superior alternative is consistent with the assessment set forth in 2015 FEIR Chapter 6, Alternatives, and it is not changed or materially altered by the supplemental analysis set forth in Chapter 4 of this SREIR *(October 2020)*.

Chapter 7

Response to Comments

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Chapter 7

Response to Comments

This chapter is reserved for, and will be included in, the Final SREIR.

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Chapter 8

Organizations and Persons Consulted

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Chapter 8
Organizations and Persons Consulted

8.1 Federal

Edwards Air Force Base

U.S. Air Force

U.S. Army

U.S. Bureau of Land Management

U.S. Department of Agriculture, Natural Resource Conservation Service

U.S. Environmental Protection Agency Region IX

U.S. Fish and Wildlife Service

U.S. Marine Corps

8.2 State of California

California Air Resources Control Board

California Department of Conservation

California Department of Conservation, Geologic Energy Management Division

California Department of Fish and Wildlife

California Department of Public Health

California Energy Commission

California Highway Patrol

California Natural Resources Agency

California Regional Water Quality Control Board, Lahontan Region

California State Clearinghouse

California State University Bakersfield

San Joaquin Valley Air Pollution Control District

8.3 Regional and Local

Antelope Valley-East Kern Water Agency

California City Planning Department

City of Arvin

City of Bakersfield Planning Department

City of Bakersfield Public Works Department

City of Bakersfield, Police Department

City of Delano Planning Department

City of Maricopa

City of McFarland

City of Ridgecrest

City of Shafter

City of Taft

City of Tehachapi

City of Wasco

East Kern Air Pollution Control District

Inyo County Planning Department

Kern Council of Governments

Kern County Public Works

Kern County Administrative Officer

Kern County Agriculture Department

Kern County Environmental Health Services Department

Kern County Fire Department

Kern County Library, Beale Branch

Kern County Planning and Natural Resources Department

Kern County Sheriff's Department

Kern County Water Agency

Pacific Gas & Electric Company

San Luis Obispo County Planning Department

Santa Barbara County Resource Management Department

South San Joaquin Valley Archaeological Information Center

Southern California Edison

State Office of Historical Preservation

Tejon Native American Tribe

Tulare County Planning and Development Department

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Chapter 9

List of Preparers

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Chapter 9
List of Preparers

9.1 Lead Agency

Kern County Planning and Natural Resources Department

Ms. Lorelei Oviatt, AICP, Planning Director

Mr. Craig Murphy, Assistant Director

Ms. Cindi Hoover, Planner III Advanced Planning Division

Mr. Louis Ramirez, Planner I Advanced Planning Division

9.2 Technical Assistance

Ecology and Environment, Inc.

Mr. Dave Albers, PE, Project Director

Dr. Michael Smith, Project Manager

Ms. Manique Talaia-Murray, *Deputy Project Manager and* Groundwater

Mr. James Thornton, Project Manager *for the August 2020 SREIR*

Ms. Silva Yanez, Air Quality

Mr. Fernando Guzman, Agriculture

Ms. Erin Lynch, Hydrology

Mr. Kevin Keller, Noise

Ms. Catherine Billor, Water Resources

Dr. Amy Cook, Technical Editor

Mr. Marc Koopman, GIS

Ms. Amber Santilli, Document Formatting/Production

Environmental Compliance Solutions, Inc.

Ms. Erin Sheehy, LEED AP

A full list of all prepares of the 2015 FEIR provided in Volume 3 – Chapter 9.0 List of Preparers.

Chapter 10
Bibliography

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Chapter 10
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3.0 Project Description

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Chapter 11

Acronyms, Abbreviations, and Glossary

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Chapter 11
Acronyms, Abbreviations, and Glossary

11.1 Acronyms and Abbreviations

°F	Degrees Fahrenheit
µS/cm	MicroSiemens per Centimeter
µg/m^3	Micrograms per Cubic Meter
A	Exclusive Agriculture (zoning district)
A-1	Limited Agriculture (zoning district)
AADT	Annual Average Daily Traffic
AB	Assembly Bill
ACBM	Asbestos-Containing Building Material
ACEC	Areas of Critical Environmental Concern
ADSA	Axial Dimensional Stimulation Area
AEWSD	Arvin-Edison Water Storage District
AF	Acre-Feet
AFB	Air Force Base
AFY	Acre-Feet per Year
AGL	Above Ground Level
AIR	Association of Irritated Residents
ALUCP	Airport Land Use Compatibility Plan
Amended Zoning Ordinance	all text changes to the Kern County Zoning Ordinances as proposed and analyzed in this Supplemental Recirculated Environmental Impact Report
AMSL	Above Mean Sea Level
ANSI	American National Standards Institute
ANSS	Advanced National Seismic System
AOF	Administrative Oil Field
AOR	Area of Review
APCD	Air Pollution Control District
APCO	Air Pollution Control Officer
API	American Petroleum Institute

Appellate Court	Fifth Appellate District of the California Court of Appeal
APSA	Aboveground Petroleum Storage Act
AQMD	Air Quality Management District
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATC	Authority to Construct
ATCM	Airborne Toxic Control Measure
AUC	Area Under the Curve
AWMP	Agricultural Water Management Plan
AWWA	American Water Works Association
B&B	Brown and Bryant Arvin facility
B&K	Bruel & Kjaer
B.P.	Before Present
BACT	Best Available Control Technology
BAU	Business-As-Usual
bbl	barrel
BFD	Bakersfield Fire Department
BFW	Base Freshwater Interface
BGEPA	Bald and Golden Eagle Protection Act
BGS	Below Ground Surface
bhp	Brake Horsepower
BLM	U.S. Department of the Interior, Bureau of Land Management
BLS	Bureau of Labor Statistics
BMP	Best Management Practice
BNLL	Blunt-Nosed Leopard Lizard
BOPE	Blowout Prevention Equipment
BPD	Bakersfield Police Department
BPS	Best Performance Standards
Bq/m^3	becquerels per cubic meter
BRM	Bedrock Mortar
BSK	BSK Associates
Btu	British thermal unit
BWSD	Belridge Water Storage District
C-1	Neighborhood Commercial
C&D	Construction and Demolition

C2ES	Center for Climate and Energy Solutions
C2VSim FG-Kern	C2VSim Fine Grid Beta Model
CAA	Clean Air Act
CAAQS	California Ambient Air Quality Standards
CADTSC	California Department of Toxic Substances Control
CAL FIRE	California Department of Forestry and Fire Protection
Cal/OSHA	California Occupational Safety and Health Administration
CalARP	California Accidental Release Prevention Program
CALEEMOD	California Emission Estimator Model
CalEPA	California Environmental Protection Agency
CALFIRE	California Department of Forestry and Fire Protection
CalGEM	California Geologic Energy Management Division
CalOES	California Office of Emergency Services
CalRecycle	California Department of Resources Recycling and Recovery
Caltrans	California Department of Transportation
CALVEG	Classification and Assessment with Landsat of Visible Ecological Groupings
CAPCOA	California Air Pollution Control Officers Association
CARB	California Air Resources Board
CASGEM	California Statewide Groundwater Elevation Monitoring
CBC	California Building Code
CBE	Communities for a Better Environment
CCAA	California Clean Air Act
CCAP	Climate Change Action Plan
CCR	California Code of Regulations
CCST	California Council on Science and Technology
CDFG	California Department of Fish and Game
CDFW	California Department of Fish and Wildlife
CDFW-OSPR	California Department of Fish and Wildlife-Office of Spill Prevention and Response
CDPH	California Department of Public Health
CEC	California Energy Commission
CEDD	California Employment Development Department
CEHP	California Essential Habitat Connectivity Project
CEPAM	California Emissions Projection Analysis Model

CEQA	California Environmental Quality Act
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act/Superfund Amendments And Reauthorization Act
CERS	California Environmental Reporting System
CESA	California Endangered Species Act
CFC	Chlorofluorocarbon
CFGC	California Fish and Game Code
CFR	Code of Federal Regulations
cfs	Cubic Feet per Second
CGS	California Geological Survey
CH	Highway Commercial (zoning district)
CH_4	Methane
CHL	California Historical Landmark
CHNA	Community Health Needs Assessment
CHP	California Highway Patrol
CHRIS	California Historical Resources Information System
CIP	Capital Improvement Program
CIPA	California Independent Petroleum Association
CMP	Congestion Management Program
CNDDB	California Department of Fish and Wildlife Natural Diversity Database
CNEL	Community Noise Equivalent Level
CNPS	California Native Plant Society
CNRA	California Natural Resources Agency
CO	Commercial Office (zoning district)
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO2e (MtCO2e)	Carbon Dioxide Equivalent
COG	Council of Governments
COHb	Carboxyhemoglobin
County	Kern County, California
CPNM	Carrizo Plain National Monument
CPUC	California Public Utilities Commission
CRC	California Resources Corporation
CREED	Citizens for Responsible Equitable Environmental Development

CRHR	California Register of Historic Resources
CRPR	California Rare Plant Rank
CRWQCB	California Regional Water Quality Board
CSA	County Service Area
CSC	California Department of Fish and Wildlife Species of Special Concern
CSLC	California State Lands Commission
CT	California State Threatened
CTR	California Toxics Rule
CUP	Conditional Use Permit
CUPA	Certified Unified Program Agencies
CVC	California Vehicle Code
CVFPB	Central Valley Flood Protection Board
CVP	Central Valley Project
CVRWQCB	Central Valley Regional Water Quality Control Board
CWA	Clean Water Act
CWC	California Water Code
CWD	Cawelo Water District
CWHR	California Wildlife Habitat Relationships
DAU	Detailed Analysis Unit
dB	Decibel
dBA	A-weighted Sound Level Measurement
DBCP	1,2-dibromo-3-chloropropane
DBH	Diameter at Breast Height
DCR	Delivery Capability Report
DEIR	Draft Environmental Impact Report
DHS	Department of Homeland Security
DI	Drilling Island
DMC	Development Mitigation Contracts
DNL	Day-Night Level
DOC	Department of Conservation
DOD	U.S. Department of Defense
DOF	Department of Finance
DOGGR	(California) Department of Conservation Division of Oil, Gas, and Geothermal Resources

DPM	Diesel Particulate Matter
DPR	Department of Pesticide Regulation
DRR	Delivery Reliability Reports
DSREIR	Draft Supplemental Recirculated Environmental Impact Report
DTSC	California Department of Toxic Substances Control
DWR	Department of Water Resources
E	Estate (zoning district)
E & E	Ecology and Environment, Inc.
E&P	Exploration and Production
ECC	Emergency Communications Center
ECDMS	Energy Consumption Data Management System
ECP	Eagle Conservation Plan; *also* Emissions Control Plan
EDC	Endocrine Disruptor Chemicals
EHHCP	Elk Hills Habitat Conservation Plan
EHOF	Elk Hills Oil Field
EIR	Environmental Impact Report
EIS	Environmental Impact Statement
EMS	Kern County Emergency Medical Services Division
EO	Executive Order
EOA	Exclusive Operating Area
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
ERC	Environmental Review Committee
ESA	Endangered Species Act
ESAL	Equivalent Single-Axle Load
eTRIP	Employer-based Trips Reduction
EWMA	Eastside Water Management Area
FAA	Federal Aviation Administration
FAR	Federal Aviation Regulations
Farmland	Prime Farmland, Farmland of Statewide Importance, and Unique Farmland
FC	Federal Candidate
FE	Federal Listed as Endangered
FEIR	Final Environmental Impact Report

FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FHWA	Federal Highway Administration
FIFRA	Federal Insecticide, Fungicide, and Rodenticide Act
FIRM	Federal Insurance Rate Map
FLPMA	Federal Land Policy and Management Act
FMCSA	Federal Motor Carrier Safety Administration
FMMP	Farmland Mapping and Monitoring Program
FP	State Fully Protected
FPP	Floodplain Primary (zoning district)
FPPA	Farmland Protection Policy Act
FPS	Floodplain Secondary
FRA	Federal Railroad Administration
FRP	Facility Response Plan
FSREIR	Final Supplemental Recirculated Environmental Impact Report
FSZ	Farmland Security Zone
FT	Federal Listed as Threatened
FTA	Federal Transit Administration
FTIP	Federal Transportation Improvement Program
FY	Fiscal Year
GAMA	Groundwater Ambient Monitoring and Assessment
GAMAQI	Guide for Assessing the Mitigation Air Quality Impacts
GHG	Greenhouse Gas
GHS	United Nations Globally Harmonized System of Classification and Labeling of Chemicals
GIS	Geographic Information System
GMA	Groundwater Management Agency
GPS	Global Positioning System
GSA	Groundwater Sustainability Agency
GSP	Groundwater Sustainability Plan
GWP	Global Warming Potential
H_2S	Hydrogen Sulfide
HABS	Historic American Buildings Survey
HAER	Historic American Engineering Record

HAP	Hazardous Air Pollutant
HARP2	Hotspots Analysis and Reporting Program, Version 2
HazMat	Hazardous Materials
HCA	High Consequence Areas
HCD	California Department of Housing and Community Development
HCP	Habitat Conservation Plan
HFC	Hydrofluorocarbon
HHWE	Household Hazardous Waste Element
HI	Hazard Index
HMBP	Hazardous Materials Business Plan
HMIS	Hazardous Materials Inventory Statement
HMMP/HMIS	California Uniform Fire Code Hazardous Materials Management Plans and Hazardous Materials Inventory Statement
HMRRP	Hazardous Materials Release Response Plan and Inventory Program
HMSP	Hazardous Materials Safety Permit
HMTA	Hazardous Material Transportation Act
HMWD	Henry Miller Water District
HOV	High-Occupancy Vehicle
HRA	Health Risk Assessment
HRRS	Health-Risk Reduction Strategy
HSM	Habitat Suitability Model
HSWA	Associated Hazardous and Solid Waste Amendments
I-5	Interstate 5
IBC	International Building Code
ICC	International Code Council
ICF	ICF International, Inc.
ICS	Incident Management System
ID	Irrigation District
ILRP	Irrigated Lands Regulatory Program
IOPA	Independent Oil Producers Association
InSAR	Interferometer Synthetic Aperture Radar
IRWMP	Integrated Regional Water Management Plan
IS	Initial Study
ISR	Indirect Source Rule

ITE	Institute of Transportation Engineers
ITP	Incidental Take Permit
ITS	Intelligent Transportation Systems
IWMB	Integrated Waste Management Board
KCEH	Kern County Environmental Health Division
KCFD	Kern County Fire Department
KCGP	Kern County General Plan
KCPCDD	Kern County Planning and Community Development Department
KCPNR	Kern County Planning and Natural Resources Department
KCS	Kern County Subbasin
KCSOS	Kern County Superintendent of Schools
KCWA	Kern County Water Agency
KCWMD	Kern County Waste Management Department
KEDC	Kern Economic Development Corporation
Kennedy/Jenks	Kennedy/Jenks Consultants
KGA	Kern Groundwater Authority
KGAGSP	Kern Groundwater Authority Groundwater Sustainability Plan
km	*kilometer*
KNWR	Kern National Wildlife Refuge
KOP	Key Observation Point
KRT	Kern Regional Transit
KSA	Kern Sanitation Authority
KTWD	Kern-Tulare Water District
kV	Kilovolt
KWB	Kern Water Bank
KWBA	Kern Water Bank Authority
KWBHCP	Kern Water Bank Habitat Conservation Plan
Kwh	Kilowatt Hours
lb/MMBtu	pounds per million metric British thermal unit
LBNL	Lawrence Berkeley National Laboratory
LCFS	Low Carbon Fuel Standard
LDA	Light Duty Autos
LDAR	Leak Detection and Repair

Ldn	Average Day-Night Level
Leq	Equivalent Sound Pressure Level
LEV	Low Emission Vehicle
LHCP	Lokern Habitat Conservation Plan
LHWD	Lost Hills Water District
Lmax	Maximum Noise Level
LOS	Level of Service
LS	Length Slope
M-1	Light Industrial (zoning district)
M-2	Medium Industrial (zoning district)
M-3	Heavy Industrial (zoning district)
M&I	Municipal and Industrial
MAOP	Maximum Allowable Operating Pressure
MASP	Maximum Allowable Surface Injection Pressure
MBGP	Metropolitan Bakersfield General Plan
MBHCP	Metropolitan Bakersfield Habitat Conservation Plan
MBTA	Migratory Bird Treaty Act
MCF	Million Cubic Feet
MCL	Maximum Contaminant Level
MDAB	Mojave Desert Air Basin
MEI	Maximally Exposed Individual
mg/L	Milligrams per Liter
MMBtu	One Million Metric British Thermal Units
MMBtu/hr	Million Metric British Thermal Units per Hour
MMRP	Mitigation, Monitoring, and Reporting Program
MM	mitigation measure
MMS	Mineral Management Service
MOA	Memorandum of Agreement
MOU	Memorandum of Understanding
MP	Mobile Home Park (zoning district)
mph	Miles Per Hour
MPO	Metropolitan Planning Organization
<u>MRP</u>	*<u>Monitoring and Reporting Program</u>*
MRR	Mandatory Reporting Regulation
MRZ	Mineral Resource Zone

MS4 NPDES permit	Municipal Separate Storm Sewer System (MS4) NPDES Permit
MSDS	Material Safety Data Sheet
MSHCP	Multiple Species Habitat Conservation Plan
MSL	Mean Sea Level
$MtCO_2e$	Million Metric Tons of Carbon Dioxide Equivalent
MUN	Municipal
MW	Megawatt
N_2O	Nitrous Oxide
NAAQS	National Ambient Air Quality Standards
NAHC	California Native American Heritage Commission
NAS	National Academy of Sciences
NASS	United States Department of Agriculture, National Agricultural Statistics Service
NCCP	Natural Community Conservation Plan
NCP	National Oil and Hazardous Substance Pollution Contingency Plan
NDFE	Non-Disposal Facility Element
NEC	No Exposure Certification
NEES	Network For Earthquake Engineering Simulation
NEHRP	National Earthquake Hazards Reduction Program
NEPA	National Environmental Policy Act
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NFIP	National Flood Insurance Program
NH_3	Ammonia
NHD	National Hydrology Dataset
NHPA	National Historic Preservation Act
NHTSA	National Highway Traffic and Safety Administration
NIMS	National Incident Management System
Ninth Circuit	Ninth Circuit Court of Appeals
NIST	National Institute of Standards and Technology
NKWSD	North Kern Water Storage District
NMFS	National Marine Fisheries Service
NO	Nitrogen Oxide
NO_2	Nitrogen Dioxide
NO_3	Nitrates

NOA	Naturally Occurring Asbestos
NOAA	National Oceanic and Atmospheric Administration
NOC	Notice of Completion
NOD	Notice of Determination
NOG	Non-Oil and Gas
NOI	Notice of Intent to Prepare an Environmental Impact Statement (CEQA); *also* Notice of Intent to Obtain Coverage under a General Permit (SWRCB); *also* Notice of Intention to Drill New Well (DOGGR) Notice of Intent
NONA	Notice of Non-Applicability
NOP	Notice of Preparation
NORM	Naturally Occurring Radioactive Material
NO_X	Oxides of Nitrogen
NPDES	National Pollutant Discharge Elimination System
NPL	National Priorities List
NPR	Naval Petroleum Reserves
NPS	National Park Service
NPDSE	National Pollutant Discharge Elimination System
NR	Natural Resource (zoning district)
NRC	National Response Center
NRCS	Natural Resources Conservation Service
NRDC	Natural Resources Defense Council
NRF	National Response Framework
NRHP	National Register of Historic Places
NRP	National Response Plan
NSF	National Science Foundation
NSPS	New Source Performance Standards
NSR	New Source Review
NTSA	National Trails System Act
NTU	Nephelometric Turbidity Units
NWI	National Wetlands Inventory
NWIS	National Water Information System
O_3	Ozone
OADP	Ozone Attainment Demonstration Plan

OEHHA	Office of Environmental Health Hazard Assessment
OG-ERA	Oil and Gas Emission Reduction Agreement
OHV	Off-Highway Vehicle
OMR	Office of Mine Reclamation
OPA	Oil Pollution Act
OPR	Governor's Office of Planning and Research
OPS	Office of Pipeline Safety
Ordinance	Kern County Zoning Ordinance
OS	Open Space (zoning district)
OSFM	Office of the State Fire Marshal
OSHA	Occupational Safety and Health Administration
P.L.	Public Law
PAH	Polycyclic Aromatic Hydrocarbon
PASER	Pavement Surface and Evaluation Rating System
Pb	Lead
PBSD	Performance-Based Seismic Design
PCDD	Planning and Community Development Department
pCi/g	Picocuries per gram
pCi/L	Picocuries per Liter
PCR	Petro Capital Resources
PCS	Pavement Condition Survey
PCT	Pacific Crest Trail
PE	Petroleum Extraction
PEER	Permit-Exempt Equipment Registration
PERC	Perchloroethylene
PERP	Portable Equipment Registration Program
PFC	Perfluorocarbon
PFYC	Potential Fossil Yield Classification
PG&E	Pacific Gas and Electric Company
PHMSA	Pipeline and Hazardous Materials Safety Administration
PI	Pacific Institute
PL	Platted Lands (zoning district)
PM	Particulate Matter
PMA	Projects and management action
PM_{10}	Particulate Matter less than 10 Microns

$PM_{2.5}$	Particulate Matter less than 2.5 Microns
Porter-Cologne	Porter-Cologne Water Quality Control Act
ppb	Parts per Billion
ppm	Parts per Million
ppmv	Parts per Million Volume
PPV	Peak Particle Velocity
PRC	Public Resources Code
Project or proposed Project	Amendment to Chapter 19.98 (Oil and Gas Production) of the Kern County Zoning Ordinance
PSD	Prevention of Significant Deterioration
PSIA	Pipeline Safety Improvement Act
PSM	Process Safety Management
PTO	Permits to Operate
PV	Photovoltaic
PVC	Polyvinyl Chloride
PXP	Plains Exploration and Production Company
QK	Quad Knopf
R-1, R-2, and R-3	Low, Medium, and High-Density Residential respectively (zoning districts)
RACM	Reasonably Available Control Measures
RACT	Reasonably Available Control Technology
RCRA	Resource Conservation and Recovery Act
RECs	Reduced Emission Completions
REL	Recommended Exposure Limit
Responsible Agencies	state, regional, and local agencies and departments with discretionary approval authority for some component of the oil and gas activities covered by this Supplemental Recirculated Environmental Impact Report
RF	Recreation-Forestry (zoning district)
RFS-2	Reformulated Fuels Standard
RHNA	Regional Housing Needs Allocation
RMP	Resource Management Plan
ROD	Record of Decision
ROG	Reactive Organic Gases
ROP	Rate of Progress
ROW	Right-of-Way

RPF	Registered Professional Forester
RPS	Renewable Portfolio Standard
RSPA	Research and Special Provisions Administration
RTP	Regional Transportation Plan
RTPA	Regional Transportation Planning Agency
RUSLE	Revised Universal Soil Loss Equation
RV	Recreational Vehicle
RWQCB	Regional Water Quality Control Board
SANDAG	San Diego Association of Governments
SAPT	Standard Annular Pressure Test
SARA	Superfund Amendments and Reauthorization Act
SB	Senate Bill
SBM	Statistical-based Model
SCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SCEDC	Southern California Earthquake Data Center
SCS	Sustainable Communities Strategy
SDS	Safety Data Sheet
SDWA	Safe Drinking Water Act
SEIR	Supplemental Environmental Impact Report
SF_6	Sulfur Hexafluoride
SGMA	Sustainable Groundwater Management Act
SHPO	State Historic Preservation Office(r)
SHS	State Highway System
SIC	Standard Industry Classification
SIP	State Implementation Plan
SJAPCD	San Joaquin Air Pollution Control District
SJV	San Joaquin Valley
SJV Recovery Plan	Recovery Plan for the Upland Species of the San Joaquin Valley
SJVAB	San Joaquin Valley Air Basin
SJVAPCD	San Joaquin Valley Air Pollution Control District
SMARA	Surface Mining and Reclamation Act
SMBRP	Site Mitigation and Brownfields and Reuse Program
SMGB	State Mining and Geology Board

SNF	Sequoia National Forest
SO_2	Sulfur Dioxide
SO_4^{2-}	Sulfate
SoCalGas	Southern California Gas Company
SO_X	Sulfur Oxides
SP	Special Planning (zoning district)
SPCC	Spill Prevention, Control, and Countermeasures
SR	State Route
SRA	State Responsibility Area
SREIR	Supplemental Recirculated Environmental Impact Report
SRRE	Source Reduction and Recycling Element
SSC	Species of Special Concern
SSMP	Sewer System Management Plan
SSURGO	Soil Survey Geographic
ST	State Listed as Threatened
STORET	Storage and Retrieval
STRONGER	State Review of Oil and Natural Gas Environmental Regulations
SVOC	Semi-Volatile Organic Compound
SVRA	State Vehicular Recreation Area
SWAMP	Surface Water Ambient Monitoring Program
SWANCC	Solid Waste Agency of Northern Cook County
SDWA	Safe Drinking Water Act of 1974
SWP	State Water Project
SWPPP	Stormwater Pollution Prevention Plan
SWRCB	State Water Resources Control Board
TAC	Toxic Air Contaminant
TCLP	Toxicity Characteristic Leaching Procedure
TDS	Total Dissolved Solids
TEOR	Thermally Enhanced Oil Recovery
THLPSSC	Technical Hazardous Liquids Pipeline Safety Standards Committee
TI	Traffic Index
TMDL	Total Maximum Daily Load
TRC	TRC Operating Company, Inc.
TUMSHCP	Tehachapi Uplands Multiple Species Habitat Conservation Plan

U.S.C.	United States Code
UBC	Uniform Building Code
UFC	Uniform Fire Code
UIC	Underground Injection Control
UNFCCC	United Nations Framework Convention on Climate Change
USACE	United States Army Corps of Engineers
USBR	U.S. Bureau of Reclamation
USDA	United States Department of Agriculture
USDOE	U.S. Department of Energy
USDM	U.S. Drought Monitor
USDOT	U.S. Department of Transportation
USDW	Underground Source of Drinking Water
USFS	United States Forest Service
USFWS	United States Fish and Wildlife Service
USGS	United States Geological Survey
USLE	Universal Soil Loss Equation
UST	Underground Storage Tank
UWMP	Urban Water Management Plan
V/C	Volume to Capacity
Vector	Vector Environmental, Inc.
VERA	Voluntary Emission Reduction Agreement
VFHCP	Valley Floor Habitat Conservation Plan
VMT	Vehicle Miles Traveled
VOC	Volatile Organic Compound
VOCDD	Volatile Organic Compound Destruction Devices
WD	Water District
WDR	Waste Discharge Requirement
WDWA	Westside District Water Authority
WHO	World Health Organization
Williamson Act	California Land Conservation Act of 1965
WKWD	West Kern Water District
WL	Watch List
WMD	Kern County Waste Management Department
WOUS	Waters of the United States
WQA	Water Quality Act

WRI	World Resources Institute
WSA	Waterway Supply Assessment
WSD	Water Storage District
WSPA	Western States Petroleum Association
WST	Well Stimulation Treatment
WWTP	Wastewater Treatment Plant
ZEV	Zero-Emission Vehicle

11.2 Glossary

-A-

Abandoned Well When a well is no longer needed, either because the oil or gas reservoir becomes depleted, or because no oil or gas was found (called a dry-hole), the well is plugged and abandoned. A well is plugged by placing cement in the well-bore or casing at certain intervals as specified in California laws or regulations. The purpose of the cement is to seal the wellbore or casing and prevent fluid from migrating between underground rock layers. Cement plugs are required to be placed across the oil or gas reservoir (zone plug), across the base-of-fresh-water (BFW plug), and at the surface (surface plug). Other cement plugs may be required at the bottom of a string of open casing (shoe plug), on top of tools that may become stuck down hole (junk plug), on top of cut casing (stub plug), or anywhere else where a cement plug may be needed. Also, the hole is filled with drilling mud to help prevent the migration of fluids. (DOGGR 2013a)

Abandonment (also see "abandon", "plug and abandon") To temporarily or permanently cease production from a well or to cease further drilling operations. (OSHA 2014)

Acidize (also see acid well stimulation treatment) To pump acid into the wellbore to remove near-well formation damage and other damaging substances. This procedure commonly enhances production by increasing the effective well radius. When performed at pressures above the pressure required to fracture the formation, the procedure is often referred to as acid fracturing. (Schlumberger Limited 2014)

Acid Volume Threshold	"Acid Volume Threshold" means a volume, in US gallons, per treated foot of well stimulation treatment, calculated as follows: (((Size of the drill bit diameter in inches that was used in the treated zone/2 + 36 inches)^2 - (bit diameter in inches/2)^2) x 3.14159 x 12 inches x treated formation porosity)/231 (inches^3/gallon). The lowest calculated or measured porosity in the zone of treated formation shall be the treated formation porosity used for calculating the Acid Volume Threshold. (SB-4)
Acid Well Stimulation Treatment	A well stimulation treatment that uses, in whole or in part, the application of one or more acids to the well or underground geologic formation. The acid well stimulation treatment may be at any applied pressure and may be used in combination with hydraulic fracturing treatments or other well stimulation treatments. Acid well stimulation treatments include acid matrix stimulation treatments and acid fracturing treatments. (SB-4)
Active Observation Well	A well being used for the sole purpose of gathering reservoir data, such as pressure or temperature in a reservoir being currently produced or injected by the operator, and the data is gathered at least once every three years. (DOGGR 2013a)
Alluvium	A fine-grained fertile soil consisting of mud, silt, and sand deposited by flowing water on flood plains, in river beds, and in estuaries.
Alquist-Priolo Earthquake Fault Zone	In 1972, the State of California delineated Special Studies Zones around active and potentially active faults in the State. The zones extend about six hundred and sixty (660) feet on either side of the identified fault traces. No structure for human occupancy may be built across an identified fault trace. An area of fifty (50) feet on either side of an active fault trace is assumed to be underlain by the fault unless proven otherwise.
American Petroleum Institute (API)	A trade association and standards organization that represents the interests of the oil and gas industry. It offers publications regarding standards, recommended practices, and other industry related information. (OSHA 2014)
Ancillary Equipment and Facilities (BLM)	Equipment, facilities, or structure(s) that often are required in oil and gas fields usually used to house or contain operating, maintenance, or support equipment and functions, other than wells and pipelines, such as compressor stations. Ancillary equipment and facilities required for enhanced recovery methods include producing steam, and pressurizing steam or water, typically through larger cogeneration plants serving the well fields where these techniques are utilized.
Annular Pressure	Pressure in an annular space (between the tubing and casing in a well [well bore]). (OSHA 2014)

Annular Valve (annular blowout preventer)	A large valve used to control wellbore fluids. In this type of valve, the sealing element resembles a large rubber doughnut that is mechanically squeezed inward to seal on either pipe (drill collar, drillpipe, casing, or tubing) or the openhole. The ability to seal on a variety of pipe sizes is one advantage the annular blowout preventer has over the ram blowout preventer. Most blowout preventer (BOP) stacks contain at least one annular BOP at the top of the BOP stack, and one or more ram-type preventers below. While not considered as reliable in sealing over the openhole as around tubulars, the elastomeric sealing doughnut is required by API specifications to seal adequately over the openhole as part of its certification process. (Schlumberger Limited 2014)
Annulus	The space around a pipe in a well bore, sometimes termed the annular space. (OSHA 2014)
API Number	American Petroleum Institute Well Number (also called **API**) is a unique, permanent, numeric identifier assigned to each oil and gas well in the US. An API Well number can have up to 14 digits divided into State Code (2 digits), County Code (3 digits), Unique Well Identifier (5 digits), Directional Sidetrack Code (2 digits), Event Sequence Code (2 digits). As of 2014, API Numbers in the DOGGR Well Finder database consist of 8 digits - County Code (first 3 digits) and Unique Well Identifier
Aquifer (BLM)	A water-bearing bed or layer or permeable rock, sand, of gravel capable of yielding water.
Archaeological Site	A site is defined by the National Register of Historic Places (NRHP) as the place or places where the remnants of a past culture survive in a physical context that allows for the interpretation of these remains. Archaeological remains usually take the form of artifacts (e.g., fragments of tools, vestiges of utilitarian, or non-utilitarian objects), features (e.g., remnants of walls, cooking hearths, or midden deposits), and ecological evidence (e.g., pollen remaining from plants that were in the area when the activities occurred). **Prehistoric archaeological sites** generally represent the material remains of Native American groups and their activities dating to the period before European contact. In some cases, prehistoric sites may contain evidence of trade contact with Europeans. **Ethnohistoric archaeological sites** are defined as Native American settlements occupied after the arrival of European settlers in California. **Historic archaeological sites** reflect the activities of nonnative populations during the Historic period.
Artifact	An object that has been made, modified, or used by a human being.
Assembly Bill 32	"Assembly Bill 32" (AB 32) is the Global Warming Solutions Act was passed in California on August 31, 2006 requiring the State's global warming emissions to be reduced to 1990 levels by 2020. The reduction will be accomplished through an enforced statewide cap on GHG emissions that will be phased.

-B-

Berm (BLM)
"Berm" means a raised area with vertical or sloping sides, often used to prevent, minimize, stabilize, mitigate or eliminate the release or threat of hazardous waste or hazardous substance. (Association of Environmental Professionals 2014)

Best Available Control Technology
Section 169(3) of the federal Clean Air Act defines "Best Available Control Technology" (BACT) as an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best available control technology" result in emissions of any pollutant which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act. Emissions from any source utilizing clean fuels, or any other means, to comply with this paragraph shall not be allowed to increase above levels that would have been required under this paragraph as it existed prior to enactment of the federal Clean Air Act Amendments of 1990. (CAPCOA BACT Clearinghouse 2000)

Best Management Practice
"Best Management Practice" (BMP) means mandatory mitigation measures and/or development standards in the revised zoning ordinances, and as appropriate includes revisions to these BMPs to address the project-level circumstances in Core and non-Core areas, and Tiers.

Biological Resources (Baldwin Hills EIR)
"Biological Resources" means class of resources found on a project site, according to the California Environmental Quality Act, that includes plant or animal species or habitat that can be classified as either a significant ecological resource or sensitive environmental resource.

Blooie Line
A discharge line used in conjunction with a rotating head. (BLM 1988)

Blowout
An uncontrolled flow of reservoir fluids into the wellbore, and sometimes catastrophically to the surface. A blowout may consist of salt water, oil, gas or a mixture of these. Blowouts occur in all types of exploration and production operations, not just during drilling operations. If reservoir fluids flow into another formation and do not flow to the surface, the result is called an underground blowout. If the well experiencing a blowout has significant openhole intervals, it is possible that the well will bridge over (or seal itself with rock fragments from collapsing formations) downhole and intervention efforts will be averted. (Schlumberger Limited 2014)

-C-

Carrier Fluid	A fluid that is used to transport materials into or out of the wellbore. Carrier fluids typically are designed according to three main criteria: the ability to efficiently transport the necessary material (such as pack sand during a gravel pack), the ability to separate or release the materials at the correct time or place, and compatibility with other wellbore fluids while being nondamaging to exposed formations. (Schlumberger Limited 2014)
Casing–	(Drilling) Large-diameter pipe lowered into an openhole and cemented in place. The well designer must design casing to withstand a variety of forces, such as collapse, burst, and tensile failure, as well as chemically aggressive brines. Most casing joints are fabricated with male threads on each end, and short-length casing couplings with female threads are used to join the individual joints of casing together, or joints of casing may be fabricated with male threads on one end and female threads on the other. Casing is run to protect fresh water formations, isolate a zone of lost returns or isolate formations with significantly different pressure gradients. The operation during which the casing is put into the wellbore is commonly called "running pipe." Casing is usually manufactured from plain carbon steel that is heat-treated to varying strengths, but may be specially fabricated of stainless steel, aluminum, titanium, fiberglass and other materials. (Schlumberger Limited 2014) (Well Completions) Steel pipe cemented in place during the construction process to stabilize the wellbore. The casing forms a major structural component of the wellbore and serves several important functions: preventing the formation wall from caving into the wellbore, isolating the different formations to prevent the flow or crossflow of formation fluid, and providing a means of maintaining control of formation fluids and pressure as the well is drilled. The casing string provides a means of securing surface pressure control equipment and downhole production equipment, such as the drilling blowout preventer (BOP) or production packer. Casing is available in a range of sizes and material grades. (Schlumberger Limited 2014) Casing Shoe– 1. The bottom of the casing string, including the cement around it, or the equipment run at the bottom of the casing string. 2. A short assembly, typically manufactured from a heavy steel collar and profiled cement interior, that is screwed to the bottom of a casing string. The rounded profile helps guide the casing string past any ledges or obstructions that would prevent the string from being correctly located in the wellbore. (Schlumberger Limited 2014) Casing String– An assembled length of steel pipe configured to suit a specific wellbore. The sections of pipe are connected and lowered into a wellbore, then cemented in place. The pipe joints are typically approximately 40 ft [12 m] in length, male threaded on each end and connected with short lengths of double-female threaded pipe called couplings. Long casing strings may require higher strength materials on the upper portion of the string to withstand the string load. Lower portions of the string may be assembled with casing of a greater wall

	thickness to withstand the extreme pressures likely at depth. Casing is run to protect or isolate formations adjacent to the wellbore. The following are the most common reasons for running casing in a well: 1) protect fresh-water aquifers (surface casing) 2) provide strength for installation of wellhead equipment, including BOPs 3) provide pressure integrity so that wellhead equipment, including BOPs, may be closed 4) seal off leaky or fractured formations into which drilling fluids are lost 5) seal off low-strength formations so that higher strength (and generally higher pressure) formations may be penetrated safely 6) seal off high-pressure zones so that lower pressure formations may be drilled with lower drilling fluid densities 7) seal off troublesome formations, such as flowing salt 8) comply with regulatory requirements (usually related to one of the factors listed above). (Schlumberger Limited 2014)
	(Well Completions) An assembly of valves, spools, pressure gauges and chokes fitted to the wellhead of a completed well to control production. Christmas trees are available in a wide range of sizes and configurations, such as low- or high-pressure capacity and single- or multiple-completion capacity. (Schlumberger Limited 2014) It is used when reservoir pressure is sufficient to cause reservoir fluids to rise to the surface. (OSHA 2014)
Cathodic Devices (also see sacrificial anode)	A protective device to prevent electrolytic corrosion. Anodes (often made of Mg or Al metal) are sacrificed intentionally to protect a steel system, such as a buried pipeline or offshore platform. (Schlumberger Limited 2014)
Christmas Tree (Drilling)	The set of valves, spools and fittings connected to the top of a well to direct and control the flow of formation fluids from the well. (Schlumberger Limited 2014)
Cogeneration	The process of generating two or more forms of energy from a single energy source. For example, in a heavy oil field, turbines are often used to generate electricity while their waste heat is removed to generate steam. Other alternatives exist, with turbines being run by burning gas or crude oil. Alternatively, the primary heat source can be used to generate steam directly at extremely high pressure and temperature, with the steam being run through a turbine to generate electricity before the steam is distributed to injection wells. (Schlumberger Limited 2014)
Color	The hue (e.g., red, brown) and value (e.g., light, dark) of the light reflected by objects in the visual landscape.
Completion Operations	A generic term used to describe the assembly of downhole tubulars and equipment required to enable safe and efficient production from an oil or gas well. The point at which the completion process begins may depend on the type and design of well. However, there are many options applied or actions performed during the construction phase of a well that have significant impact on the productivity of the well. (Schlumberger Limited 2014)

Contrast The opposition or unlikeness of different forms, lines, colors, or textures in a landscape.

Critical Well A well within 300 feet of the following: Any building intended for human occupancy that is not necessary to the operation of the well or Any airport runway; or 100 feet of the following: Any dedicated public street, highway, or nearest rail of an operating railway that is in general use or any navigable body of water or watercourse perennially covered by water or any public recreational facility such as a golf course, amusement park, picnic ground, campground, or any other area of periodic high-density population, or any officially recognized wildlife preserve. (State of California 2011)

Cuttings (Drilling) Small pieces of rock that break away due to the action of the bit teeth. Cuttings are screened out of the liquid mud system at the shale shakers and are monitored for composition, size, shape, color, texture, hydrocarbon content and other properties by the mud engineer, the mud logger and other on-site personnel. The mud logger usually captures samples of cuttings for subsequent analysis and archiving. (Schlumberger Limited 2014)

Cyclic Steaming (Cyclic Steam Injection) A method of thermal recovery in which a well is injected with steam and then subsequently put back on production. A cyclic steam-injection process includes three stages. The first stage is injection, during which a slug of steam is introduced into the reservoir. The second stage, or soak phase, requires that the well be shut in for several days to allow uniform heat distribution to thin the oil. Finally, during the third stage, the thinned oil is produced through the same well. The cycle is repeated as long as oil production is profitable. Cyclic steam injection is used extensively in heavy-oil reservoirs, tar sands, and in some cases to improve injectivity prior to steamflood or in situ combustion operations. Cyclic steam injection is also called steam soak or the huff `n puff (slang) method. (Schlumberger Limited 2014)

-D-

Derrick The structure used to support the crown blocks and the drillstring of a drilling rig. Derricks are usually pyramidal in shape, and offer a good strength-to-weight ratio. If the derrick design does not allow it to be moved easily in one piece, special ironworkers must assemble them piece by piece, and in some cases disassemble them if they are to be moved. (Schlumberger Limited 2014)

Direct or Primary Impact Impact that is caused by the proposed project and occur at the same time and place of project implementation.

Disposal Well A well, often a depleted oil or gas well, into which waste fluids can be injected for safe disposal. Disposal wells typically are subject to regulatory requirements to avoid the contamination of freshwater aquifers. (Schlumberger Limited 2014)

Directional Drilling

The intentional deviation of a wellbore from the path it would naturally take. This is accomplished through the use of whipstocks, bottomhole assembly (BHA) configurations, instruments to measure the path of the wellbore in three-dimensional space, data links to communicate measurements taken downhole to the surface, mud motors and special BHA components and drill bits, including rotary steerable systems, and drill bits. The directional driller also exploits drilling parameters such as weight on bit and rotary speed to deflect the bit away from the axis of the existing wellbore. In some cases, such as drilling steeply dipping formations or unpredictable deviation in conventional drilling operations, directional-drilling techniques may be employed to ensure that the hole is drilled vertically. While many techniques can accomplish this, the general concept is simple: point the bit in the direction that one wants to drill. The most common way is through the use of a bend near the bit in a downhole steerable mud motor. The bend points the bit in a direction different from the axis of the wellbore when the entire drillstring is not rotating. By pumping mud through the mud motor, the bit turns while the drillstring does not rotate, allowing the bit to drill in the direction it points. When a particular wellbore direction is achieved, that direction may be maintained by rotating the entire drillstring (including the bent section) so that the bit does not drill in a single direction off the wellbore axis, but instead sweeps around and its net direction coincides with the existing wellbore. Rotary steerable tools allow steering while rotating, usually with higher rates of penetration and ultimately smoother boreholes. Directional drilling is common in shale reservoirs because it allows drillers to place the borehole in contact with the most productive reservoir rock. (Schlumberger Limited 2014)

Distribution Lines (medium-voltage, NOT high-voltage transmission lines)

"Distribution Lines" means an electrical line which delivers power through conductors, usually medium voltage (not more than 50kV), to the end user. Typical construction of distribution lines consist mainly of poles, insulator, connectors, and wires. Distribution systems are typically set up in an overhead configuration but highly urbanized areas may utilize an underground system by using power cables and cabinet substations.

Drilling

To prepare a well to be closed permanently, usually after either logs determine there is insufficient hydrocarbon potential to complete the well, or after production operations have drained the reservoir. Different regulatory bodies have their own requirements for plugging operations. Most require that cement plugs be placed and tested across any open hydrocarbon-bearing formations, across all casing shoes, across freshwater aquifers, and perhaps several other areas near the surface, including the top 20 to 50 ft [6 to 15 m] of the wellbore. The well designer may choose to set bridge plugs in conjunction with cement slurries to ensure that higher density cement does not fall in the wellbore. In that case, the bridge plug would be set and cement pumped on top of the plug through drillpipe, and then the drillpipe withdrawn before the slurry thickened. (Schlumberger Limited 2014)

Drill/Drilling – (NOR)

Drilling is the process of drilling a hole or "wellbore" in the ground for the purpose of extracting crude oil or natural gas resources or for the injection of a fluid from surface to a subsurface reservoir. Drilling may be in field, exploratory or development. In field drilling is intended to maximize recovery of oil and natural gas within the defined and known subsurface reserves. (Kern County 2013)

"Prospect well" or **"exploratory well"** means any well drilled to extend a field or explore a new, potentially productive reservoir. **"Development well"** is a well drilled into a known producing formation in a previously discovered field, to be distinguished from a wildcat, exploratory, or offset well. (California Department of Conservation, Division of Oil, Gas, and Geothermal Resources 2014)

Exploratory drilling is intended to determine whether the resource exists in a specific area and whether extraction is economically viable. Exploration can also be characterized as defining the lateral limits of hydrocarbons outside of a known producing area (i.e., step-out zone). Development drilling consists of drilling wells to extract known hydrocarbon resources to efficiently maximize the development of the reservoir or field. Most current drilling projects are classified as development within existing administrative field boundaries or "in field." (Kern County 2013)

Drilling Island (DI) District

A Zoning District in the Kern County Zoning Ordinance (Chapter 1948) applied to single lots and relatively small areas within the boundaries of final map subdivisions and mobilehome parks that contain productive or potentially productive petroleum resources. Uses in the DI District are limited to petroleum and gas exploration, production and transportation, and to compatible open space and recreational uses. (Kern County 2012)

Drilling Fluids

(Rock pieces dislodged by the drill bit as it cuts rock in the hole. Cuttings are distinct from cavings, rock debris that spalls as a result of wellbore instability. Visual inspection of rock at the shale shaker usually distinguishes cuttings from cavings. (Schlumberger Limited 2014)

Drilling Muds

Any of a number of liquid and gaseous fluids and mixtures of fluids and solids (as solid suspensions, mixtures and emulsions of liquids, gases and solids) used in operations to drill boreholes into the earth. Synonymous with "drilling fluid" in general usage, although some prefer to reserve the term "drilling fluid" for more sophisticated and well-defined "muds." Classification of drilling fluids has been attempted in many ways, often producing more confusion than insight. One classification scheme, given here, is based only on the mud composition by singling out the component that clearly defines the function and performance of the fluid: (1) water-base, (2) non-water-base and (3) gaseous (pneumatic). Each category has a variety of subcategories that overlap each other considerably. (Schlumberger Limited 2014)

Drilling Pad A temporary drilling site, usually constructed of local materials such as gravel, shell or even wood. For some long-drilling-duration, deep wells, such as the ultradeep wells of western Oklahoma, or some regulatory jurisdictions such as The Netherlands, pads may be paved with asphalt or concrete. After the drilling operation is over, most of the pad is usually removed or plowed back into the ground. (Schlumberger Limited 2014)

Drilling Rig The machine used to drill a wellbore. In onshore operations, the rig includes virtually everything except living quarters. Major components of the rig include the mud tanks, the mud pumps, the derrick or mast, the drawworks, the rotary table or topdrive, the drillstring, the power generation equipment and auxiliary equipment. Offshore, the rig includes the same components as onshore, but not those of the vessel or drilling platform itself. The rig is sometimes referred to as the drilling package, particularly offshore. (Schlumberger Limited 2014)

Drilling Sumps "Drilling Sump" means a sump used in conjunction with well drilling operations. (California Code of Regulations. Title 14, Division 2, Chapter 4. Development, Regulation, and Conservation of Oil and Gas Resources, Subchapter 2, Article 3, Section 1770(c))

Drilling sumps are large earthen pits historically used to contain oil, production water, and drilling mud during drilling operations. Sumps vary in size from an average residential lot, to the size of a football field. (Shell Oil Products US 2014)

DOGGR requires all free fluids to be removed from drilling sumps within 30 days after the date the drill rig is disconnected from the well. (California Code of Regulations. Title 14, Division 2, Chapter 4. Development, Regulation, and Conservation of Oil and Gas Resources, Subchapter 2, Article 3, Section 1770(c)).

Dwelling Unit "Dwelling Unit" means (1) or more habitable rooms which are designed to be occupied by one (1) family with facilities for living, sleeping, cooking, eating, and sanitation

-E-

Emergency Work (Delano) "Emergency Work" means any work performed for the purpose of preventing or alleviating the physical trauma or property damage threatened or caused by an emergency.

Emerging Production Field A production field with an "emerging" resource type, such as shale oil and gas or coal bed natural gas. In some instances, these areas may not have seen large scale exploration and production activities until the last 10 to 15 years and as a result, they might be held to a higher environmental protection standard. These fields typically are emerging due to a combination of rising energy costs and new extraction technologies, which can introduce unique issues associated with the exploration and production. specifically the lack of existing infrastructure (roads, pipelines, power, etc.) necessary to effectively deliver the resource to market, and therefore, the amount of new disturbances can be greater than infill drilling in a vintage field (even for the same number of wells). (IOGCC 2008)

Enhanced Oil Recovery (EOR) An oil recovery enhancement method using sophisticated techniques that alter the original properties of oil. Once ranked as a third stage of oil recovery that was carried out after secondary recovery, the techniques employed during enhanced oil recovery can actually be initiated at any time during the productive life of an oil reservoir. Its purpose is not only to restore formation pressure, but also to improve oil displacement or fluid flow in the reservoir. The three major types of enhanced oil recovery operations are chemical flooding (alkaline flooding or micellar-polymer flooding), miscible displacement (carbon dioxide [CO_2] injection or hydrocarbon injection), and thermal recovery (steamflood or in-situ combustion). The optimal application of each type depends on reservoir temperature, pressure, depth, net pay, permeability, residual oil and water saturations, porosity and fluid properties such as oil API gravity and viscosity. Enhanced oil recovery is also known as improved oil recovery or tertiary recovery and it is abbreviated as EOR. (Schlumberger Limited 2014)

Environment The physical conditions that exist within the area that will be affected by the proposed project, including, but not limited to land, air, water, minerals, flora, fauna, ambient noise, and objects of historical or aesthetic significance. The area involved is the locale in which significant direct or indirect impacts would occur as a result of the project. The environment includes both natural and man-made conditions.

Ethnographic Relating to the study of human cultures. "Ethnographic resources" represent the heritage resource of a particular ethnic or cultural group, such as Native Americans or African, European, Latino, or Asian immigrants. They may include traditional resource-collecting areas, ceremonial sites, value-imbued landscape features, cemeteries, shrines, or ethnic neighborhoods and structures.

Exploration or Exploratory Drilling Exploration is the initial phase in petroleum operations that includes generation of a prospect or play or both, and drilling of an exploration well. Appraisal, development and production phases follow successful exploration. "Exploratory Drilling" means the drilling intended to determine whether the resource exists in a specific area and whether extraction is economically viable. (Schlumberger Limited 2014)

-F-

Flare An arrangement consisting of a vertical tower and burners used to burn combustible vapors. A flare is usually situated near a producing well or at a gas plant or refinery. A flare is also called a flare stack. (Schlumberger Limited 2014)

Flowback The process of allowing fluids to flow from the well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. (Schlumberger Limited 2014)

Flowback Fluid The fluid recovered from the treated well before the commencement of oil and gas production from that well following a well stimulation treatment. The flowback fluid may include materials of any phase. (SB-4)

Forest Land Land that can support 10 percent native tree cover of any species, including hardwoods, under natural conditions, and that allows for management of one or more forest resources, including timber, aesthetics, fish and wildlife, biodiversity, water quality, recreation, and other public benefits. (Public Resources Code Section 12220 (g))

Fracking Hydraulic fracturing (also known as hydrofracturing, "fracking," or "fracing") is the injection of a mixture of water, chemicals, and substances (primarily silica sand) called "proppants" into a well at pressures greater than the fracturing pressure of the oil-bearing formation.

Fugitive Dust "Fugitive Dust" is particulate matter (or solid particles which come primarily from the soil) suspended in the air by wind action and hum activities. It has not come out of a vent or a stack, and is usually not a by-product of burning. Fugituve dust particles are composed mainly of soil minerals (e.g., oxides of silicon, aluminum, calcium, and iron), but can also contain sea salt, pollen, spores, tire particles, etc. (CARB 2007)

-G-

Gas Any natural hydrocarbon gas coming from the earth. (DOGGR 2013a)

Gathering Line A pipeline (independent of size) that transports liquid hydrocarbons between any of the following: multiple wells, a testing facility, a treating and production facility, a storage facility, or a custody transfer facility (ACTF). (DOGGR, n.d.)

Geophysical Surveys The tests conducted to determine the extent of the presence of natural gas and oil reserves and whether the resources require additional development for production. The surveys generate low-frequency sound waves and the date is recorded by small geophones strategically placed in the survey area. The low-frequency sound waves are produced by using specialized trucks to vibrate the ground (vibroseis) or through detonating charges underground (shothole). (Kern County 2013)

-H-

Historic Period The period that begins with the arrival of the first nonnative population and thus varies by area. In 1772, Commander Don Pedro Fages was the first European to enter Kern County, initiating the historic period in the project study area.

Historical Resource This term is used for the purposes of CEQA and is defined in the CEQA Guidelines (§15064.5) as: (1) a resource listed in, or determined to be eligible for listing in the California Register of Historical Resources (CRHR); (2) a resource included in a local register of historical resources, as defined in Public Resources Code (PRC) §5020.1(k) or identified as significant in a historical resource survey meeting the requirements of PRC §5024.1(g); and (3) any object, building, structure, site, area, place, record, or manuscript which a lead agency determines to be historically significant or significant in the architectural, engineering, scientific, economic, agricultural, educational, social, political, military, or cultural annals of California by the lead agency, provided the lead agency's determination is supported by substantial evidence in light of the whole record.

Holocene Of, denoting, or formed in the second and most recent epoch of the Quaternary period, which began 10,000 years ago at the end of the Pleistocene.

Horizontal Drilling A subset of the more general term "directional drilling," used where the departure of the wellbore from vertical exceeds about 80 degrees. Note that some horizontal wells are designed such that after reaching true 90-degree horizontal, the wellbore may actually start drilling upward. In such cases, the angle past 90 degrees is continued, as in 95 degrees, rather than reporting it as deviation from vertical, which would then be 85 degrees. Because a horizontal well typically penetrates a greater length of the reservoir, it can offer significant production improvement over a vertical well. (Schlumberger Limited 2014)

Hydraulic Fracturing A well stimulation treatment that, in whole or in part, includes the pressurized injection of hydraulic fracturing fluid or fluids into an underground geologic formation in order to fracture or with the intent to fracture the formation, thereby causing or enhancing, the production of oil or gas from a well. (SB-4)

Hydrostatic Testing One of the primary ways in which California pipeline safety standards exceed the minimum federal standards is in pipeline integrity testing. Federal regulations mandate that a pipeline system be hydrostatically tested before initial operation begins. California laws mandates that each pipeline system be tested at least every five years by an independent third-party approved by the Office of the State Fire Marshal (SFM). In these hydrostatic tests the hazardous liquid is removed from the pipe and replaced with water. The pipe is then pressurized to 125% of the maximum pipeline operating pressure and held for eight hours. Testing results are submitted to SFM for review and concurrence. Tests are randomly witnessed by SFM engineers. In certain cases, SFM has approved the use of internal inspection tools "smart pigs" in lieu of hydrostatic testing. In these cases, the test results are also submitted to the SFM for review and concurrence. (Office of the State Fire Marshall 2013)

-I-

Idle Well **"Idle well"** means a well, other than a suspended well, that has not been officially plugged and abandoned, on which the operator has ceased all activity, including but not limited to drilling, production or injection. California Code of Regulations. Title 14, Division 2, Chapter 4. Development, Regulation, and Conservation of Oil and Gas Resources, Subchapter 2, Article 3, Section 1770(c)). Testing of idle wells is required for any well that has not produced oil or natural gas or has not been used for injection for six (6) consecutive months of continuous operation during the last five (5) or more years. It does not include an active observation well. (DOGGR 2013b)

Indirect or Secondary Impacts Impacts that are caused by the proposed project at a later time or farther removed in distance but are still reasonably foreseeable. Indirect or secondary impacts may include growth-inducing impacts and other effects related to induced changes in the pattern of land use, population density or growth rate, or related effects on air, water, and other natural systems, including ecosystems.

Infrastructure Necessary Infrastructure" is any on-site and off-site facilities which are necessary to the development and maintenance of the well pad such as: access roads, electrical transmission lines, and pipelines; but are not directly related to the exploration and drilling process.

Injection Well A well into which fluids are injected rather than produced, the primary objective typically being to maintain reservoir pressure. Two main types of injection are common: gas and water. Separated gas from production wells or possibly imported gas may be reinjected into the upper gas section of the reservoir. Water-injection wells are common offshore, where filtered and treated seawater is injected into a lower water-bearing section of the reservoir. (Schlumberger Limited 2014)

Intactness	The visual integrity of the natural and human-built landscape and its freedom from encroaching elements; this factor can be present in well-kept urban and rural landscapes, as well as in natural settings. (FHWA 1981)
Isolate	An isolated artifact or small group of artifacts that appear to reflect a single event, loci, or activity. It may lack identifiable context but has the potential to add important information about a region, culture, or person. Isolates are not considered under CEQA to be significant and, thus, do not require avoidance mitigation (CEQA Statute §21083.2 and CEQA Guidelines §15064.5). All isolates located during the field effort, however, are recorded and the data are transmitted to the appropriate California Historical Resources Information System (CHRIS) Information Center.

-K-

Key Observation Point (KOP)	One or a series of points on a travel route or at a use area or potential use area where the view of a management activity (project) would be the most revealing (USFS 1995).

-L-

Landslides and Rock falls	Landslides and Rock falls are large movements of land downhill. They can be induced by seismic events (earthquakes) or wet saturated soil conditions and can cause significant damage to life and property.
Line (in reference to aesthetics and visual resources)	The well-defined edges of shapes or masses created in the visual landscape by horizons, silhouettes, or human-made features. This element of visual character is usually the second strongest (USFS 1995).
Liquefaction	A process by which water-saturated sediment temporarily loses strength and acts as a fluid, like when you wiggle your toes in the wet sand near the water at the beach. This effect can be caused by earthquake shaking. (USGS Earthquake Hazards Program 2012)
Lithic	Of or pertaining to stone. Specifically, in archaeology lithic artifacts are chipped or flaked stone tools, and the stone debris resulting from their manufacture.
Long-Term Idle Well	Any well that has not produced oil or natural gas or has not been used for injection for six (6) consecutive months of continuous operation during the last ten (10) or more years. A long-term idle well does not include an active observation well. (DOGGR 2013b)

-M-

Maintenance

The division (DOGGR) shall, by regulation, prescribe minimum facility maintenance standards for all production facilities in the state. The regulations shall include, but are not limited to, standards for all of the following:

(1) Leak detection.
(2) Corrosion prevention and testing.
(3) Tank inspection and cleaning.
(4) Valve and gauge maintenance, and secondary containment maintenance.
(5) Other facility or equipment maintenance that the supervisor deems important for the proper operation of production facilities and that the supervisor determines are necessary to prevent damage to life, health, property, and natural resources; damage to underground oil and gas deposits from infiltrating water and other causes; loss of oil, gas, or reservoir energy; and damage to underground and surface waters suitable for irrigation or domestic purposes by the infiltration of, or the addition of, detrimental substances.

(b) An operator who constructs, acquires, maintains, or alters an oil well or a production facility shall comply with the standards prescribed pursuant to subdivision (a).

(c) In a form and at a time prescribed by the division in regulation, an operator shall notify the supervisor of the construction, alteration, or decommissioning of a production facility.

(d) An operator shall maintain at the production facility's local office records of maintenance and repair operations, tests, and inspections, and shall provide the supervisor with access to these records at all times during normal business hours and with copies of the records immediately, upon request. (DOGGR 2013a).

Master Development Plan

"Master Development Plan" provides information common to multiple planned wells, including drilling plans, Surface Use Plans of Operations, and plans for future production; they are typically prepared for a planned cluster of wells and associated facilities in close proximity, or for multiple in-fill wells scattered throughout an oil and gas Unit or field, and include information on associated facilities (roads, pipelines, utility corridors, compressor stations, etc.). (BLM 2015).

Midstream Operation (Loyalsock, PA)

"Midstream Operations" means the compressors, compressor stations, meters and processing plants that support more than one well pad. (All operations and facilities constructed or installed between the well heads and the main product transportation line.)

Ministerial Decision “Ministerial decision” means a decision requiring the application of the statutes, ordinance, or regulations to the facts as prescribed and involving little or no personal judgment by the public official or decision-making body as to the wisdom or manner of carrying out a project.

Mitigation Measures “Mitigation Measures” are actions taken to reduce or minimize potential impacts to the environment.

Mitigation Monitoring or Reporting Program In 1989, the Legislature added to CEQA a requirement that a public agency, in approving feasible mitigation measures contained in EIRs and negative declarations, must also adopt a mitigation monitoring and reporting program. Such a program is to be designed to ensure compliance with the changes to a project which were required by the public agency in order to reduce or avoid significant environmental effects. (City of Winters 2015)

-N-

Native American Sacred Site An area that has been, and often continues to be, of religious significance to Native American peoples, such as an area where religious ceremonies are practiced or an area that is central to their origins as a people. They also include areas where Native Americans gather plants for food, medicinal or economic purposes.

Native Species (BLM) “Native Species” are plants or animals that originated in the area in which they are found (i.e. they naturally occur in that area); with respect to a particular ecosystem, a species that, other than as a result of an introduction, historically occurred or currently occurs in that ecosystem.

Natural Gas (Geology) A naturally occurring mixture of hydrocarbon gases that is highly compressible and expansible. Methane [CH_4] is the chief constituent of most natural gas (constituting as much as 85% of some natural gases), with lesser amounts of ethane [C_2H_6], propane [C_3H_8], butane [C_4H_{10}] and pentane [C_5H_{12}]. Impurities can also be present in large proportions, including carbon dioxide, helium, nitrogen and hydrogen sulfide. (Shale Gas) Natural gas produced from shale reservoirs is known as shale gas. The composition of the gas stream is a function of the thermal maturity of the rock. Thermally immature rocks will contain heavier hydrocarbon components, possibly even liquid components. Overmature reservoirs typically contain appreciable quantities of carbon dioxide [CO_2]. (Schlumberger Limited 2014)

New Well (Baldwin Hills EIR) “New well” means a well bore established at the ground surface and not including the redrilling or reworking of an existing well. An abandoned well that is reentered will be considered a new well for purposes of drilling, redrilling, and reworking.

Non-Associated Gas Natural gas which is in reservoirs that do not contain significant quantities of crude oil (Schlumberger Limited 2014)

Nonnative Invasive Species (BLM) "Nonnative Invasive Species" are plant species that are introduced into an area in which they did not evolve, and in which they usually have few or no natural enemies to limit their reproduction and spread. These species can cause environmental harm by significantly changing ecosystem composition, structure, or processes, and can cause economic harm or harm to human health.

Notice of Preparation (Baldwin Hills EIR) "Notice of Preparation" is a document preceding an Environmental Impact Report, that provides notice to interested agencies (responsible, trustee, and federal) and stakeholders, that the Lead Agency plans to prepare and Environmental Impact Report for a project. The Notice of Preparation includes a project description and a scope of content to be covered by the Environmental Impact Report.

-O-

Oil and Gas Conformity Review A new "Oil and Gas Conformity Review" would be established as a ministerial permit procedure for County approval of future well drilling and operations to ensure compliance with the updated development standards and conditions and provide for ongoing tracking and compliance monitoring. This review will allow for comprehensive review of all drilling activities and will require consistent, comprehensive mitigation based on defined tiers of surrounding land uses as specified in the Amended Zoning Ordinance. An application package must be submitted that includes a site plan and written documentation assuring compliance with all applicable Development Standards and Conditions.

Oil and Gas Lease Any contact, profit-share agreement, joint venture, or other agreement issued or approved by the United States under a mineral leasing law that authorizes exploration for, extraction of, or removal of oil or gas (see 43 CFR 3160.0-5). (BLM 1988)

A contract between mineral owner, otherwise known as the lessor and a company or working interest owner, otherwise known as the lessee in which the lessor grants the lessee the right to explore, drill and produce oil, gas and other minerals for a specified primary term and as long thereafter as oil, gas or other minerals are being produced in paying quantities. This lease gives the lessee a working interest. The oil and gas lease is granted in exchange for royalty payments to the lessor. (Schlumberger Limited 2014)

Oil Operation (Baldwin Hills EIR)	"Oil Operation" means the use or maintenance of any installation, facility, or structure used, either directly or indirectly, to carry out or facilitate one or more of the following functions: drilling, redrilling, reworking and repair, production, processing, extraction, Enhanced Recovery, stimulation, abandonment, storage or shipping of oil or gas from the subsurface of the earth. It does not include administrative operations (e.g., work carried on in the administrative office buildings).
Oil or Gas Exploration by Scientific Means	Includes, but is not limited to, the following: seismic surveys, magnetotelluric, magnetometer or gravity meter surveys; surface mapping and holes less than five hundred (500) feet deep drilled for the purpose of taking core samples, velocity readings, temperature measurements, or water samples. (USFS 1995) Oil Field – means an accumulation, pool or group of pools of oil in the subsurface. An oil field consists of a reservoir in a shape that will trap hydrocarbons and that is covered by an impermeable or sealing rock. Typically, industry professionals use the term with an implied assumption of economic size. (Schlumberger Limited 2014)
Oil Well	A producing well with oil as its primary commercial product. Oil wells almost always produce some gas and frequently produce water. Most oil wells eventually produce mostly gas or water. (Schlumberger Limited 2014)
Operations	Any one or all of the activities of an operator covered by Division 3 of the Public Resources Code. (State of California 2011)
Operation Sumps	"Operations sump" means a sump used in conjunction with an abandonment or rework operation. For operational sumps, DOGGR requires that all free fluids shall be removed from operations sumps within 14 days after the rig removal or from completion of operations, whichever occurs first. (California Code of Regulations. Title 14, Division 2, Chapter 4. Development, Regulation, and Conservation of Oil and Gas Resources, Subchapter 2, Article 3, Section 1770(c)).
Orphan Well	A well that has been deserted and has no viable operator or owner. The Division maintains a list of orphan wells that are available for adoption under the "adopt a well" program. The well list may be downloaded in Acrobat PDF or Excel formats. This program allows prospective operators to enter into a three-way agreement (PDF) to test an orphan well for up to 90 days without incurring any liability for plugging the well. If the test is successful, the prospective operator can adopt the well by posting a bond and becoming its permanent operator. If the test is unsuccessful, the prospective operator can walk away from the agreement with no liability incurred. (Kern County 2012)

-P-

Paleontological Resources (Fossils) The physical remains of plants and animals preserved in soils and sedimentary rock formations. Paleontological resources contribute to the understanding of past environments, environmental change, and the evolution of life.

Percolation Ponds Similar to a sump, a percolation pond acts as a holding facility while gravity allows the water to percolate or seep through the soils. A percolation pond is used to dispose of water associated with hydrocarbon production. A natural or artificial evaporation pond is a pond with a large surface area that is designed to efficiently evaporate water by exposure to sunlight. In contrast to sumps, evaporation and percolation ponds are not designed to separate oil and other contaminates from water, but rather are intended for water disposal. Percolation and evaporation ponds vary in size, but are typically between two and five acres and can be as shallow as five feet deep. Some facilities contain multiple ponds totaling as much as 80 acres. The State Water Resources Control Board adopts site-specific WDRs for percolation and evaporation ponds.

Perforate To create holes in the casing or liner to achieve efficient communication between the reservoir and the wellbore. The characteristics and placement of the communication paths (perforations) can have significant influence on the productivity of the well. Therefore, a robust design and execution process should be followed to ensure efficient creation of the appropriate number, size and orientation of perforations. A perforating gun assembly with the appropriate configuration of shaped explosive charges and the means to verify or correlate the correct perforating depth can be deployed on wireline, tubing or coiled tubing. (Shale Gas) The creation of holes in the casing or liner to achieve efficient communication between the reservoir and the wellbore. This process is integral to the optimal creation of hydraulic fractures. Geomechanical analysis is commonly conducted before perforating shale reservoirs to account for the relationship between formation stresses and productivity. (Schlumberger Limited 2014)

Perforated Interval (DOC) The section of wellbore that has been prepared for production by creating channels between the reservoir formation and the wellbore. In many cases, long reservoir sections will be perforated in several intervals, with short sections of unperforated casing between each interval to enable isolation devices, like packers, to be set for subsequent treatments or remedial operations. (Schlumberger Limited 2014)

Permanently Illuminated Oil, Gas, Or Other Hydrocarbon Well Activities Does not include drilling operations, reworks.

Pigging The act of forcing a device called a pig through a pipeline for the purposes of displacing or separating fluids, and cleaning or inspecting the line. (Schlumberger Limited 2014)

Pipeline A tube or system of tubes used for transporting crude oil and natural gas from the field or gathering system to the refinery. (Schlumberger Limited 2014)

Planning Director "Planning Director" means the Director of the Planning and Community Development Department of the County of Kern or his/her designee.

Pleistocene (Ice Age) An epoch in the Quaternary period of geologic history lasting from 1.8 million to 10,000 years ago. The Pleistocene was an epoch of multiple glaciation, during which continental glaciers covered nearly one fifth of the earth's land.

Pool An underground reservoir containing, or appearing at the time of determination to contain, a common accumulation of crude petroleum oil or natural gas or both. Each zone of a general structure which is separated from any other zone in the structure is a separate pool. (State of California 2011)

Prehistoric Period The era prior to 1772. The later part of the prehistoric period (post-1542) is also referred to as the protohistoric period in some areas, which marks a transitional period during which native populations began to be influenced by European presence resulting in gradual changes to their lifeways.

Production Facility Any equipment attendant to oil and gas production or injection operations including, but not limited to, tanks, flow lines, headers, gathering lines, wellheads, heater treaters, pumps, valves, compressors, injection equipment, and pipelines that are not under the jurisdiction of the State Fire Marshal pursuant to Section 51010 of the Government Code. (DOGGR 2013a)

Production Well Production wells are current producing wells, whereas, I have no doubt WZI has intermingled these two terms and created a mess. We need to use them correctly.

Producible Well All wells that "can" produce.

Project Area The area within which the proposed amendment to Title 19 – Kern County Zoning Ordinance would apply.

Proppant (also Propping Agent) Materials inserted or injected into the underground geologic formation that are intended to prevent fractures from closing. (DOGGR 2013a)

A granular substance (sand grains, crushed walnut shells, aluminum pellet, or other material) that is carried in suspension by the fracturing fluid. Proppant keeps fractures open in a formation when fracturing fluid is withdrawing after a fracture treatment. (OSHA 2014)

Prospect Well/Exploratory well (DOGGR) Any well drilled to extend a field or explore a new, potentially productive reservoir. (DOGGR 2013a)

Protected Water "Protected water" means water outside of a hydrocarbon zone that contains no more than 10,000 mg/l total dissolved solids unless the water has been determined to be an exempt aquifer pursuant to the Code of Federal Regulations, title 40, part 146.4.

-Q-

Quaternary Age The most recent of the three periods of the Cenozoic Era in the geologic time scale of the International Commission on Stratigraphy (ICS). It follows the Tertiary Period, spanning 2.588 ± 0.005 million years ago to the present. The Quaternary includes two geologic epochs: the Pleistocene and the Holocene Epochs.

-R-

Redrilling (Culver City) Redrilling" means any drilling operation, including deviation from original well bore, to recomplete the well in the same or different geologic zone, excluding sidetracking (Bakersfield Municipal Code n.d.).

Remediation Cleanup or other methods used to remove or contain a toxic spill or hazardous materials from a Superfund site. (EPA 2011)

Repressuring Operations Gas injection operations, water injection operations, water flooding operations, or any combination thereof, or any other operations intended primarily to arrest or ameliorate subsidence, or to restore or increase the pressure in a pool, or to avoid or minimize a reduction of pressure within a pool. (DOGGR 2013a)

Reservoir A subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. Sedimentary rocks are the most common reservoir rocks because they have more porosity than most igneous and metamorphic rocks and form under temperature conditions at which hydrocarbons can be preserved. A reservoir is a critical component of a complete petroleum system. (Schlumberger Limited 2014)

Retention Basin (Baldwin Hills EIR) "Retention Basic" is a type of best management practice that is used to manage stormwater runoff to prevent flooding and downstream erosion and improve water quality in an adjacent river, stream, lake, or bay. It is essentially an artificial lake with vegetation around the perimeter, and includes a permanent pool of water in its design.

Rework To restore production from an existing formation when it has fallen off substantially or ceased altogether. (OSHA 2014)

Any operation subsequent to drilling that involves deepening, redrilling, plugging, or permanently altering in any manner the casing of a well or its function. (State of California 2011)

Right-of-Way (BLM) "Right-of-Way" is the legal right for use, occupancy, or access across land or water areas for a specified purpose or purposes.

Rural Agriculture and/or Ranching (IOGCC) "Rural Agriculture and/or Ranching" means a rural area where agriculture and livestock dominate the surface land use and will have surface disturbance issues specific to the area, including concerns about: Crops, Grazing/pasturelands, Water supply for livestock and irrigation, and Impacts to soil quality and vegetation stability.

-S-

Sacrificial Anode (also Galvanic Anode) A protective device to prevent electrolytic corrosion. Anodes (often made of Mg or Al metal) are sacrificed intentionally to protect a steel system, such as a buried pipeline or offshore platform. (Schlumberger Limited 2014)

Scoping Early consultation, also called scoping, provides the opportunity to identify the range of actions, alternatives, mitigation measures, and significant effects to be analyzed in depth in the environmental impact report. Guidelines Section 15083 provides that the lead agency may also consult with other persons or organizations which may be concerned with the environmental effects of the project. PRC Sections 21104 and 21153 require the lead agency to consult with responsible and trustee agencies and with adjoining cities and counties. (OPR 2001)

Seismic Hazards Seismicity is the geographic and historical distribution of earthquakes, including their frequency, intensity, and distribution. Seismic hazards include surface rupture, ground shaking, liquefaction, landslides, subsidence, expansive soils, and soil erosion.

Sensitive Habitat Areas which provide habitat for rare or endangered species which meet the definition of Section 15380 of the California Environmental Quality Act guidelines.

Set Back (also Lay Down Pipe) To place stands of drill pipe and drill collars in a vertical position to one side of the rotary table in the derrick or mast of a drilling or workover rig. (OSHA 2014)

Shale Gas A generic term used to describe the events and equipment necessary to bring a wellbore into production once drilling operations have been concluded, including but not limited to the assembly of downhole tubulars and equipment required to enable safe and efficient production from an oil or gas well. Completion quality can significantly affect production from shale reservoirs. (Schlumberger Limited 2014)

Shallow Cyclic Thermal Production "Shallow Cyclic Thermal Production" is the low permeability shallow cyclic thermal production operation in shallow, low permeability reservoirs that are produced primarily or exclusively through intermittent steam injection to create permeability channels or dilate a reservoir. It is a form of Enhanced Oil Recovery, steam injection.

Significant and Unavoidable Impact An impact that exceeds the defined thresholds of significance and cannot be eliminated or reduced to a less-than-significant level through the implementation of mitigation measures.

Significant Impact An impact that exceeds the defined thresholds of significance and would or could cause a substantial adverse change in the environment. Mitigation measures are recommended to eliminate the impact or reduce it to a less-than-significant level.

Slant Drilling See Directional drilling.

Slurry (DOC) 1. (Drilling) a plastic mixture of cement and water that is pumped into a well to harden. There it supports the casing and provides a seal in the wellbore to prevent migration of underground fluids. 2. a mixture in which solids are suspended in a liquid. (OSHA 2014)

Spill Prevention, Response, and Remediation (secondary containment structures) DOGGR regulates the minimum facility maintenance standards for production facilities. The regulations (14 CCR Sections 1722 – 1777.3) require operators to develop and implement spill contingency plans where condensate storage volume exceeds 50 barrels or at facilities that produce at least one barrel per day. The implementing regulations provide specific requirements for the spill contingency plan that include emergency contacts, available safety equipment, checklist for spill response, maps of the facility, a list of chemicals at the facility, containment features, corrosion prevention techniques, and the sensor and alarm systems. These plans may be fulfilled by SPCC plans if the SPCC plan is deemed adequate by DOGGR. Production facilities storing and/or processing fluids, with specific exceptions, shall have secondary containment that is capable of containing the volume of liquids from the container with the largest gross capacity within the secondary containment and should be able to confine the liquid for 72 hours. (AB 1960 Public Resources, Facilities and Oil Spills.)

Spud or Spudding Spud or Spudding means to begin drilling a well; to start the hole.

Standard Annular Pressure Test “Standard Annular Pressure Test” is a pressure test conducted using a fluid to fill the annular space between the casing, tubing and packer. Pressure is maintained for a specified time as a specified pressure. If the closed system retains the pressure after the pressure source is removed, the well is determined to have mechanical integrity.

Steam Injection (also Steamflood, Continuous Steam Injection) A method of thermal recovery in which steam generated at surface is injected into the reservoir through specially distributed injection wells. When steam enters the reservoir, it heats up the crude oil and reduces its viscosity. The heat also distills light components of the crude oil, which condense in the oil bank ahead of the steam front, further reducing the oil viscosity. The hot water that condenses from the steam and the steam itself generate an artificial drive that sweeps oil toward producing wells. Another contributing factor that enhances oil production during steam injection is related to near-wellbore cleanup. In this case, steam reduces the interfacial tension that ties paraffins and asphaltenes to the rock surfaces while steam distillation of crude oil light ends creates a small solvent bank that can miscibly remove trapped oil. (Schlumberger Limited 2014)

Step-Out Zone Step-out Zone” means an area of exploration drilling outside a known hydrocarbon producing area.

Stimulation (well stimulation treatment) Any treatment of a well designed to enhance oil and gas production or recovery by increasing the permeability of the formation. Well stimulation treatments include, but are not limited to, hydraulic fracturing treatments and acid well stimulation treatments. (State of California 2013)

Storage Facilities Includes Tanks, conveyance facilities, supportive piping. Various sizes of tanks typically are utilized to store oil prior to off-site transport. Such storage facilities can range in size from small to large tank arrangements with supportive piping and conveyance facilities. Storage facilities may also be located offsite. Crude oil produced in Kern County is shipped to offsite storage facilities or refineries to be processed into gasoline and other products via distribution pipelines, and/or tanker trucks.

Stratigraphy The natural and cultural layers of soil that make up an archaeological deposit, and the order in which they were deposited relative to other layers.

Subsidence Land subsidence is the gradual, local settling or shrinking of the earth’s surface with little or no horizontal motion. Subsidence is normally the result of gas, oil, or water extraction, hydro compaction, peat oxidation and not the result of landslide or ground failure. There are four types of subsidence occurring in the County: tectonic subsidence; subsidence from extraction of oil and gas; subsidence from groundwater withdrawal; and subsidence caused by hydrocompaction of moisture-deficient alluvial deposits.

Sump	"Sump" means a lined or unlined, covered, or uncovered excavation pit which holds petroleum or other liquids incidental thereto, or solids associated with drilling or production operations. (Bakersfield Municipal Code n.d.)
Surface Disturbing Activities (BLM)	"Surface Disturbing Activities" mean any authorized action that disturbs vegetation and surface soil, increasing erosion potential above normal site conditions. This definition typically applies to mechanized or mechanical disturbance. However, intense or extensive use of hand or motorized hand tools may fall into this category. Examples include construction of well pads and roads, pits and reservoirs, pipelines and power lines, mining, and vegetation treatments.
Surface Rupture	Surface rupture occurs when movement on a fault deep within the earth breaks through to the surface. Fault ruptures almost always follow pre-existing faults that are zones of weakness. Rupture may occur suddenly during an earthquake or slowly in the form of fault creep. Sudden displacements are more damaging to structures because they are accompanied by shaking. Fault creep is the slow rupture of the earth's crust.
Swabbing	(Drilling) To reduce pressure in a wellbore by moving pipe, wireline tools or rubber-cupped seals up the wellbore. If the pressure is reduced sufficiently, reservoir fluids may flow into the wellbore and towards the surface. Swabbing is generally considered harmful in drilling operations, because it can lead to kicks and wellbore stability problems. In production operations, however, the term is used to describe how the flow of reservoir hydrocarbons is initiated in some completed wells. (Well Completion) To unload liquids from the production tubing to initiate flow from the reservoir. A swabbing tool string incorporates a weighted bar and swab cup assembly that are run in the wellbore on heavy wireline. When the assembly is retrieved, the specially shaped swab cups expand to seal against the tubing wall and carry the liquids from the wellbore. (Schlumberger Limited 2014)

-T-

Tank	A metal or plastic vessel used to store or measure a liquid. The three types of tanks in an oil field are drilling, production and storage tanks. (Schlumberger Limited 2014)
Tank Battery	For crude oil production facilities, a tank battery is an aggregation of two or more tanks where the tanks are located so that no one tank is more than 150 feet from another tank as measured from the closest tank edges, and the tanks are located in the same crude oil production field. (SJVAPCD Rule 4623)
Temporary Facilities	Any structure or other man-made improvement that can be readily and completely dismantled and/or removed from the site when the authorized use terminates.

Texture The apparent surface coarseness of the visual landscape caused by the aggregation or density of surface features and vegetation (e.g., fine, medium, coarse). This element of visual character is usually the least dominant (USFS 1995)

Texture (BLM) The visual manifestations of the interplay of light and shadow created by the variations in the surface of an object or landscape.

Threatened Species (BLM) "Threatened Species" are any species (plant or animal) that is likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range. Threatened species are identified by the Secretary of the Interior in accordance with the 1973 Endangered Species Act.

Timberland Privately owned land, or land acquired for State forest purposes, which is devoted to and used for growing and harvesting timber, or for growing and harvesting timber and compatible uses, and which is capable of growing an average annual volume of wood fiber of at least 15 cubic feet per acre. (Public Resources Code Section 51104 (f))

Traditional Well A well completed without the use of well stimulation methodology

Trip Distribution A model of the number of trips that occur between each origin zone and each destination zone. It uses the predicted number of trips originating in each origin zone (trip production model) and the predicted number of trips ending in each destination zone (trip attraction model).

-U-

Unique Archaeological Resource This term is used for the purposes of CEQA and is defined in the CEQA Guidelines (§15064.5) as an archaeological artifact, object, or site, about which it can be clearly demonstrated that, without merely adding to the current body of knowledge, there is a high probability that it either contains information needed to answer important scientific research questions; has a special and particular quality such as being the oldest of its type or best available example of its type; or, is directly associated with a scientifically recognized important prehistoric or historic event or person.

Unique Paleontological Resource There is currently no legislated definition of this term. Current professional practice utilizes a definition parallel to that for Unique Archaeological Resources above. A unique paleontological resource is a fossil or locality about which it can be clearly demonstrated that, without merely adding to the current body of knowledge, there is a high probability that it either provides information needed to answer important scientific research questions; has a special and particular quality such as being the oldest of its type or best available example of its type; or, is directly associated with a scientifically recognized important natural event.

Unity The visual coherence and compositional harmony of the landscape considered as a whole; it frequently attests to the careful design of individual components in the landscape. (FHWA 1981).

-V-

View Corridor A view corridor is typically defined as the line of sight of an observer from a public viewpoint, looking toward an object of significance to the community (e.g., ridgeline, river, historic building) or as the route that directs the viewers' attention. (USFS 1995)

Viewshed The landscape that can be directly seen under favorable atmospheric conditions, from a viewpoint or along a transportation corridor. (BLM 1984)

The landscape that can be directly seen under favorable atmospheric conditions, from a viewpoint or along a transportation corridor. (USFS 1995)

Vintage Production Field "Vintage Production Field" means a production field where oil and gas activities have been ongoing for several decades or more. The development of these fields often pre-date environmental laws and / or conservation efforts, and as a result they might pose unique restoration and management challenges. (IOGCC 2008)

Vividness The visual power or memorability of landscape components as they combine in striking or distinctive visual patterns. (FHWA 1981).

-W-

Water Injection "Water Injection", also referred to as "Water Flooding" is the process of injecting water into the reservoir via an injection well for the purposes of "sweeping" the hydrocarbons to a nearby production well where it can be recovered to the surface.

Watershed A watershed is the area of land where all of the water that is under it or drains off of it goes into the same place. (EPA 2012)

Waters of the States (Water Code Section 13050(e) Any surface water or groundwater, including saline waters, within the boundaries of the state.

Waters of the United States or Waters of the US (40 CFR 122.2)

(a) All waters which are currently used, were used in the past, or may be susceptible to use in interstate or foreign commerce, including all waters which are subject to the ebb and flow of the tide;
(b) All interstate waters, including interstate "wetlands;"
(c) All other waters such as intrastate lakes, rivers, streams (including intermittent streams), mudflats, sandflats, "wetlands," sloughs, prairie potholes, wet meadows, playa lakes, or natural ponds the use, degradation, or destruction of which would affect or could affect interstate or foreign commerce including any such waters:
(1) Which are or could be used by interstate or foreign travelers for recreational or other purposes;
(2) From which fish or shellfish are or could be taken and sold in interstate or foreign commerce; or
(3) Which are used or could be used for industrial purposes by industries in interstate commerce;
(d) All impoundments of waters otherwise defined as waters of the United States under this definition;
(e) Tributaries of waters identified in paragraphs (a) through (d) of this definition;
(f) The territorial sea; and
(g) "Wetlands" adjacent to waters (other than waters that are themselves wetlands) identified in paragraphs (a) through (f) of this definition.

Well

Any oil or gas well or well for the discovery of oil or gas; any well on lands producing or reasonable presumed to contain oil or gas; any well drilled for the purpose of injecting fluids or gas for stimulating oil or gas recovery, repressuring, or pressure maintenance of oil or gas reservoirs, or disposing of waste fluids from an oil or gas field; any well used to inject or withdraw gas from an underground storage facility; or any well drilled within or adjacent to an oil or gas pool for the purpose of obtaining water to be used in production stimulation or repressuring operations. (DOGGR 2013a) (State of California 2011)

Wellbore

The drilled hole or borehole, including the openhole or uncased portion of the well. Borehole may refer to the inside diameter of the wellbore wall, the rock face that bounds the drilled hole. (Schlumberger Limited 2014)

Well Completion

1. The activities and methods of preparing a well for the production of oil and gas or for other purposes, such as injection; the method by which one or more flow paths for hydrocarbons are established between the reservoir and the surface. 2. The system of tubulars, packers, and other tools installed beneath the wellhead in the production casing; that is, the tool assembly that provides the hydrocarbon flow path or paths. (OSHA 2014)

To prepare a wellbore to be shut in and permanently isolated. There are typically regulatory requirements associated with the P&A process to ensure that strata, particularly freshwater aquifers, are adequately isolated. In most cases, a series of cement plugs is set in the wellbore, with an inflow or integrity test made at each stage to confirm hydraulic isolation. (Schlumberger Limited 2014)

Wellfield (BLM) "Wellfield" is an area containing one or more wells that produce usable amounts of water or oil.

Wellhead The system of spools, valves and assorted adapters that provide pressure control of a production well. (Schlumberger Limited 2014)

Well Pad Preparation Well pad preparation begins with clearing and grading an area to accommodate the well and any drilling activities or ancillary facilities that may be required. The size of the well pad is dependent upon the size of the drilling rig footprint, the number of wells anticipated to be drilled on the pad, the type of equipment that would be placed on the well during production, the depth of the well, and the number of additional wells (if any) from this well pad.

Well Remedial Operations (Workover) (Drilling) The repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons. (Well Workover and Intervention) The process of performing major maintenance or remedial treatments on an oil or gas well. In many cases, workover implies the removal and replacement of the production tubing string after the well has been killed and a workover rig has been placed on location. Through-tubing workover operations, using coiled tubing, snubbing or slickline equipment, are routinely conducted to complete treatments or well service activities that avoid a full workover where the tubing is removed. This operation saves considerable time and expense. (Schlumberger Limited 2014)

Well-Spacing Plan A well spacing plan describes the pool to which it applies and set forth the surface and subsurface well spacing pattern for all wells to be drilled or redrilled into the pool. The Supervisor gives the greatest consideration to the minimum spacing, in acres per well, that can be established based on the geologic geometry of the pool and the area that can be effectively and efficiently drained by a well without economic loss. (Section 3609, Public Resources Code.)

Well Stimulation Treatment Well stimulation treatment does not include routine well cleanout work; routine well maintenance; routine treatment for the purpose of removal of formation damage due to drilling; bottom hole pressure surveys; routine activities that do not affect the integrity of the well or the formation; the removal of scale or precipitate from the perforations, casing, or tubing; a gravel pack treatment that does not exceed the formation fracture gradient; or a treatment that involves emplacing acid in a well and that uses a volume of fluid that is less than the Acid Volume Threshold for the operation and is below the formation fracture gradient. (Final Text of SB-4. 12-30-14)

Williamson Act Lands Lands preserved for agricultural production under the California Land Conservation Act of 1965 or "Williamson Act." In exchange for a ten-year agreement that agricultural land will not be developed or converted to another use, the land is taxed at a rate based on the actual use of the land for agricultural purposes, as opposed to its unrestricted market value.

Woodlands Forest lands composed mostly of hardwood species such as oak (Public Resources Code Section 12220 (l))

Workover Rig A portable rig used for working over a well. (OSHA 2014)

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Zonal Isolation Zonal Isolation means that oil and gas coming up a well form the productive, underground geologic zone will not escape the well and migrate into other geologic zones, including zones that might contain fresh water. Zonal Isolation also means that the fluids an oil and gas operator puts down a well for any purpose will stay in that zone and not migrate to another zone. (California Department of Conservation 2012)

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