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 2
Appendices to the SREIR
(Appendix A – G)

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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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

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

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Technical Assistance by:
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October 2020

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Appendix A

Initial Study/Notice of Preparation

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Web Address: https://kernplanning.com/

PLANNING AND NATURAL RESOURCES DEPARTMENT

Planning
Community Development
Administrative Operations

NOTICE OF PREPARATION

DATE: April 29, 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: NOTICE OF PREPARATION OF A DRAFT SUPPLEMENTAL RECIRCULATED ENVIRONMENTAL IMPACT REPORT (SCH # 2013081079)

The Kern County (County) Planning and Natural Resources Department, as Lead Agency (pursuant to California Environmental Quality Act [CEQA] Guidelines Section 15050 *et seq.*) has determined that preparation of a Draft Supplemental Recirculated Environmental Impact Report (SREIR) is necessary for the Project identified below. The Planning and Natural Resources Department solicits the views of your agency as to the scope and content of the environmental information which is germane to your agency's statutory responsibilities about the proposed project. Your agency will need to use the SREIR prepared by our agency when considering your permit or other approval of projects.

Due to the limits mandated by State law, your response must be received by **May 29, 2020, at 5 p.m.** In addition, comments can also be submitted at a virtual scoping meeting on **May 13, 2020, at 1:30 pm.** In compliance with the Governor's Executive Order, the California Department of Public Health's guidelines on gatherings regarding COVID-19, and Kern County Local Emergency Declaration, the scoping meeting required by the California Environmental Quality Act Guidelines will be conducted online. Instructions for accessing the virtual scoping meeting will be available three (3) days before the virtual scoping meeting on the Kern County Planning and Natural Resources website at https://kernplanning.com/.

Comments on the Notice of Preparation and project should be sent to **hooverc@kerncounty.com**.

PROJECT TITLE: Revisions to Title 19- Kern County Zoning Ordinance (2020-A) Focused on Oil and Gas Local Permitting (SCH # 2013081079)

PROJECT LOCATION: The project boundary 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 is defined by the San Luis Obispo County line on the west; the Kings and Tulare County lines on the north; the 2,000-foot elevation contours, squared off to the nearest section line on the east; and the northern boundary of the Los Padres National Forest on the south.

PROJECT DESCRIPTION: The proposed project is the reconsideration of revisions to Title 19 of the Kern County Zoning Ordinance (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 January 2013, the California Independent Petroleum Association, Independent Oil Producers Agency, and Western States Petroleum Association (the "Project Proponents") requested that the County consider amending the Ordinance as summarized above. Under Chapter 19.112 of the Ordinance, 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. On November 9, 2015, the County certified a Final Environmental Impact Report (EIR) and approved the proposed Ordinance revisions as amendments to Title 19.

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 entirety 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 $PM_{2.5}$ [fine particulate matter] 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 26, 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 focused on Oil and Gas Local Permitting.

Document can be viewed online at: https://kernplanning.com/final-environmental-impact-report-revisions-kern-county-zoning-ordinance-2015-c-focused-oil-gas-local-permitting/.

Signature: Cindi Hoover
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 04/17/20)

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City of Arvin
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Bakersfield, CA 93301

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California City, CA 93515

Delano City Planning Dept
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Delano, CA 93216

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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
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Taft, CA 93268

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Santa Barbara, CA 93101

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

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San Luis Obispo, CA 93408

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Caliente/Bakersfield
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Bakersfield, CA 93308-6837

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Ventura County RMA Planning Div
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Ventura, CA 93009-1740

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Ridgecrest, CA 93555

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Hopper Mountain (Bitter Creek)
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Sacramento, CA 94273-0001

Caltrans/
Division of Structures
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Director's Office
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State Dept of Conservation
Geologic Energy Management Division
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State Dept of Conservation
Office of Mine Reclamation
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State Dept of Conservation
Div Recycling Cert. Sec.
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State Mining and Geology Board
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Control Board/Central Valley Region
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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

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3801 Chester Avenue
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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

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California City Airport
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Kern Valley Indian Council
Historic Preservation Office
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San Fernando Band of Mission Indians
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Environmental Planning Team
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Kern River Valley Chamber of Commerce
Katherine Evans
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Tehachapi, CA 93561-2011

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Nature Conservancy West Reg Office
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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

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1717 - 28th Street
Bakersfield, CA 93301

Tulare Basin Wetlands Association
Attention Dennis Slater
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Bakersfield City Parks & Rec Dept
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Bakersfield, CA 93301

Buttonwillow Rec & Parks Dist
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Buttonwillow, CA 93206-9320

Vintage Petroleum, LLC
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Bakersfield, CA 93311

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Shafter Rec & Parks Dist
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Shafter, CA 93263

Tehachapi Parks & Recreation Dist
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Tehachapi, CA 93561

West Side Rec & Parks Dist
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Frazier Park, CA 93225

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Lake Isabella, CA 93240

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East Niles Community Serv Dist
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Golden Hills Community Serv Dist
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Ashe Water Dist
Dept of Water Resources
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Bakersfield, CA 93309

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

Arvin-Edison Water Storage Dist
P.O. Box 175
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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
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Weldon, CA 93283

Brock Mutual Water Co
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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
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Goose Lake Water Co
16232 Palm Avenue
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California Regional Water Quality
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Kern Water Bank Authority
1620 Mill Rock Way, Suite 500
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Wheeler Ridge-Maricopa Water Dist
12109 Highway 166
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Kern-Tulare Water Dist
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La Hacienda Water Co, Inc.
P.O. Box 60679
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Indian Wells Valley Water Dist
P.O. Box 1329
Ridgecrest, CA 93556

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

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Kern River Valley Water Co
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Davenport Mutual Water Assn
P.O. Box 1503
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Mountain Mesa Water Co
12707 Highway 178
Lake Isabella, CA 93240

Lake of the Woods
Mutual Water Co.
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1822 Steven Drive
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North of the River Muni Water Dist
P.O. Box 5638
Bakersfield, CA 93388-5638

Lebec County Water Dist
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Lebec, CA 93243

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

Pinion Pines Mutual Water Co
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Lost Hills Water Dist
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Bakersfield, CA 93309

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Riverkern Mutual Water Co
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Kernville, CA 93238

North Edwards Water Dist
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Rand Communities Co Water Dist
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Ridgecrest, CA 93555-4436

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Antelope Valley Resource Cons Dist
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Richland-Lerdo Union School Dist
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Shafter, CA 93263

Lerdo School Dist
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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

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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
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300 S Robinson Street
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Beardsley School Dist
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Bakersfield, CA 93308

Taft Union High School Dist
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Taft, CA 93268

Wasco Union Elementary School Dist
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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 (2020 A) 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: Approximately 2.3 million square acres
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
☒ Zoning Ordinance

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 Map Code Designations to remain the same.

Project Description: The proposed project is the preparation of a Supplemental Recirculated EIR (SREIR) for 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). On November 9, 2015 the Kern County Board of Supervisors approved amendments 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 (Ordinance) to address oil and gas exploration and operation activities within the Project Area in greater detail. The Board of Supervisors 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

Continued

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

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

Starting Date April 29, 2020 Ending Date May 29, 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:** April 29, 2020

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

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INITIAL STUDY/NOTICE OF PREPARATION

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

Requested by:

California Independent Petroleum Association
Western States Petroleum Association

Kern County Planning and Natural Resources Department
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1. PROJECT DESCRIPTION

1.1 Project Location

The project area is located in the western half of Kern County (County) and encompasses 3,700 square miles, which generally includes most of the San Joaquin Valley Floor portion of Kern County up to an elevation of 2,000 feet and additional areas in the southern portion of the project area. The project boundary is defined by the San Luis Obispo, Monterey, and Santa Barbara County lines on the west; the Kings and Tulare County lines on the north; the 2,000-foot elevation contours, squared off to the nearest section line on the east; and the northern boundary of the Los Padres National Forest and portions of the San Emigdo and Tehachapi Mountains on the south. The project boundary is based on information regarding areas with potential or confirmed oil and gas resources within the County's jurisdiction. The location of the project area is shown in **Figure 1-1 (Project Area Regional Location)**.

Kern County is California's third-largest county in 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. The County includes 11 incorporated cities within the San Joaquin Valley portion, 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 occur within this area in the coming decades. For this reason, the SREIR evaluates potential impacts of future oil and gas exploration and production activities, to be specified, in a defined boundary as shown in **Figure 1-1 (Project Area Regional Location),** below. For purposes of this project, this area will be referred to as the Project Boundary Area.

The Project Boundary Area includes all unincorporated lands within the 409-square-mile Metropolitan Bakersfield General Plan. However, the Project Boundary Area 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. The Project Boundary is based on generally available information regarding areas with potential or confirmed oil and gas resources within the County's jurisdiction.

The Kern County General Plan Update 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. 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 San Joaquin Valley Air Pollution Control District. 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.

A total of 100 active or abandoned oil fields are currently delineated by California Geologic Energy Management Division (CalGEM) are located within the Project Boundary Area (**Figure 1-2, Administrative Oilfields in the Project Area by Subarea and Oilfield Status [Active or Abandoned]**). As shown on **Table 1-1**, these CalGEM-delineated oil fields vary widely in size—from the smallest, Kernsumner and Temblor East Well Fields at 0.2 square miles, to the largest, Midway Sunset Well Field at 99.7 square miles. Oil and gas production also occurs outside of CalGEM-delineated oilfield boundaries.

Table 1-1: Oil Fields Currently Delineated by CalGEM within the Project Boundary Area

Count	Administrative Oil Field (Alpha Order)	Square Miles*	Acres*
1	Ant Hill	1.7	1,098.0
2	Antelope Hills	4.4	2,823.7
3	Antelope Plains Gas (Abd)	0.3	160.5
4	Asphalto	4.6	2,975.5
5	Beer Nose	1.0	644.8
6	Belgian Anticline	15.4	9,864.9
7	Bellevue	3.6	2,326.4
8	Blackwells Corner	3.6	2,308.1
9	Bowerbank	16.2	10,352.4
10	Buena Vista	46.9	29,993.3
11	Buttonwillow Gas (Abd)	10.0	6,378.7
12	Cal Canal Gas	5.5	3,515.2
13	Calders Corner	1.5	970.0
14	Canal	3.9	2,476.7
15	Canfield Ranch	13.3	8,536.4
16	Capitola Park	1.0	651.5
17	Carneros Creek	1.5	967.3
18	Chico Martinez	2.6	1,634.8
19	Cienaga Canyon	0.6	402.4
20	Comanche Point	1.9	1,202.7
21	Cymric	21.5	13,757.8
22	Devils Den	12.8	8,175.4
23	Dyer Creek	0.4	239.9
24	Eagle Rest	0.5	309.3
25	Temblor, East (Abd)	0.2	154.6
26	Edison	34.0	21,742.3
27	Elk Hills	72.9	46,630.7
28	English Colony	1.1	681.5
29	Fruitvale	18.3	11,714.2
30	Garrison City Gas (Abd)	4.7	3,017.4
31	Gonyer Anticline (Abd)	0.5	344.9
32	Goosloo	3.0	1,935.4
33	Greeley	9.4	6,022.4
34	Jasmin	10.3	6,607.4
35	Jerry Slough (Abd)	0.5	318.0
36	Kern River	25.8	16,532.6
37	Kern Bluff	4.2	2,668.6
38	Kern Front	19.0	12,136.1
39	Kernsumner (Abd)	0.2	159.7
40	Lakeside	1.3	804.0
41	Landslide	2.1	1,373.9
42	Los Lobos	6.1	3,892.3

Table 1-1: Oil Fields Currently Delineated by CalGEM within the Project Boundary Area

Count	Administrative Oil Field (Alpha Order)	Square Miles*	Acres*
43	Lost Hills	33.2	21,273.1
44	McClung (Abd)	0.5	319.6
45	McDonald Anticline	3.7	2,372.4
46	McKittrick	10.6	6,776.8
47	Midway – Sunset **	99.7	63,832.8
48	Monument Junction	3.3	2,085.6
49	Mountain View	28.5	18,251.2
50	Mount Poso	45.9	29,360.5
51	Antelope Hills, North	3.9	2,466.8
52	Belridge, North	9.1	5,800.9
53	Coles Levee, North	15.1	9,671.0
54	Shafter, North	7.5	4,768.3
55	Tejon, North	9.2	5,914.3
56	Edison, Northeast	0.6	408.8
57	Lost Hills, Northwest	8.6	5,507.7
58	Semitropic Gas, Northwest (Abd)	0.5	322.5
59	Paloma	29.7	18,985.0
60	Pioneer	1.0	642.8
61	Pleito	3.0	1,927.3
62	Poso Creek	30.9	19,806.9
63	Railroad Gap	1.7	1,101.2
64	Rio Bravo	6.1	3,925.0
65	Rio Viejo	4.1	2,641.7
66	Rose	5.5	3,522.1
67	Rosedale	3.6	2,321.0
68	Rosedale Ranch	5.0	3,213.3
69	Round Mountain	19.2	12,265.9
70	Round Mountain South	0.4	276.7
71	San Emidio Nose	7.6	4,880.5
72	San Emigdio (Abd)	0.5	306.1
73	San Emigdio Creek (Abd)	0.5	340.7
74	Semitropic	25.1	16,077.3
75	Seventh Standard	0.5	320.3
76	Shafter (Abd)	0.5	321.2
77	Shafter Southeast Gas (Abd)	1.0	641.5
78	Shale Flats Gas (Abd)	1.0	647.1
79	Shale Point Gas	0.6	387.2
80	Bellridge, South	25.3	16,218.0
81	Coles Levee, South	17.7	11,328.4
82	Lakeside, South (Abd)	0.3	160.4
83	Stockdale	2.4	1,567.5
84	Strand	7.9	5,068.5
85	Tejon	11.3	7,227.8
86	Tejon Flats (Abd)	0.3	161.0
87	Tejon Hills	6.7	4,283.2
88	Temblor Hills	1.0	643.9
89	Temblor Ranch	0.5	318.4
90	Ten Section	7.4	4,725.9
91	Trico Gas **	6.8	4,359.4

Table 1-1: Oil Fields Currently Delineated by CalGEM within the Project Boundary Area

Count	Administrative Oil Field (Alpha Order)	Square Miles*	Acres*
92	Union Ave.	1.0	655.3
93	Valpredo	0.3	163.1
94	Wasco	4.0	2,575.6
95	Welcome Valley	0.8	490.4
96	Bellevue, West	2.0	1,248.3
97	Jasmin, West (Abd)	0.5	321.6
98	Wheeler Ridge	8.1	5,203.7
99	White Wolf	1.3	846.3
100	Yowlumne	10.1	6,446.8
	TOTAL	**931.4**	**596,198.3**

Source: California Division of Oil, Gas and Geothermal Resources, Field Boundaries, March 6, 2013.
Notes:
* Numbers are approximate.
** Oil field is located on the border of Kern County and an adjacent county; acreages within Kern County are approximate.
Key:
Abd = Abandoned.

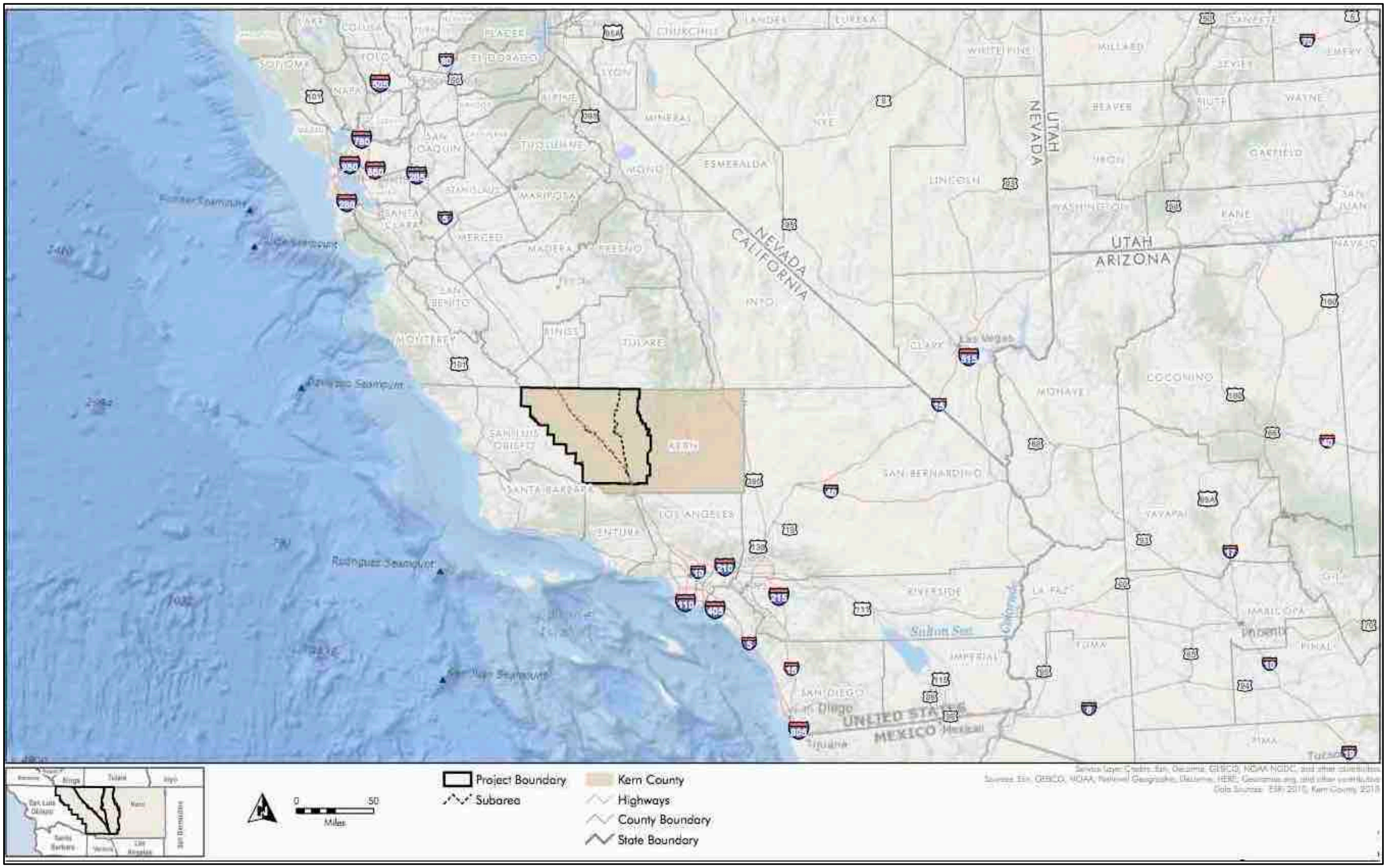

Figure 1-1: Project Area Regional Location

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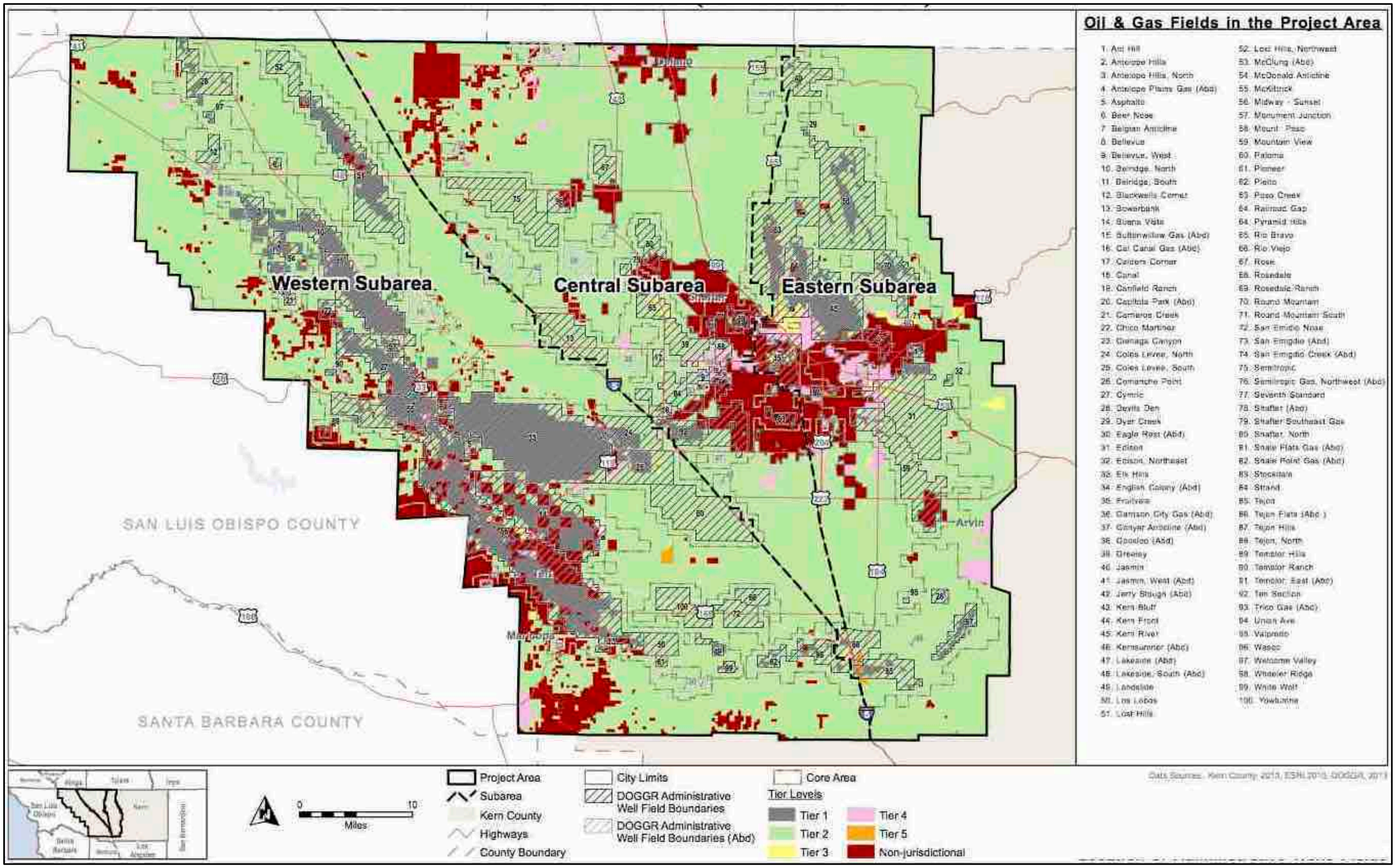

Figure 1-2: Administrative Oilfields in the Project Area by Subarea and Oilfield Status (Active or Abandoned)

1.2 Project Setting

On November 9, 2015, the Kern County Board of Supervisors approved amendments to Title 19 of the Kern County Zoning Ordinance (Ordinance), Chapter 19.98 (Oil and Gas Production) and related sections of the Ordinance to address oil and gas exploration and operation activities within the project area in greater detail. The Board of Supervisors also certified an 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 CEQA. As discussed in more detail in Section 1.5, below, the previously approved Ordinance amendments and certified EIR were directed to be set aside on March 26, 2020, pursuant to an opinion issued by the 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.” The County is preparing this SREIR to provide analysis addressing the CEQA deficiencies found by the Appellate Court decision. The Draft SREIR will 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.

Although the project area encompasses 3,700 square miles, the proposed project includes only unincorporated County land. Therefore, the Project 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 Project 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 Bureau of Land Management, U.S. Fish and Wildlife Service, and the California State Lands Commission, are also included within the 3,700-square-mile project area but are excluded from the Project impact analysis. Ancillary equipment and land uses (e.g., pipelines and access roads on unincorporated County lands) are included in the project area and 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).The Project impact analysis conservatively assumes that all new well activities in Kern County would occur within the portion of the project area subject to the County’s jurisdiction. Non-jurisdictional portions of the project area are included as part of the cumulative Project impact analysis.

To facilitate detailed analysis, the Project impact analysis divides the project area into three Project Subareas, the Western Subarea, the Central Subarea and the Eastern Subarea, which generally reflect major transportation corridors. The locations of the three Project Subareas are shown on **Figure 1-3 (Project Subareas)**.

The Western Subarea consists of 1,714 square miles (1,096,842 acres) and is generally bounded by the Kern County border on the north and west, Los Padres National Forest on the south, and Interstate 5 on the east. The Western Subarea contains many of the large-scale oil and gas extraction-level operations in the project area and includes 37 active oil and gas fields. Five of these oil and gas fields are the largest in California by production volume. The Western Subarea also includes dispersed agricultural operations and unincorporated areas around the cities of Taft and Maricopa.

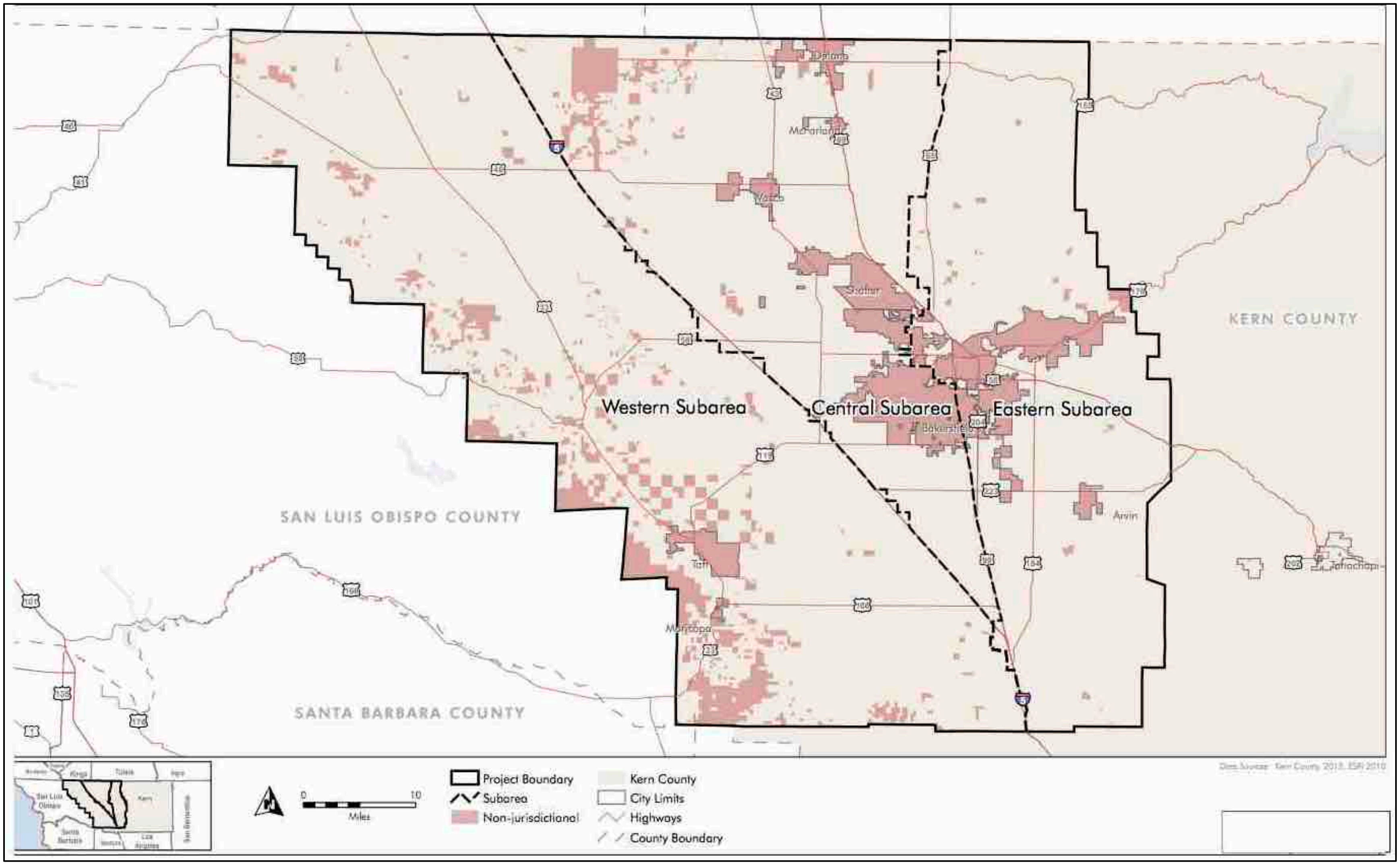

Figure 1-3: Project Subareas

The Central Subarea consists of 1,025 square miles (656,003 acres) and is generally bounded by the Kern County border on the north, Interstate 5 on the west, and State Routes 65 and 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.

The Eastern Subarea consists of 953 square miles (609,889 acres) and is generally bounded by the County border on the north, State Routes 65 and 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. The Eastern Subarea includes parts of the unincorporated Metropolitan Bakersfield area and unincorporated areas around the city of Arvin.

Kern County is the largest oil-producing county in the state. In 2012, 43,000 active oil and gas, dry gas, and gas storage wells, 78% of all active wells in California, were located in Kern County. In addition, 80% of all oil and natural gas produced in California came from wells in Kern County. The first commercially developed oilfield in Kern County was the McKittrick Field, which was developed in 1898. Development was facilitated by the presence 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 had produced almost 17 million barrels of oil from the Kern River Field. In the mid-1930s, several 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 the Ten Section, Greeley, Rio Bravo, North Coles Levee, South Coles Levee, and Strand oil fields.

1.3 Project Description

The proposed project consists of the reconsideration of amendments to Title 19 of the Kern County Zoning Ordinance, Chapter 19.98 (Oil and Gas Production) and related sections of the Ordinance, and the implementation of future oil and gas development activities expected to be undertaken pursuant to the amended Ordinance. In January 2013, the California Independent Petroleum Association, Independent Oil Producers Agency and the Western States Petroleum Association (the "Project Proponents") requested that the County consider amending the Ordinance to address oil and gas exploration and operation activities within the project area in greater detail. Under Chapter 19.112 of the Ordinance, amendments to the text of the Zoning Title of the Ordinance can only be initiated by the Kern County Board of Supervisors. On November 9, 2015, the County certified an EIR for the Project and approved the Ordinance amendments. As discussed in more detail in Section 1.5, below, the previously approved Ordinance amendments and certified EIR were directed to be set aside, effective March 26, 2020, pursuant to an Appellate Court opinion issued on February 25, 2020.

The proposed project would amend the Zoning Ordinance to focus on local permitting for oil and gas exploration and operation activities within the project area 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 primary changes that would be made to the Zoning Ordinance if the proposed project is approved by the County are as follows:

a) Chapter 19.98 of the Ordinance would be comprehensively overhauled 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 that all new oil and gas wells for exploration or production obtain approval from the Kern County Natural Resources and Planning Department prior to commencing drilling.

b) A Tier System would be incorporated into Chapter 19.98 of the Ordinance to address the different land uses and zone districts where oil and gas activities occur. The Tier System would be made up of five distinct Tiers, including Tier 1, areas primarily consisting of existing oil and gas activities; Tier 2, areas primarily consisting of existing agricultural activities; Tier 3, areas primarily consisting of existing industrial development; Tier 4, areas primarily consisting of existing urban development in which oil and gas activities require a conditional use permit, and Tier 5 areas consisting of existing and future adopted Specific Plans. The locations of the Tier areas that would be added to the Ordinance are shown in **Figure 1-4 (Oil and Gas Activity Tiers 1–5 Locations)**.

c) An Oil and Gas Conformity Review would be required as part of the “Drilling by Ministerial Permit” Section that would be added to the Ordinance in the proposed amendments to allow for comprehensive review of all drilling activities. The review would require consistent, comprehensive mitigation based on defined Tiers of surrounding land uses, as would be specified in the amended Ordinance and in the Mitigation, Monitoring, and Reporting Plan (MMRP) that would be adopted with the proposed amendments. An application package would be submitted to the County that includes a site plan and written documentation ensuring compliance with all applicable development and implementation standards and conditions, including the MMRP.

d) A Minor Activity Review would be required as part of the “Drilling by Ministerial Permit” section that would be added to the Ordinance in the proposed amendments to allow for comprehensive review of minor oil and gas activities. The review would require consistent, comprehensive mitigation based on defined Tiers of surrounding land uses, as would be specified in the amended Ordinance and in the MMRP. An application package would be submitted with written documentation ensuring compliance with all applicable Development and Implementation Standards and Conditions, including the MMRP.

e). The Development and Implementation Standards and Conditions section of the Ordinance would be updated by the proposed amendments to require compliance with all applicable mitigation measures in the MMRP and additional regulatory requirements. Some of the new standards would include setbacks from sensitive receptors, reductions in the 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.

f). For all Oil and Gas Conformity Review Site Plans submitted to the County, an applicant would be required to submit a signature block and statement as part of the application package. The signature block would provide for the signatures of the applicant and, if different, the Mineral Owner of the land subject to a proposed Site Plan. In addition, for activities occurring on split estate lands, where the Land/Surface Owner is different from the Mineral Owner, the signature block would 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 would take place within seven business days. If the County finds the application to be incomplete and requests additional information, a second review would take place within three business days upon receipt of the requested information.

g). The proposed Ordinance amendments also include 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 would 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 would be processed within seven days. However, applications would 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 Ordinance would be updated by the proposed amendments to ensure consistency with the MMRP and other regulatory requirements. 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.

The Project impact analysis conservatively assumes that over a 25-year planning horizon an average of 2,697 new producing wells per year could be drilled in the project area and subject to permitting under the amended Ordinance. 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. "Producing wells" refers to oil and gas, dry gas, dry hole, and liquid petroleum gas wells. Each well drilled may be associated with a number of other oil and gas activities. For purposes of the Project impact analysis, oil and gas activities are divided into two sets of components: (1) construction activities, which may include but are not limited to geophysical surveys, access road and well pad construction, drilling, well completion and testing, distribution line construction, well re-working and workovers, well decommissioning, and well abandonment; and (2) operational activities, which may include but are not limited to geophysical monitoring, produced fluids and natural gas treatment, water management, well stimulation treatment, enhanced oil recovery activities, and water and waste gas injection via injection well.

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. 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.

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 are integral components 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 oil and water, 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.

Extraction technologies include injecting large volumes of water (water flooding) or steam (steam flooding and cyclic steam injection) 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 on site, especially at larger oilfields.

1.4 Project 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 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 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, which ensures 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 (BMPs), 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 and implementation of clean air strategies to address existing air quality issues, and the promotion 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.

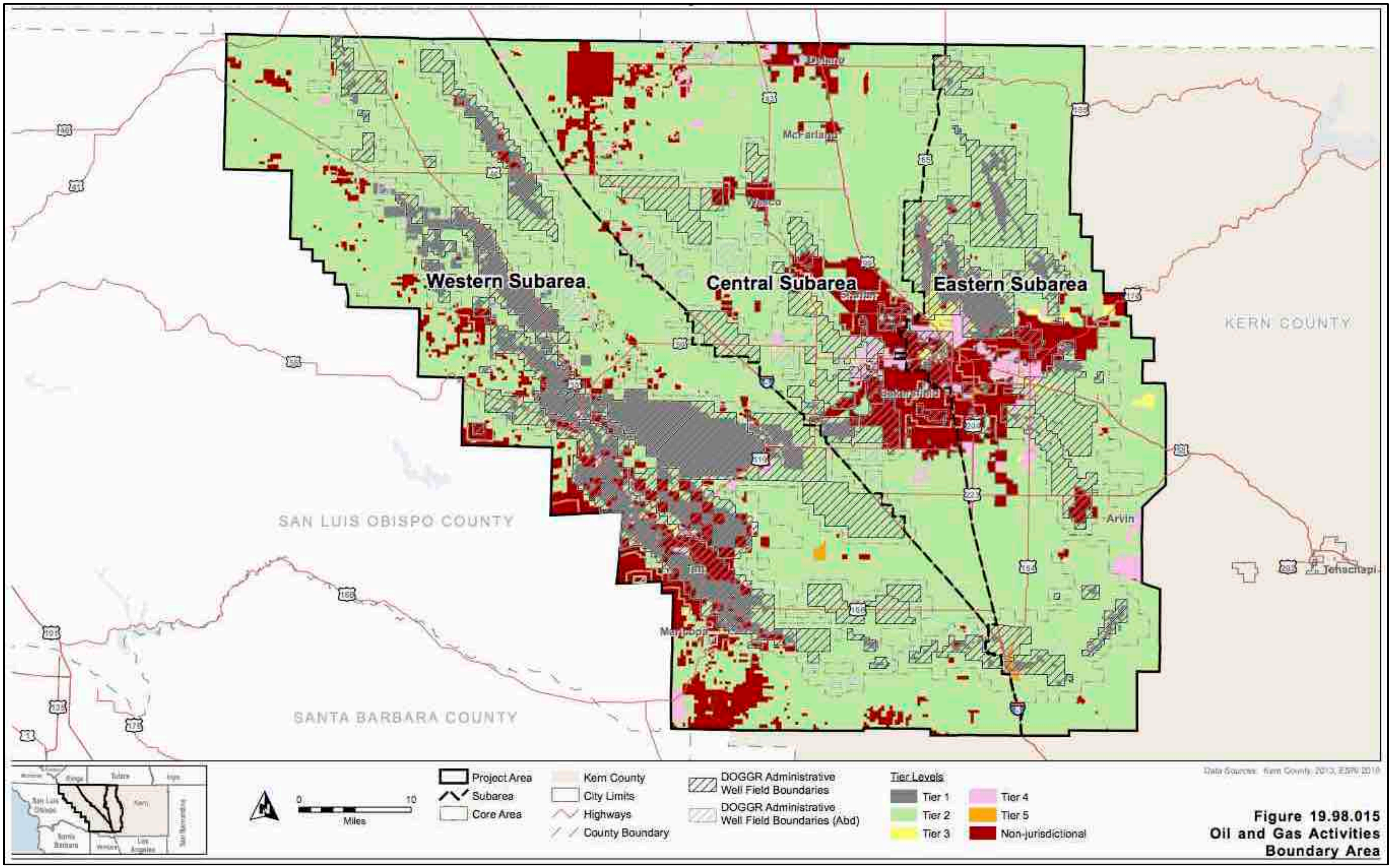

Figure 1-4: Oil and Gas Activity Tiers 1–5 Locations

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 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 upon 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 SREIR Purpose

The purpose of the SREIR is to provide analysis to address the five CEQA deficiencies in the Project's EIR 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 EIR on November 9, 2015. 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 except 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 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 EIR except for "five areas in which the EIR did not comply with CEQA: (1) mitigation of water supply impacts; (2) impacts from $PM_{2.5}$ 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 EIR. 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 EIR identified by the Appellate Court:

(1) <u>Mitigation of water supply impacts</u>. Consistent with the opinion, the SREIR will consider feasible revisions to water supply Mitigation Measures 4.17-2 to 4.17-4 in the EIR, 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 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 update the analysis of potential Project impacts from $PM_{2.5}$ emissions, 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 Mitigation Measure 4.2-1 of the EIR. 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 EIR 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 Project-related 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 EIR 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.

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2. Kern County Environmental Checklist Form

2.1 Environmental Factors Potentially Affected

The environmental factors checked below would be potentially affected by this project, involving at least one impact that is a "Potentially Significant Impact," as indicated by the checklist on the following pages.

☐ Aesthetics	☒ Agriculture / Forestry Resources	☒ Air Quality
☐ Biological Resources	☐ Culture Resources	☐ Energy
☐ Geology / Soils	☐ Greenhouse Gas Emissions	☐ Hazards and Hazardous Materials
☒ Hydrology / Water Quality	☐ Land Use / Planning	☐ Mineral Resources
☒ Noise	☐ Population / Housing	☐ Public Services
☐ Recreation	☐ Transportation	☐ Tribal Cultural Resources
☒ Utilities / Service Systems	☐ Wildfire	☐ Mandatory Findings of Significance

2.2 Determination

On the basis of this initial evaluation:

☐ I find that the proposed project COULD NOT have a significant effect on the environment, and a NEGATIVE DECLARATION will be prepared.

☐ I find that although the proposed project could have a significant effect on the environment, there will not be a significant effect in this case because revisions in the project have been made by or agreed to by the project proponent. A MITIGATED NEGATIVE DECLARATION will be prepared.

☐ I find that the proposed project MAY have a significant effect on the environment, and an ENVIRONMENTAL IMPACT REPORT is required.

☒ I find that the proposed project MAY have a "potentially significant impact" or "potentially significant unless mitigated" impact on the environment, but at least one effect 1) has been adequately analyzed in an earlier document pursuant to applicable legal standards, and 2) has been addressed by mitigation measures based on the earlier analysis as described on attached sheets. An ENVIRONMENTAL IMPACT REPORT is required, but it must analyze only the effects that remain to be addressed.

☐ I find that although the proposed project could have a significant effect on the environment, because all potentially significant effects (a) have been analyzed adequately in an earlier EIR or NEGATIVE DECLARATION pursuant to applicable standards, and (b) have been avoided or mitigated pursuant to that earlier EIR or NEGATIVE DECLARATION, including revisions or mitigation measures that are imposed upon the proposed project, nothing further is required.

Cindi L. Hoover	April 29, 2020
Signature	Date
Cindi L. Hoover	Kern County Planning & Natural Resources
Printed Name	For

3. Evaluation of Environmental Impacts

1. A brief explanation is required for all answers except “No Impact” answers that are adequately supported by the information sources a lead agency cites in the parentheses following each question. A “No Impact” answer is adequately supported if the referenced information sources show that the impact simply does not apply to projects like the one involved (e.g., the project falls outside a fault rupture zone). A “No Impact” answer should be explained where it is based on project-specific factors, as well as general standards (e.g., the project would not expose sensitive receptors to pollutants, based on a project-specific screening analysis).

2. All answers must take account of the whole action involved, including off-site as well as on site, cumulative as well as project-level, indirect as well as direct, and construction as well as operational impacts.

3. Once the lead agency has determined that a particular physical impact may occur, then the checklist answers must indicate whether the impact is potentially significant, less than significant with mitigation, or less than significant. “Potentially Significant Impact” is appropriate if there is substantial evidence that an effect may be significant. If there are one or more “Potentially Significant Impact” entries when the determination is made, an EIR is required.

4. “Negative Declaration: Less Than Significant With Mitigation Incorporated” applies where the incorporation of mitigation measures has reduced an effect from “Potentially Significant Impact” to a “Less Than Significant Impact.” The lead agency must describe the mitigation measures, and briefly explain how they reduce the effect to a less than significant level.

5. Earlier analyses may be used where, pursuant to the tiering, program EIR, or other CEQA process, an effect has been adequately analyzed in an earlier EIR or negative declaration. Section 15063(c)(3)(D). In this case, a brief discussion should identify the following:

   a. Earlier Analyses Used. Identify and state where they are available for review.

   b. Impacts Adequately Addressed. Identify which effects from the above checklist were within the scope of and adequately analyzed in an earlier document pursuant to applicable legal standards, and state whether such effects were addressed by mitigation measures based on the earlier analysis.

   c. Mitigation Measures. For effects that are “Less than Significant with Mitigation Measures Incorporated,” describe the mitigation measures which were incorporated or refined from the earlier document and the extent to which they address site-specific conditions for the project.

6. Lead agencies are encouraged to incorporate into the checklist references to information sources for potential impacts (e.g., general plans, zoning ordinances). Reference to a previously prepared or outside document should, where appropriate, include a reference to the page or pages where the statement is substantiated.

7. Supporting Information Sources: A source list should be attached, and other sources used or individuals contacted should be cited in the discussion.

8. This is only a suggested form, and lead agencies are free to use different formats; however, lead agencies should normally address the questions from this checklist that are relevant to a project’s environmental effects in whatever format is selected.

9. The explanation of each issue should identify:

   a. the significance criteria or threshold, if any, used to evaluate each question; and

   b. the mitigation measure identified, if any, to reduce the impact to less than significance.

Issues	Potentially Significant Impact	Less Than Significant With Mitigation Incorporated	Less Than Significant Impact	No Impact
II. AGRICULTURE AND FOREST RESOURCES. Would the project:				
a) 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 nonagricultural use?	☒	☐	☐	☐
b) Conflict with existing zoning for agricultural use, or Williamson Act contract?	☐	☐	☒	☐
c) Conflict with existing zoning for, or cause rezoning of, forest land (as defined in Public Resources Code section 12220(g)) or timberland (as defined in Public Resources Code section 4526) or timberland zoned Timberland Production (as defined by Government Code Section 51104 (g),	☐	☐	☒	☐
d) Result in the loss of forest land or conversion of forest land to non-forest use?	☐	☐	☒	☐
e) Involve other changes in the existing environment which, due to their location or nature, could result in conversion of Farmland to nonagricultural use or conversion of forest land to non-forest use?	☐	☒	☐	☐
f) 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?	☐	☐	☒	☐

Discussion:

(a) The EIR found that the Project has the potential to convert prime farmland, unique farmland, or farmland of statewide importance to non-agricultural use. This impact would be significant without mitigation. The EIR found that with the implementation of Mitigation Measure 4.2-1, which includes the use of agricultural conservation easements to compensate for Project farmland conversion, impacts would be less than significant. The Appellate Court determined that agricultural conservation easements do not mitigate farmland conversion impacts. Consistent with the opinion, the SREIR will consider other feasible mitigation measures to reduce the Project's farmland conversion impacts. The SREIR will consider whether farmland baseline conditions should be updated.

(b)–(d) The EIR determined that the Project would have less than significant or no impacts on forestry resources, agricultural zoning, and Williamson Act contracts.

(e) The EIR found that although Kern County Zoning considers oil and gas operations to be compatible with agriculture, the Project could result in other changes in the existing environment that could result in farmland conversion. These impacts would be reduced to less than significant levels with the implementation of Mitigation Measure 4.2-2, which does not include agricultural conservation easements.

(f) The EIR determined that the Project would have no impacts on the cancellation of California Land Conservation Act or Farmland Security Zone contracts. The SREIR is focused on analysis of the five specific CEQA topics identified by the court. None of the five CEQA topics include the EIR analysis of California Land Conservation Act and Farmland Security Zone contracts

Issues	Potentially Significant Impact	Less Than Significant With Mitigation Incorporated	Less Than Significant Impact	No Impact

III. AIR QUALITY. Where available, the significance criteria established by the applicable air quality management district or air pollution control district may be relied upon to make the following determinations. Would the project:

Issues	Potentially Significant Impact	Less Than Significant With Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Conflict with or obstruct implementation of the applicable air quality plan?	☒	☐	☐	☐
b) 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, would implementation of the project exceed any of the following adopted thresholds: i. San Joaquin Valley Unified Air Pollution Control District: <u>Operational and Area Sources</u> 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. <u>Stationary Sources as determined by District Rules</u> Severe Nonattainment 25 tons per year. Extreme Nonattainment 10 tons per year. ii. Eastern Kern Air Pollution Control District: <u>Operational and Area Sources</u> Reactive Organic Gases (ROG) 25 tons per year. Oxides of nitrogen (NO_X) 25 tons per year. Particulate Matter (PM_{10}) 15 tons per year. <u>Stationary Sources - determined by District Rules</u> 25 tons per year.	☒	☐	☐	☐
c) Expose sensitive receptors to substantial pollutant concentrations?	☒	☐	☐	☐
d) Result in other emissions (such as those leading to odors) adversely affecting a substantial number of people?	☒	☐	☐	☐

Discussion:

(a) The Project is located in the San Joaquin Valley Air Pollution Control District (SJVAPCD or District). The EIR found that, without mitigation, the Project has the potential to conflict with or obstruct implementation of applicable air quality plans. The implementation of Mitigation Measures 4.3-1 to 4.3-4 was found to reduce these impacts to less than significant levels. The SREIR is focused on correcting the five specific CEQA topics in the EIR identified by the Appellate Court. There was no deficiency in the EIR analysis of reactive organic gases (ROG), oxides of nitrogen (NOx), respiratory particulate matter (PM_{10}), or fine particulate matter ($PM_{2.5}$).

(b) The Project is located within the SJVAPCD. The EIR found that, without mitigation, the Project has the potential to 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 or to violate any air quality standard. Even with implementation of Mitigation Measures 4.3-1 to 4.3-4, and 4.3-8, the EIR found these impacts to be significant and unavoidable. The SREIR is focused on correcting the five specific CEQA topics in the EIR identified by the Appellate Court. There was no deficiency in the EIR analysis of ROG, NO_X, PM_{10}, or $PM_{2.5}$.

The Appellate Court opinion only found fault with the discussion of potential mitigation for the significant $PM_{2.5}$ emissions from the project, including Mitigation Measure 4.3-8, as it related to $PM_{2.5}$. The court determined that an analysis of how Mitigation Measure 4.3-8 proposed to mitigate the significant effects on the environment of the project's $PM_{2.5}$ emissions was necessary. Consistent with the opinion, the SREIR will update the analysis of potential Project impacts from $PM_{2.5}$ emissions, consider feasible mitigation measures for reducing potentially significant impacts, and, if applicable, discuss whether such impacts can be feasibly mitigated. The analysis will also provide updated information concerning the project area's air quality attainment status for $PM_{2.5}$ emissions.

(c) The EIR found that, without mitigation, the Project has the potential to expose sensitive receptors to substantial pollutant concentrations. The implementation of Mitigation Measures 4.3-5 and 4.3-6 was found to reduce these impacts to less than significant levels. The Appellate Court opinion concluded that separate mitigation and supporting analysis for potential $PM_{2.5}$ emission impacts was required in the EIR. In addition, the opinion determined that a Multi-Well Health Risk Assessment prepared for the Project should have been circulated for public review and comment prior to the certification of the EIR. The SREIR will update the analysis of potential Project impacts from $PM_{2.5}$ emissions, including the potential exposure of sensitive receptors to substantial $PM_{2.5}$ concentrations, consider feasible mitigation measures for reducing potentially significant impacts, and, if applicable, discuss whether such impacts can be feasibly mitigated. The SREIR will include a Multi-Well Health Risk Assessment for public review and comment, and will reflect updated information about $PM_{2.5}$ emissions in Kern County, as applicable.

(d) The EIR found that, without mitigation, the Project has the potential to create objectionable odors that affect a substantial number of people. The EIR found that this impact would remain significant and unavoidable even with implementation of Mitigation Measure 4.3-7. The SREIR is focused on analysis of the five specific CEQA topics identified by the court. None of the five CEQA topics include the EIR analysis of objectionable odors that affect a substantial number of people.

Issues	Potentially Significant Impact	Less Than Significant With Mitigation Incorporated	Less Than Significant Impact	No Impact
X. HYDROLOGY AND WATER QUALITY. Would the project:				
a) Violate any water quality standards or waste discharge requirements or otherwise substantially degrade surface or ground water quality ?	☐	☒	☐	☐
b) Substantially decrease groundwater supplies or interfere substantially with groundwater recharge such that the project may impede sustainable groundwater management of the basin?	☒	☐	☐	☐
c) 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?	☐	☒	☐	☐
d) In flood hazard, tsunami, seiche zones, risk release of pollutants due to project inundation?	☐	☐	☐	☒
e) Conflict with or obstruct implementation of a water quality control plan or sustainable groundwater management plan?	☒	☐	☐	☐

Discussion:

(a) The EIR found that, without mitigation, the Project has the potential to violate water quality standards or waste discharge requirements. The implementation of Mitigation Measures 4.9-1 to 4.9-6 was found to reduce these impacts to less than significant levels. The SREIR is focused on analysis of the five specific CEQA topics identified by the court. None of the five CEQA topics include the EIR analysis of impacts to water quality standards or waste discharge requirements.

(b) The Draft EIR projected that the Project would result in a slight increase in total regional water demand, including groundwater, and found that this increase would have a significant water supply impact. The Final EIR concluded that, based on updated water supply analysis, the Project was projected to slightly reduce total regional water demand, but continued to consider the impact significant due to uncertainties affecting the projected reduction. The EIR included Mitigation Measures 4.17-2 to 4.17-4 to reduce water supply impacts by such means as using produced water from oil and gas activities for irrigation or other uses, which would increase regional water supplies. The EIR found that the Project's water supply impacts, including to groundwater, would remain significant and unavoidable with the implementation of these mitigation measures. The court determined that the effect of these mitigation measures was uncertain and the water supply significance finding was not adequately supported. The SREIR will consider feasible revisions to Mitigation Measures 4.17-2 to 4.17-4, or new feasible measures, that could reduce the Project's impacts on regional water supplies, including groundwater, with more certainty. The SREIR analysis of regional water supply impacts will be brought up to date and will include available information developed in conjunction with the implementation of the Sustainable Groundwater Management Act (SGMA) in the Project Area.

(c) The EIR found that with the implementation of Mitigation Measures 4.9-1 to 4.9-6, the Project would have a less than significant impact related to the alteration of a stream or river, or from adding impervious surfaces that would result in substantial erosion or siltation on or off site; substantially increase the rate of amount of surface runoff and cause flooding on or off site; create or contribute runoff water that would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff; or impede or redirect flood flows. The SREIR is focused on analysis of the five specific CEQA topics identified by the court. None of the five CEQA topics include the EIR analysis of impacts related to the alteration of a stream or river, or from adding impervious surfaces that would result in substantial erosion or siltation on or off site; substantially increase the rate of amount of surface runoff and cause flooding on or off site; create or contribute runoff water that would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff; or impede or redirect flood flows.

(d) The EIR found that the Project would cause no impacts from inundation and risk of pollutant releases due to inundation in a flood hazard, tsunami, or seiche zone. The SREIR is focused on analysis of the five specific CEQA topics identified by the court. None of the five CEQA topics include the EIR analysis of inundation and risk of pollutant releases due to inundation in a flood hazard, tsunami, or seiche zone.

(e) The SREIR is focused on analysis for the five specific CEQA deficiencies in the EIR identified by the Appellate Court. None of the five CEQA topics include the EIR analysis of potential conflicts with the implementation of a water quality control plan. As discussed in subparagraph X.(b), above, the EIR projected that the Project would result in a slight increase in total regional water demand, including groundwater, and found that this increase would have a significant water supply impact. The Appellate Court determined that the EIR include updated information concerning the implementation of the SGMA, including the adoption of sustainable groundwater management plans in the project area. The SREIR will be brought up to date and include available information developed in conjunction with the implementation of the SGMA in the project area and consider potential impacts related to such plans.

Issues	Potentially Significant Impact	Less Than Significant With Mitigation Incorporated	Less Than Significant Impact	No Impact
XIII. NOISE. Would the project result in:				
a) 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?	☒	☐	☐	☐
b) Generation of excessive groundborne vibration or groundborne noise levels?	☐	☐	☐	☒
c) A substantial permanent increase in ambient noise levels in the project vicinity above levels existing without the project?	☐	☒	☐	☐
d) For a project located within the Kern County Airport Land Use Compatibility Plan, would the project expose people residing or working in the project area to excessive noise levels?	☐	☐	☐	☒

Discussion:

(a) The EIR found that, without mitigation, the Project has the potential to generate 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. The implementation of Mitigation Measures 4.12-1 to 4.12-2 was found to reduce these impacts to less than significant levels. The SREIR is focused on analysis of the five specific CEQA topics identified by the court. None of the five CEQA topics include the EIR analysis of permanent or temporary noise impacts in excess of standards established in County general plan or noise ordinance, or applicable standards of other agencies. The Appellate Court opinion determined that an analysis of the magnitude of increases in ambient noise attributable to the Project was required in the EIR. The SREIR will analyze potential Project impacts from the magnitude of increases in ambient noise levels, determine whether that magnitude of increase is or is not significant, and, if applicable, consider feasible mitigation measures for reducing potentially significant impacts, and, if applicable, discuss whether such impacts can be feasibly mitigated. The SREIR will also consider whether the description of project area ambient noise baseline conditions require updating.

(b) The EIR found that the Project will not generate or expose persons to excessive groundborne vibration or groundborne noise levels. The SREIR is focused on analysis of the five specific CEQA topics identified by the court. None of the five CEQA topics include the EIR analysis of groundborne vibration or groundborne noise levels.

(c) The EIR found that, without mitigation, the Project has the potential to generate 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

7. Conclusion of Consultation: Consultation with a tribe shall be considered concluded when either of the following occurs:

a. The parties agree to measures to mitigate or avoid a significant effect, if a significant effect exists, on a tribal cultural resource; or

b. A party, acting in good faith and after reasonable effort, concludes that mutual agreement cannot be reached. (Pub. Resources Code §21080.3.2 (b)).

8. Recommending Mitigation Measures Agreed Upon in Consultation in the Environmental Document: Any mitigation measures agreed upon in the consultation conducted pursuant to Public Resources Code §21080.3.2 shall be recommended for inclusion in the environmental document and in an adopted mitigation monitoring and reporting program, if determined to avoid or lessen the impact pursuant to Public Resources Code §21082.3, subdivision (b), paragraph 2, and shall be fully enforceable. (Pub. Resources Code §21082.3 (a)).

9. Required Consideration of Feasible Mitigation: If mitigation measures recommended by the staff of the lead agency as a result of the consultation process are not included in the environmental document or if there are no agreed upon mitigation measures at the conclusion of consultation, or if consultation does not occur, and if substantial evidence demonstrates that a project will cause a significant effect to a tribal cultural resource, the lead agency shall consider feasible mitigation pursuant to Public Resources Code §21084.3 (b). (Pub. Resources Code §21082.3 (e)).

10. Examples of Mitigation Measures That, If Feasible, May Be Considered to Avoid or Minimize Significant Adverse Impacts to Tribal Cultural Resources:

a. Avoidance and preservation of the resources in place, including, but not limited to:

i. Planning and construction to avoid the resources and protect the cultural and natural context.

ii. Planning greenspace, parks, or other open space, to incorporate the resources with culturally appropriate protection and management criteria.

b. Treating the resource with culturally appropriate dignity, taking into account the tribal cultural values and meaning of the resource, including, but not limited to, the following:

i. Protecting the cultural character and integrity of the resource.

ii. Protecting the traditional use of the resource.

iii. Protecting the confidentiality of the resource.

c. Permanent conservation easements or other interests in real property, with culturally appropriate management criteria for the purposes of preserving or utilizing the resources or places.

d. Protecting the resource. (Pub. Resource Code §21084.3 (b)).

e. Please note that a federally recognized California Native American tribe or a non-federally recognized California Native American tribe that is on the contact list maintained by the NAHC to protect a California prehistoric, archaeological, cultural, spiritual, or ceremonial place may acquire and hold conservation easements if the conservation easement is voluntarily conveyed. (Civ. Code §815.3 (c)).

f. Please note that it is the policy of the state that Native American remains and associated grave artifacts shall be repatriated. (Pub. Resources Code §5097.991).

11. Prerequisites for Certifying an Environmental Impact Report or Adopting a Mitigated Negative Declaration or Negative Declaration with a Significant Impact on an Identified Tribal Cultural Resource: An Environmental Impact Report may not be certified, nor may a mitigated negative declaration or a negative declaration be adopted unless one of the following occurs:

a. The consultation process between the tribes and the lead agency has occurred as provided in Public Resources Code §21080.3.1 and §21080.3.2 and concluded pursuant to Public Resources Code §21080.3.2.

b. The tribe that requested consultation failed to provide comments to the lead agency or otherwise failed to engage in the consultation process.

c. The lead agency provided notice of the project to the tribe in compliance with Public Resources Code §21080.3.1 (d) and the tribe failed to request consultation within 30 days. (Pub. Resources Code §21082.3 (d)).

agencies. The implementation of Mitigation Measures 4.12-1 to 4.12-2 was found to reduce these impacts to less than significant levels. The SREIR is focused on analysis of the five specific CEQA topics identified by the court. None of the five CEQA topics include the EIR analysis of permanent or temporary noise impacts in excess of standards established in County general plan or noise ordinance, or applicable standards of other agencies. The Appellate Court opinion determined that an analysis of the magnitude of increases in ambient noise attributable to the Project was required in the EIR. The SREIR will analyze potential Project impacts from the magnitude of increases in ambient noise levels; determine whether that magnitude of increase is or is not significant; if applicable, consider feasible mitigation measures for reducing potentially significant impacts; and discuss whether such impacts can be feasibly mitigated. The SREIR will also consider whether the description of project area ambient noise baseline conditions requires updating.

(d) The Project EIR found that, without mitigation, the Project has the potential to expose people in the project area that reside or work within an airport land use compatibility plan area, or in the vicinity of an airport, to excessive noise levels. The implementation of Mitigation Measures 4.12-1 to 4.12-2 was found to reduce these impacts to less than significant levels. The SREIR is focused on analysis of the five specific CEQA topics identified by the court. None of the five CEQA topics include the EIR analysis of the exposure of people in the project area that reside or work within an airport land use compatibility plan area, or in the vicinity of an airport, to excessive noise levels.

Issues	Potentially Significant Impact	Less Than Significant With Mitigation Incorporated	Less Than Significant Impact	No Impact
XIX. UTILITIES AND SERVICE SYSTEMS. Would the project result in:				
a) 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?	☒	☐	☐	☐
b) Have sufficient water supplies available to serve the project and reasonably foreseeable future development during normal, dry and multiple dry years?	☒	☐	☐	☐
c) 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?	☐	☐	☐	☒
d) 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?	☐	☐	☐	☒
e) Comply with federal, State, and local management and reduction statutes and regulations related to solid waste?	☐	☐	☐	☒

Discussion:

(a) The EIR found that the Project would not significantly impact storm water drainage facilities and that potentially significant impacts to wastewater facilities and treatment capacity would be mitigated to less than significant levels with the implementation of Mitigation Measure 4.17-1. The SREIR is focused on correcting the five specific CEQA topics in the EIR identified by the Appellate Court. None of the five CEQA topics include the EIR analysis of wastewater, storm water, electric power, natural gas, or telecommunications. As discussed below, the EIR found that water supply impacts would remain significant and unavoidable with the implementation of Mitigation Measures 4.17-2 to 4.17-4. The Appellate Court determined that the effect of these mitigation measures was uncertain and that this significance finding was not adequately supported. Consistent with the opinion, the SREIR will consider feasible revisions to Mitigation Measures 4.17-2 to 4.17-4, or new feasible measures, that could reduce the Project’s impacts on regional water supplies with more certainty. The SREIR will consider the extent to which revised or new water supply mitigation measures may require the construction or relocation of new or expanded water facilities that could cause significant environmental effects.

(b) The EIR projected that the Project would result in a slight increase in total regional water demand and found that this increase would have a significant water supply impact. The EIR included Mitigation Measures 4.17-2 to 4.17-4 to reduce water supply impacts by such means as using produced water from oil and gas activities for irrigation or other uses, which would increase regional water supplies. The EIR found that the Project's water supply impacts would remain significant and unavoidable with the implementation of these mitigation measures. The Appellate Court determined that the effect of these mitigation measures was uncertain and the water supply significance finding was not adequately supported. Consistent with the opinion, the SREIR will consider feasible revisions to Mitigation Measures 4.17-2 to 4.17-4, or new feasible measures that could reduce the Project's impacts on regional water supplies with more certainty, including the additional use of oil and gas produced water to meet regional irrigation or other water demands. The SREIR analysis of regional water supply impacts will be brought up to date and include available information developed in conjunction with the implementation of the SGMA in the project area as discussed in the opinion.

(c)/(e) The EIR found that the Project has the potential to fail to comply with federal, state, and local solid waste statutes, regulations and standards and could exceed the capacity of local infrastructure. The implementation of Mitigation Measures 4.17-2, 4.17-3, and 4.17-5 was found to reduce these impacts to less than significant levels. The SREIR is focused on correcting the five specific CEQA topics in the EIR identified by the Appellate Court. None of the five CEQA topics include the EIR analysis of solid waste impacts.

AGENDA

KERN COUNTY PLANNING AND NATURAL RESOURCES DEPARTMENT

Scoping Meeting

Microsoft Live Event
https://tinyurl.com/y93r92b3

May 13, 2020 – 1:30 p.m.

Pursuant to revised Section 21083.9 of the Public Resources Code, California Environmental Quality Act, effective January 1, 2002, this scoping meeting is being held to receive agency comments on the preparation of Environmental Impact Reports (EIR) on certain projects. In compliance with the Governor's Executive Order, the California Department of Public Health's guidelines on gatherings regarding COVID-19, and Kern County Local Emergency Declaration, the scoping meeting required by the California Environmental Quality Act will be conducted online utilizing Microsoft Live Events. The process of determining the scope, focus, and content of the EIR is known as "scoping." Scoping helps to identify the range of actions, alternatives, environmental effects, methods of assessment, and mitigation measures to be analyzed in depth, and eliminate from detailed study those issues that are not important to the decision at hand. This is not a public hearing, however the public may be present and offer comments. If you attend as a member of the public to address an item on the agenda, please let the chairperson know, when discussion begins on that item. Each project will be presented by staff followed by an opportunity for comments for the record.

A. INTRODUCTION: Staff

B. NEW CASES:
EIR – Notice of Preparation:
Supplemental Recirculated Environmental Impact Report for Revisions to Title 19 - Kern County Zoning Ordinance (2020 A) Focused on Oil and Gas Local Permitting. (SCH # 2013081079)

C. ADJOURNMENT:

AMERICANS WITH DISABILITIES ACT
(Government Code Section 54953.2)

Disabled individuals who need special assistance to attend or participate in the scoping meeting may request assistance at the Kern County Planning Department or by calling Adrenne Lane-Price at (661) 862-8615. 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.

Posted: May 11, 2020
CLH

SUBMIT WRITTEN COMMENTS ON THE NOP BY MAY 29, 2020 AT 5PM
Mail to:
Kern County Planning and Natural Resources Department
Attn: Cindi Hoover
2700 'M' Street, Suite 100
Bakersfield, CA 93301
Phone: (661) 862-8629, **Email:** hooverc@kerncounty.com

Teams Live Event Scoping Meeting Instructions

Introduction: In compliance with the Governor's Executive Order, the California Department of Public Health's guidelines on gatherings regarding COVID-19, and Kern County Local Emergency Declaration, the scoping meeting required by the California Environmental Quality Act Guidelines will be conducted online utilizing Microsoft Live Events to allow Agencies and Interested Parties to comment on the preparation of the Draft Supplemental Environmental Impact Report for Revisions to the Kern County Zoning Ordinance for Oil and Gas Local Permitting.

If you are having trouble participating in the Microsoft Live Event please email Julie Williams at williamsj@kerncounty.com

Meeting Date and Time: Wednesday May 13, 2020 at 1:30 pm PST

Link to join: **https://tinyurl.com/y93r92b3**

Spanish Language Translation: Spanish language translation services will be provided in two ways.

Microsoft Live Events Closed Caption – Closed Captions are available in Spanish by clicking on the  at the bottom right of the Presentation Screen. To select Spanish language closed captioning click on the gear icon located next to the closed captioning icon as shown . The County of Kern cannot ensure the accuracy of translation through Microsoft's Live Event closed captioning service.

Live Interpretation via Conference Call – To listen to a Live Interpreter call (224) 501-3412, Access Code: 408-162-717. Attendees will need access to 2 devices to watch the Live Event and listen to the Live Interpretation. Live Interpretation will only be available for Staff's Presentation, no verbal comments will be received during the event therefore, the Live Interpreter will not have the ability to translate questions or comments from Attendees.

Participating in the Virtual Scoping Meeting

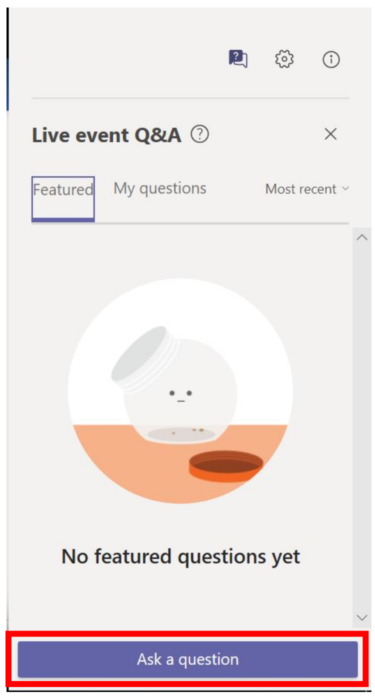
Participating: To join the Virtual Scoping Meeting paste the URL above into your web browser address bar. The URL will direct you to a Microsoft Teams Home Page that will give you the following 3 options: Download the Teams App; Sign-In using your Microsoft Log-In; Join Anonymously. Choose any of these options to join the meeting.

Please note the following:

- The time needed to download the Teams App may vary depending on a number of factors including your internet or data connection speed and the device memory capacity.
- If you have the Teams App already downloaded on your device the meeting will automatically open in your Teams App.
- If joining the meeting from a mobile device, Safari is not a supported browser. We recommend you use an internet connected computer for the best experience.
- For more information about supported browsers, device requirements and more, please visit the Microsoft Office article at the following link:

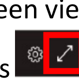
Commenting: Commenting on the scope of the Draft Supplemental Recirculated Environmental Impact Report can be accomplished by providing written comments to Cindi Hoover, Lead Planner, at hooverc@kerncounty.com or by mail at Kern County Planning and Natural Resources Department, 2700 "M" Street, Suite 100, Bakersfield, CA. 93301.

During the virtual Scoping Meeting, questions can be submitted via the Q&A tab (shown below) on the "Right Pane" of the Presentation Screen. The Q&A tab should also be used by Interested Parties and Agencies to submit, for the record, their participation and intent to provide written comments. No verbal comments will be accepted during the virtual Scoping Meeting.



FAQs

Q: I don't see the "Ask a Question" Button on the Presentation Screen, how do I ask a question?

A: The "Right Pane" where the Q&A panel is located may not be available in full screen viewing mode. To change from full screen viewing mode press either the Esc key or the minimize arrows  at the bottom right corner. Next click on the Q&A icon  at the top of the "Right Pane". The Q&A Panel should now open.

Q: Is there a limit to how long my question can be using the Q&A Panel?

A: Yes, a maximum of 2,400 characters per question are allowed by Microsoft.

Q: Are questions and comments anonymous?

A: Questions may be submitted anonymously or you may provide your name to show with the question. For more information on using the Q&A tool please visit the Office Support article at the following link:

Q: I keep getting a prompt to download the Microsoft Teams App, do I need to download the App?

A: If you are using a supported web browser such as Chrome, Firefox, or Edge you do not need to download the Microsoft Teams App. Please see the Microsoft Live Events support article at the following link for information about supported browsers, and device requirements.

> https://support.office.com/en-us/article/attend-a-live-event-in-teams-a1c7b989-ebb1-4479-b750-c86c9bc98d84

Q: If I already have the Microsoft Teams App downloaded on my device will the virtual Scoping Meeting Live Event open in my app?

A: Yes, if you have the app the event will open in your Teams App. Be sure you are using the Q&A panel in the "Right Pane" to ask questions or submit your name for the record and not the Teams Chat feature on the left of the screen.

Q: How can I provide verbal comments for the record?

A: While we recommend you provide written comments via the email or the mailing address below, verbal comments may be submitted by phone to Cindi Hoover, Lead Planner, at (661) 862-8629.

SUMMARY OF PROCEEDINGS

KERN COUNTY AGENCY SCOPING MEETING

Kern County Planning Department
2700 M Street, Suite 100
Bakersfield, California

Microsoft Live Event
https://tinyurl.com/y93r92b3

Date May 13, 2020

STAFF ATTENDANCE: Lorelei H Oviatt, AICP, Director
Cindi Hoover, Planner III
Louis Ramirez, Planner I

The meeting convened at 1:30 p.m. with Ms. Oviatt introducing Staff in attendance and outlining the purpose of the scoping meeting. Items were then discussed in order as identified on the agenda.

NOTICE OF PREPARATION PROJECT:

EIR – Notice of Preparation:
Supplemental Recirculated Environmental Impact Report for Revision to Title 19 - Kern County Zoning Ordinance (2020 A) Focused on Oil and Gas Local Permitting. (PP13284)

Ms. Oviatt provided instructions, verbally and with a PowerPoint presentation, for participating and submitting comments, introduced and described the proposed project, and asked if there were any questions. Spanish language translation was provided via closed captioning and a live translation call-in phone number.

The following comments/questions were submitted in writing via the Teams Live Event Q&A feature and answered by Ms. Oviatt verbally.

- Anonymous - Is there an estimated time frame when all the actions to complete the Oil & Gas Supplemental Recirculated EIR will be done?
- Answer – Our schedule currently has us taking this for reconsideration before the Board the first quarter of 2021.
- Anonymous - Who are the people on the panel working on the Oil & Gas Supplemental Recirculated EIR and how can we be part of the panel?
- Answer – There is no “panel” working on this EIR but like all projects (solar, industrial projects) there is an applicant who is funding the EIR and the applicant for this project is WSPA and CIPA. If you are in the oil and gas industry please contact your industry representatives. The County is writing this document, the County wrote the zoning ordinance, and the County is looking at the most protective mitigation and looking at what the court told us we needed to correct and working through that process. The applicant who is the technical expert, like in all projects , has interaction with Planning Department.
- Juan Flores (Center for Race Poverty and the Environment) - What are the mitigation options for water that the County is thinking of?
- Answer – We are not prepared to answer that question yet, we are still accepting scoping

comments.

- Juan Flores (Center for Race Poverty and the Environment) - 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?
- Answer – This is a scoping meeting, not a community meeting and the purpose for agencies and others interested in the environmental process. It is not a requirement but we have done as much as we can to allow people to participate. It is unclear what you mean by technological barriers, Planning Commission and Board of Supervisors can be called in to. We are doing everything we can to keep people safe during the Covid-19 pandemic and still ensure public participation. The Governor has suspended a variety of requirements which we agree with, the important thing is to keep people safe during the pandemic. If people would like to comment they may do so in writing, by email, or drop a letter in the mail. If people would like to collect names on a petition and provide those they may, there are many ways to participate.
- Anonymous - Has there been any new developments regarding split state surfaces and the 120 day process?
- Answer – There have not been any “new” developments regarding split estate process. That process was challenged in court and the court ruled in the County’s favor so at this point those requirements of the Zoning Ordinance are still valid. If the commenter has thoughts on those requirements, they are encouraged to submit those.
- Anonymous - Is the "scope" of this plan too reintroduce the EIR with only the 5 request of the courts?
- Answer – We are not required to reopen portions of the EIR the courts found valid and therefore we are not looking to reopen those portions of the EIR found valid. However the County is reviewing the permits from the last four years of permitting and if the commenter has something that they would like included in the scope they are encouraged to submit a comment.
- Lupe Martinez (Center for Race Poverty and the Environment) - Why are we rushing thru this process, can't wait until the pandemic is over, more people can participate?
- Answer – The importance of the oil and gas industry and the importance of these environmental protections to our communities. There is no end to when this pandemic “will be over”, it may be years or it may be more, and the Board of Supervisors has directed us to continue with this process. As far as allowing more people to participate, this is only the scoping meeting and comments can be provided in writing. There is no difference in the value of a written or verbal comment at this stage.
- Anonymous - Will each of the permits in the past 4 years be looked at by the 5 topics the courts introduced?
- Answer – We are not required to do that. The courts said they are valid and it was upheld by the appeals court. We are certainly looking at the information generated by those permits
- Anonymous - 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 al 10 people?
- Answer – This is a permitting question and can be answered by Staff offline since there is no permitting happening now.
- Anonymous - How can you be sure that the air funds generated by the plan are used in Kern County?
- Answer – We cannot be sure the funds will used in Kern County as they are not required to be use in Kern County. They can be used in the eight counties that make up the San Joaquin Valley. There is a differential for 25% of the funds to be used in Kern County if there are enough applications in Kern County. As a reminder, air is not local, it is a regional impact and so it has been set up regionally. The agreement is between the County and the San Joaquin Air District and we do monitor what grants they are giving out, where they are going, and what they are doing with that. They are primarily going to Kern , Tulare and Kings County, but some funds have gone to local agencies such as the City of Arvin who received funds to change out some of their

fleet to electric cars or natural gas cars and that is just one example of how the funds can be used.

- Anonymous - Can you give a specific date as to how long the old EIR will be available online?
- Answer – The EIR will not be taken down and will be available on the County Planning website for anyone who would like to view it.

No other public comments were presented.

Public testimony closed at approximately 1:53 p.m.

Summary prepared by
Cindi Hoover, Planner III

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

SCOPING MEETING

STARTS AT 1:30

INSTRUCTIONS AT KERNPLANNING.COM

May 13, 2020

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

SCOPING MEETING

Lorelei H. Oviatt, AICP

Director

Kern County Planning

And Natural Resources Department

May 13, 2020

Participation in this meeting

- The Q & A Button allows you to enter your name with questions.
- Verbal comments can not be accommodated
- Spanish translation is available

Closed Caption – press CC at the bottom right corner of the screen and use the Gear icon next to the CC icon to change the language setting.

Spanish Translation (verbal) can be accessed at

(224) 501-3412 Access Code: 408-162-717

Purpose of the Meeting

- To Present the Notice of Preparation for the Environmental Impact Report as required by the California Environmental Quality Act (CEQA Guidelines Section 15082 (1) (c) .

- To facilitate comments on the scope and content of the Draft Environmental Impact Report

- To answer questions about the comment opportunities and hearing process

Project Summary

- Revisions to Title 19-Kern County Zoning Ordinance (2020-A) Focused on Oil and Gas Local Permitting
- Environmental review directed by Fifth District Court of Appeal
- 2015 Ordinance and Kern County Oil and Gas Permitting Ended March 26, 2020.
- Current ordinance has no required permit, does have some development standards and required setback of 150 ft from residences and 300 feet from schools.
- Environmental review to address 5 subject areas directed by court and reconsider adoption of the Zoning Ordinace to start local permitting again for Oil and Gas permits with mitigation measures and detailed development standards.

Project Summary

- Project Location : San Joaquin Valley Floor – Kern County – Unincorporated areas.
- Supplemental Recirculated Environmental Impact Report
- Original EIR and Supplemental Grazing EIR will all be included in the recirculated document for reference.
- Court ordered focus on 5 areas for analysis
    1. Mitigation of water supply impacts
    2. Impacts from PM 2.5 emissions
    3. Mitigation for conversion of agricultural land
    4. Noise impacts
    5. Recirculation of the Multi-well Health Risk Assessment.

Process and Opportunities to Comment

- Notice of Preparation – 30 days - Ending May 29, 2020
- Draft Environmental Impact Report – 45 days
- Planning Commission – Public Hearing
- Board of Supervisors – Public Hearing
- Comments can be made throughout the entire process up until the Board of Supervisors votes at a public hearing.
- Request to be placed on notification list to Cindi Hoover, Lead Planner at hooverc@kerncounty.com

Comments and Questions

- Written comments can be submitted to the Staff Team Lead Planner at hooverc@kerncounty.com
- Submitted by US. Mail or delivery to Kern County Planning and Natural Resources Department 2700 M Street, Suite 100, Bakersfield, CA 93301
- Documents can be viewed online at https://kernplanning.com/
- NOP can be viewed at
- https://psbweb.co.kern.ca.us/planning/pdfs/notices/oil_gas_seir_nop.pdf

Further Information

- Kern County Planning and Natural Resources

https://kernplanning.com/

- Staff Team Lead Planner for Comments
- Cindi Hoover
  - Email – hooverc@kerncounty.com
  - Phone – (661) 862-8629

From: Isla, Nicholas@DOT
To: Cindi Hoover
Cc: Mendibles, Lorena@DOT
Subject: SCH #2013081079
Date: Friday, May 22, 2020 10:18:38 AM

Hi Cindi,

We've reviewed the above mentioned project and have no comments.

Thank you.

Nicholas Isla
Transportation Planner
California Department of Transportation
1352 West Olive Avenue
(559) 444-2583

STATE OF CALIFORNIA Gavin Newsom, Governor

NATIVE AMERICAN HERITAGE COMMISSION

NAHC HEADQUARTERS
1550 Harbor Boulevard
Suite 100
West Sacramento,
California 95691
(916) 373-3710
nahc@nahc.ca.gov
NAHC.ca.gov

April 29, 2020

Cindi L. Hoover
Kern County Planning and Natural Resources Department
2700 "M" Street Suite 100
Bakersfield, CA 93301-2323

Re: 2013081079, Revisions to Title 19 – Kern County Zoning Ordinance (2020 A) Focused on Oil and Gas Local Permitting Project, Kern County

Dear Ms. Hoover:

The Native American Heritage Commission (NAHC) has received the Notice of Preparation (NOP), Draft Environmental Impact Report (DEIR) or Early Consultation for the project referenced above. The California Environmental Quality Act (CEQA) (Pub. Resources Code §21000 et seq.), specifically Public Resources Code §21084.1, states that a project that may cause a substantial adverse change in the significance of a historical resource, is a project that may have a significant effect on the environment. (Pub. Resources Code § 21084.1; Cal. Code Regs., tit.14, §15064.5 (b) (CEQA Guidelines §15064.5 (b)). If there is substantial evidence, in light of the whole record before a lead agency, that a project may have a significant effect on the environment, an Environmental Impact Report (EIR) shall be prepared. (Pub. Resources Code §21080 (d); Cal. Code Regs., tit. 14, § 5064 subd.(a)(1) (CEQA Guidelines §15064 (a)(1)). In order to determine whether a project will cause a substantial adverse change in the significance of a historical resource, a lead agency will need to determine whether there are historical resources within the area of potential effect (APE).

CEQA was amended significantly in 2014. Assembly Bill 52 (Gatto, Chapter 532, Statutes of 2014) (AB 52) amended CEQA to create a separate category of cultural resources, "tribal cultural resources" (Pub. Resources Code §21074) and provides that a project with an effect that may cause a substantial adverse change in the significance of a tribal cultural resource is a project that may have a significant effect on the environment. (Pub. Resources Code §21084.2). Public agencies shall, when feasible, avoid damaging effects to any tribal cultural resource. (Pub. Resources Code §21084.3 (a)). **AB 52 applies to any project for which a notice of preparation, a notice of negative declaration, or a mitigated negative declaration is filed on or after July 1, 2015.** If your project involves the adoption of or amendment to a general plan or a specific plan, or the designation or proposed designation of open space, on or after March 1, 2005, it may also be subject to Senate Bill 18 (Burton, Chapter 905, Statutes of 2004) (SB 18). **Both SB 18 and AB 52 have tribal consultation requirements.** If your project is also subject to the federal National Environmental Policy Act (42 U.S.C. § 4321 et seq.) (NEPA), the tribal consultation requirements of Section 106 of the National Historic Preservation Act of 1966 (154 U.S.C. 300101, 36 C.F.R. §800 et seq.) may also apply.

The NAHC recommends consultation with California Native American tribes that are traditionally and culturally affiliated with the geographic area of your proposed project as early as possible in order to avoid inadvertent discoveries of Native American human remains and best protect tribal cultural resources. Below is a brief summary of portions of AB 52 and SB 18 as well as the NAHC's recommendations for conducting cultural resources assessments.

Consult your legal counsel about compliance with AB 52 and SB 18 as well as compliance with any other applicable laws.

AB 52

AB 52 has added to CEQA the additional requirements listed below, along with many other requirements:

1. Fourteen Day Period to Provide Notice of Completion of an Application/Decision to Undertake a Project: Within fourteen (14) days of determining that an application for a project is complete or of a decision by a public agency to undertake a project, a lead agency shall provide formal notification to a designated contact of, or tribal representative of, traditionally and culturally affiliated California Native American tribes that have requested notice, to be accomplished by at least one written notice that includes:

- **a.** A brief description of the project.
- **b.** The lead agency contact information.
- **c.** Notification that the California Native American tribe has 30 days to request consultation. (Pub. Resources Code §21080.3.1 (d)).
- **d.** A "California Native American tribe" is defined as a Native American tribe located in California that is on the contact list maintained by the NAHC for the purposes of Chapter 905 of Statutes of 2004 (SB 18). (Pub. Resources Code §21073).

2. Begin Consultation Within 30 Days of Receiving a Tribe's Request for Consultation and Before Releasing a Negative Declaration, Mitigated Negative Declaration, or Environmental Impact Report: A lead agency shall begin the consultation process within 30 days of receiving a request for consultation from a California Native American tribe that is traditionally and culturally affiliated with the geographic area of the proposed project. (Pub. Resources Code §21080.3.1, subds. (d) and (e)) and prior to the release of a negative declaration, mitigated negative declaration or Environmental Impact Report. (Pub. Resources Code §21080.3.1(b)).

- **a.** For purposes of AB 52, "consultation shall have the same meaning as provided in Gov. Code §65352.4 (SB 18). (Pub. Resources Code §21080.3.1 (b)).

3. Mandatory Topics of Consultation If Requested by a Tribe: The following topics of consultation, if a tribe requests to discuss them, are mandatory topics of consultation:

- **a.** Alternatives to the project.
- **b.** Recommended mitigation measures.
- **c.** Significant effects. (Pub. Resources Code §21080.3.2 (a)).

4. Discretionary Topics of Consultation: The following topics are discretionary topics of consultation:

- **a.** Type of environmental review necessary.
- **b.** Significance of the tribal cultural resources.
- **c.** Significance of the project's impacts on tribal cultural resources.
- **d.** If necessary, project alternatives or appropriate measures for preservation or mitigation that the tribe may recommend to the lead agency. (Pub. Resources Code §21080.3.2 (a)).

5. Confidentiality of Information Submitted by a Tribe During the Environmental Review Process: With some exceptions, any information, including but not limited to, the location, description, and use of tribal cultural resources submitted by a California Native American tribe during the environmental review process shall not be included in the environmental document or otherwise disclosed by the lead agency or any other public agency to the public, consistent with Government Code §6254 (r) and §6254.10. Any information submitted by a California Native American tribe during the consultation or environmental review process shall be published in a confidential appendix to the environmental document unless the tribe that provided the information consents, in writing, to the disclosure of some or all of the information to the public. (Pub. Resources Code §21082.3 (c)(1)).

6. Discussion of Impacts to Tribal Cultural Resources in the Environmental Document: If a project may have a significant impact on a tribal cultural resource, the lead agency's environmental document shall discuss both of the following:

- **a.** Whether the proposed project has a significant impact on an identified tribal cultural resource.
- **b.** Whether feasible alternatives or mitigation measures, including those measures that may be agreed to pursuant to Public Resources Code §21082.3, subdivision (a), avoid or substantially lessen the impact on the identified tribal cultural resource. (Pub. Resources Code §21082.3 (b)).

7. Conclusion of Consultation: Consultation with a tribe shall be considered concluded when either of the following occurs:

a. The parties agree to measures to mitigate or avoid a significant effect, if a significant effect exists, on a tribal cultural resource; or

b. A party, acting in good faith and after reasonable effort, concludes that mutual agreement cannot be reached. (Pub. Resources Code §21080.3.2 (b)).

8. Recommending Mitigation Measures Agreed Upon in Consultation in the Environmental Document: Any mitigation measures agreed upon in the consultation conducted pursuant to Public Resources Code §21080.3.2 shall be recommended for inclusion in the environmental document and in an adopted mitigation monitoring and reporting program, if determined to avoid or lessen the impact pursuant to Public Resources Code §21082.3, subdivision (b), paragraph 2, and shall be fully enforceable. (Pub. Resources Code §21082.3 (a)).

9. Required Consideration of Feasible Mitigation: If mitigation measures recommended by the staff of the lead agency as a result of the consultation process are not included in the environmental document or if there are no agreed upon mitigation measures at the conclusion of consultation, or if consultation does not occur, and if substantial evidence demonstrates that a project will cause a significant effect to a tribal cultural resource, the lead agency shall consider feasible mitigation pursuant to Public Resources Code §21084.3 (b). (Pub. Resources Code §21082.3 (e)).

10. Examples of Mitigation Measures That, If Feasible, May Be Considered to Avoid or Minimize Significant Adverse Impacts to Tribal Cultural Resources:

a. Avoidance and preservation of the resources in place, including, but not limited to:

i. Planning and construction to avoid the resources and protect the cultural and natural context.

ii. Planning greenspace, parks, or other open space, to incorporate the resources with culturally appropriate protection and management criteria.

b. Treating the resource with culturally appropriate dignity, taking into account the tribal cultural values and meaning of the resource, including, but not limited to, the following:

i. Protecting the cultural character and integrity of the resource.

ii. Protecting the traditional use of the resource.

iii. Protecting the confidentiality of the resource.

c. Permanent conservation easements or other interests in real property, with culturally appropriate management criteria for the purposes of preserving or utilizing the resources or places.

d. Protecting the resource. (Pub. Resource Code §21084.3 (b)).

e. Please note that a federally recognized California Native American tribe or a non-federally recognized California Native American tribe that is on the contact list maintained by the NAHC to protect a California prehistoric, archaeological, cultural, spiritual, or ceremonial place may acquire and hold conservation easements if the conservation easement is voluntarily conveyed. (Civ. Code §815.3 (c)).

f. Please note that it is the policy of the state that Native American remains and associated grave artifacts shall be repatriated. (Pub. Resources Code §5097.991).

11. Prerequisites for Certifying an Environmental Impact Report or Adopting a Mitigated Negative Declaration or Negative Declaration with a Significant Impact on an Identified Tribal Cultural Resource: An Environmental Impact Report may not be certified, nor may a mitigated negative declaration or a negative declaration be adopted unless one of the following occurs:

a. The consultation process between the tribes and the lead agency has occurred as provided in Public Resources Code §21080.3.1 and §21080.3.2 and concluded pursuant to Public Resources Code §21080.3.2.

b. The tribe that requested consultation failed to provide comments to the lead agency or otherwise failed to engage in the consultation process.

c. The lead agency provided notice of the project to the tribe in compliance with Public Resources Code §21080.3.1 (d) and the tribe failed to request consultation within 30 days. (Pub. Resources Code §21082.3 (d)).

The NAHC's PowerPoint presentation titled, "Tribal Consultation Under AB 52: Requirements and Best Practices" may be found online at: http://nahc.ca.gov/wp-content/uploads/2015/10/AB52TribalConsultation_CalEPAPDF.pdf

SB 18

SB 18 applies to local governments and requires local governments to contact, provide notice to, refer plans to, and consult with tribes prior to the adoption or amendment of a general plan or a specific plan, or the designation of open space. (Gov. Code §65352.3). Local governments should consult the Governor's Office of Planning and Research's "Tribal Consultation Guidelines," which can be found online at: https://www.opr.ca.gov/docs/09_14_05_Updated_Guidelines_922.pdf.

Some of SB 18's provisions include:

1. Tribal Consultation: If a local government considers a proposal to adopt or amend a general plan or a specific plan, or to designate open space it is required to contact the appropriate tribes identified by the NAHC by requesting a "Tribal Consultation List." If a tribe, once contacted, requests consultation the local government must consult with the tribe on the plan proposal. **A tribe has 90 days from the date of receipt of notification to request consultation unless a shorter timeframe has been agreed to by the tribe.** (Gov. Code §65352.3 (a)(2)).

2. No Statutory Time Limit on SB 18 Tribal Consultation. There is no statutory time limit on SB 18 tribal consultation.

3. Confidentiality: Consistent with the guidelines developed and adopted by the Office of Planning and Research pursuant to Gov. Code §65040.2, the city or county shall protect the confidentiality of the information concerning the specific identity, location, character, and use of places, features and objects described in Public Resources Code §5097.9 and §5097.993 that are within the city's or county's jurisdiction. (Gov. Code §65352.3 (b)).

4. Conclusion of SB 18 Tribal Consultation: Consultation should be concluded at the point in which:

  a. The parties to the consultation come to a mutual agreement concerning the appropriate measures for preservation or mitigation; or

  b. Either the local government or the tribe, acting in good faith and after reasonable effort, concludes that mutual agreement cannot be reached concerning the appropriate measures of preservation or mitigation. (Tribal Consultation Guidelines, Governor's Office of Planning and Research (2005) at p. 18).

Agencies should be aware that neither AB 52 nor SB 18 precludes agencies from initiating tribal consultation with tribes that are traditionally and culturally affiliated with their jurisdictions before the timeframes provided in AB 52 and SB 18. For that reason, we urge you to continue to request Native American Tribal Contact Lists and "Sacred Lands File" searches from the NAHC. The request forms can be found online at: http://nahc.ca.gov/resources/forms/.

NAHC Recommendations for Cultural Resources Assessments

To adequately assess the existence and significance of tribal cultural resources and plan for avoidance, preservation in place, or barring both, mitigation of project-related impacts to tribal cultural resources, the NAHC recommends the following actions:

1. Contact the appropriate regional California Historical Research Information System (CHRIS) Center (http://ohp.parks.ca.gov/?page_id=1068) for an archaeological records search. The records search will determine:

  a. If part or all of the APE has been previously surveyed for cultural resources.
  b. If any known cultural resources have already been recorded on or adjacent to the APE.
  c. If the probability is low, moderate, or high that cultural resources are located in the APE.
  d. If a survey is required to determine whether previously unrecorded cultural resources are present.

2. If an archaeological inventory survey is required, the final stage is the preparation of a professional report detailing the findings and recommendations of the records search and field survey.

  a. The final report containing site forms, site significance, and mitigation measures should be submitted immediately to the planning department. All information regarding site locations, Native American human remains, and associated funerary objects should be in a separate confidential addendum and not be made available for public disclosure.

b. The final written report should be submitted within 3 months after work has been completed to the appropriate regional CHRIS center.

3. Contact the NAHC for:

a. A Sacred Lands File search. Remember that tribes do not always record their sacred sites in the Sacred Lands File, nor are they required to do so. A Sacred Lands File search is not a substitute for consultation with tribes that are traditionally and culturally affiliated with the geographic area of the project's APE.

b. A Native American Tribal Consultation List of appropriate tribes for consultation concerning the project site and to assist in planning for avoidance, preservation in place, or, failing both, mitigation measures.

4. Remember that the lack of surface evidence of archaeological resources (including tribal cultural resources) does not preclude their subsurface existence.

a. Lead agencies should include in their mitigation and monitoring reporting program plan provisions for the identification and evaluation of inadvertently discovered archaeological resources per Cal. Code Regs., tit. 14, §15064.5(f) (CEQA Guidelines §15064.5(f)). In areas of identified archaeological sensitivity, a certified archaeologist and a culturally affiliated Native American with knowledge of cultural resources should monitor all ground-disturbing activities.

b. Lead agencies should include in their mitigation and monitoring reporting program plans provisions for the disposition of recovered cultural items that are not burial associated in consultation with culturally affiliated Native Americans.

c. Lead agencies should include in their mitigation and monitoring reporting program plans provisions for the treatment and disposition of inadvertently discovered Native American human remains. Health and Safety Code §7050.5, Public Resources Code §5097.98, and Cal. Code Regs., tit. 14, §15064.5, subdivisions (d) and (e) (CEQA Guidelines §15064.5, subds. (d) and (e)) address the processes to be followed in the event of an inadvertent discovery of any Native American human remains and associated grave goods in a location other than a dedicated cemetery.

If you have any questions or need additional information, please contact me at my email address: Nancy.Gonzalez-Lopez@nahc.ca.gov.

Sincerely,

Nancy Gonzalez

Nancy Gonzalez-Lopez
Staff Services Analyst

cc: State Clearinghouse

Office of the Fire Marshal
Kern County Fire Department

Fire Prevention
2820 M St. • Bakersfield, CA 93301 • www.kerncountyfire.org
Telephone 661-391-3310 • FAX 661-636-0466/67 • TTY Relay 800-735-2929

May 28, 2020

Kern County Planning and Natural Resources Department
2800 M St., Bakersfield, CA 93301
Attn.: Cindi Hoover

Re: Kern County Fire Department Comments Regarding Planning Department Project Notice of Draft Supplemental Recirculated EIR (SCH #2013081079)

To Whom It May Concern,

The Kern County Fire Department, as the local fire authority, has received a request for comments regarding **Notice of Draft Supplemental Recirculated EIR (SCH #2013081079)** . Upon initial review it has been determined that there are no Fire Code concerns regarding this project. We look forward to reviewing the final EIR upon submission.

Please feel free to call our Fire Prevention Office at 661-391-3310 with any questions.

Sincerely,
Michael Nicholas
Assistant Fire Marshal
Kern County Fire Department

Association of Irritated Residents
29389 Fresno Ave
Shafter, CA 93263

May 29, 2020

Kern County Planning and Natural Resources Department
Cindi Hoover, Lead Planner hooverc@kerncounty.com
2700 M Street, Suite 100
Bakersfield, CA 93301

RE: SREIR (SCH #2013081079) Oil and Gas Local Permitting

To Whom it May Concern:

It seems that Kern County has very narrowly interpreted the Appellate Court ruling and is trying to limit the scope of further analysis and better mitigation to just a few limited items within the five areas. We disagree with these limits and have broader comments on each area the court found inadequate.

1. Mitigation of Water Supply Impacts

A. If produced water is of sufficient quality to be used for irrigation by agriculture then SGMA must apply to that water. If the water is being used by agriculture without removal of the salts then it is assumed to meet the quality definition where SGMA should apply. Groundwater levels must be measured throughout any oilfield where produced water is used for irrigating cropland or for water banking as done in CAWELO, North Kern Water Storage District, and the Rosedale-Rio Bravo Water Storage District . The average depth to groundwater in these oil fields, especially on the East side of Kern County such as in the Kern River, Kern Front, and Poso Creek oil fields, cannot be allowed to increase over time under SGMA. This higher quality produced water may one day be more valuable than the oil mixed into it. Agricultural entities may one day wish to pump this water for irrigation purposes and dispose of the oil in the most economical way possible. In other words, if the quality of the produced water is good enough for growing crops then SGMA must apply to the oil field producing the water.

B. Any oil company with active oil production within the boundaries of agricultural which use groundwater for irrigation must immediately plug and properly abandon all inactive wells. Inactive wells should be defined as any well sitting unused for a period of ten or more years. The current operator of an oil field must be immediately responsible to properly plug and abandon all idle wells in the oil field where they operate.

C. Any buried or abandoned drilling mud sumps which exist on farmland must be cleaned up. This means buried material must be removed and clean soil similar to surrounding top soil must fill the area. This must be done retroactively and immediately by the current operator in all active oil fields.

D. Open produced water percolation ponds, such as McKittrick 1, 1-3, and 3 operated by Valley Water Management and located within a mile of the intersection of Lokern Road and Hwy 33, and elsewhere where the produced water is in no way suitable as irrigation water because of salt levels or toxic metals, must cease all percolation activity immediately and be closed if there is any evidence of the produced water moving horizontally in a direction towards currently irrigated farmland.

E. Any surface expression or oil leak coming out of the ground in an oil field within 500 feet of a steam, dry stream bed, arroyo, gully, wash, etc., where water runs occasionally, must be stopped immediately by any means necessary including complete cessation of steam injection or steam flooding within 5,000 feet of the leak. Every barrel of fluid coming to the surface in the area defined above and within the boundaries of an active oil field should result in a minimum fine of $1,000 per barrel which will be used to protect endangered species and enhance their habitat in Kern County.

F. No produced water of any quality should ever be allowed to run down a natural, unlined, drainage channel. Neither should it be allowed to be transported via an unlined dirt canal. All produced water must be conveyed from the wellhead by impervious cement or metal pipeline to where it is cleaned, recycled, used as irrigation water or otherwise disposed.

G. Volatile Organic Compound emissions, including methane, from produced water which is exposed to the air, must be calculated and measured continuously and mitigated for their impact on air quality and/or as a greenhouse gas.

2. Impacts from PM2.5 emissions

A. The county must look at PM10 emissions as well as PM2.5. All oil field roads carrying oil production related vehicles and machinery must be treated to reduce dust emissions. Some of that dust is PM2.5 which is one reason PM10 must be mitigated as well as PM2.5. We know that disease such as Valley Fever can be carried on dust particles plus these particles are harmful to human health by themselves even without fungus, virus, and bacteria particles attached to them.

B. There are two kinds of PM2.5, direct and secondary. All direct emissions must be mitigated and all precursors of secondary PM2.5 formation must be mitigated. Direct emissions come from all types of combustion, including all vehicles and machinery burning fossil fuel and all boilers burning oil or natural gas. Dust also creates PM2.5. Any type of NOx, SOx, or ammonia emissions must be considered precursors to PM2.5 and mitigated. Since there are a limited number of days when there are violations of the daily PM2.5 Federal Health Standard but severe negative health consequences because of those violations, every oil field operator must make a plan to cut back PM2.5 direct or precursor emissions by 20% for those days when the air district predicts a violation will occur. This would be on any day when the air district predicts the AQI to be Orange or worse. Other required mitigations help reduce overall pollution levels on an annual basis but direct reductions on the worst days is more effective at protecting public health. These reduction plans must be enforced through required reporting of implementation details and inspections. Punitive fines for non-compliance must be in place with the money going for local health care improvements.

C. All current oil pumps outfitted with combustion engines must be converted to electric motors within six months if the electric grid is available within 1500 feet or less. No new oil wells may be installed with internal combustion engines under these conditions.

D. Kern County must ensure that all mitigation for PM2.5 emissions is done in Kern County. We have the highest levels of PM2.5 in the nation. If money is paid to offset PM2.5 pollution in the oil fields, it must be spent in Kern County. If these mitigation funds are paid to the air district for their incentive programs, all the money must be spent in Kern County with no decrease in any other funding that would be spent in Kern by the air district. It is not fair to shift money for air pollution reductions in Kern County to the far less polluted northern end of the San Joaquin Valley under current air district guidelines where money is spent more or less equally throughout the district's eight counties.

E. Emission Reduction Credits authorized by the San Joaquin Valley Air Pollution Control District should not be used to mitigate new sources of PM2.5 in the oil fields. These credits can be over 20 years old so they are meaningless and should not be used. All mitigation for air pollution must take place with real reductions within the county and at the time of the current emissions which are being mitigated.

F. Electrical generation is predominantly by combustion of natural gas in Kern County oil fields. Every oil field should have a photovoltaic installation providing at least 75% of the common, everyday electrical needs of the oil production equipment such as the pumps. This will do three things. 1) it will lesson the need for local electrical generation involving combustion thus improving Kern air quality. 2) It will be cheaper, over time, for oil field costs involving electricity purchased from the grid meaning it will be good for the economy. 3) It will reduce the carbon intensity of oil from Kern County helping to ensure that oil produced in Kern County will be used in California as opposed to the importation of oil from places like Saudi Arabia which have lower carbon intensity values and thus is more apt to help California meet its greenhouse gas reduction goals. There should be a plan to install solar panels over a reasonable 5 year time frame for every oil field operation in Kern County until the 75% target is met or exceeded. New oil wells should require new solar panels for 100% of their projected lifetime electrical needs.

G. Flaring of gas in oil fields causes PM2.5, NOx, and VOC emissions. Flaring can occur continuously for many hours and even days. Very large volumes of gas can be flared with the excuse that it is uneconomical to collect, clean, and sell the gas. Two things should be required. Flaring should be reduced to a minimum beyond what is required by the air district and flares should consist of mechanical draft enclosed combusters with pollution control equipment. Open flaring should be banned in Kern County. Any new flares should be required to be enclosed and current open flares must minimize their flaring at least 10% from the previous 5 year average for each year they continue to operate or be converted to mechanical draft enclosed combusters. There should also be a mitigation fine based on the quantity of natural gas which is flared. The fine should be at least equal to the retail value of that gas by volume.

3. Mitigation of conversion of agricultural land

A. If drilling is to be permitted on farmland then the farmer or landowner, who may or may not have the mineral rights, can veto the location selected by the oil company for a drilling site. Instead, the farmer may select a corner or edge of their field where irrigation and farming operations will be least interrupted in the judgement of the farmer and within 1500 feet of the oil field operator's desired location.

B. Absolutely no drilling mud pits may be used on farmland.

C. All buried and covered drilling mud pits on farmland which has 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. If an operator failed to do this in the past and the same operator wishes to drill a new well, or enhance production at a currently active well, then old drilling mud pits or partial pits on land available for farming and used previously by the same operator must be first cleaned and remedied to a condition suitable for agriculture. Only then can new activity in the oil field proceed.

D. All soil around oil wells located on farmland must be kept clean. This means any soil around oil wells which is contaminated with oil or other substances used in oil production or for the purpose of enhancing oil production must be removed at least quarterly and replaced with clean soil.

E. To avoid contamination of the soil around oil wells located on farmland, all wells and pumps must be raised above the level of the surrounding land with concrete pads at least 18 inches high. There should never be a situation where flooding from storms or irrigation causes water to pool within 20 feet of an existing active oil well even if the pump jack or pumping equipment has been removed.

F. No more than one drilling site per 40 acres of farmland. Multiple wells may be drilled at one site but the total area cannot be more than one acre out of 40 acres.

G. Every acre or partial acre used for oil production must be leased from the farmer or landowner with payment equivalent to the expected gross per acre from the adjacent land and crop. In no case should this payment be less than $2500 per year per acre or partial acre.

H. Farmworkers must be protected from all dangerous oil production activities. Certain activities such as fracking or acid injecting, where a buffer zone for other nearby workers is necessary, need to be arranged at least two weeks in advance with the farmer so that regular farming activities can be planned around that time.

I. Where high pressures (greater than 250 psi) in pipes above ground are used during oil production activities on farmland, there must be clear warning signs about possible dangers for nearby farmworkers and the general public. This should be done where produced water is being injected for disposal or to pressurize the oil field and where natural gas is being injected for storage or disposal. Signs should state the danger, the probable high pressure, and the type of operation taking place with what substances are in the pipes. Signs should be in Spanish and English.

J. Underground pipelines used to carry gas or various fluids from wells to processing sites and vice-versa must be checked for leaks every month. Some leaks are very small and are not immediately detected by pressure drops. Sensitive instruments need to check all pipelines for leaks on farmland at every point of their route.

4. Noise impacts

A. Flaring of gas is the noisiest regular occurrence in oil fields. Flaring can occur continuously for many hours and even days. The noise of a large flare can sound like a jet engine and cause typical noise related problems to nearby residents, students and non-oilfield workers. The noise from a large flare can be noticeable and irritating up to one mile away. Two things should be required. Flaring should be reduced to a minimum beyond what is required by the air district and flares should be mechanical draft enclosed combustion equipment with the best available pollution control equipment (also mentioned in Part 2G above regarding reduction of oil field related PM2.5). Open flaring should be banned in Kern County and phased out over the next ten years.

B. Drilling of oil wells and operations like fracking produce lots of noise any time of the day but for durations of a few weeks to less than one day. Noise barriers should be erected between these activities and any residential, school, or business area within a quarter mile. Temporary insulated walls which are 20 feet in height should reduce this noise significantly.

C. Oil field traffic involving heavy duty trucks should be routed around schools and residential areas and not take roads adjacent to these areas wherever possible. For schools this is important during school hours. For residential areas this needs to be done all day and night.

5. Recirculation of the Multi-Well Health Risk Assessment

The oil industry in Kern County is the number one source of local air pollution. Total oil industry NOx emissions, directly emitted PM2.5, and VOC emissions dominate the stationary source category. The trucks and moving of machinery plus worker traffic are significant sources of total mobile source emissions of NOx, VOC and PM2.5 emissions. The mobile source contribution from oil field production needs to be accurately estimated and mitigated. The health impacts of this air pollution are well known.

The total economic related health costs of not meeting national air quality standards in Kern County is well over $1 billion per year. What proportion of that cost comes from oil field production and all of the indirect but related activities? This must be considered for the current situation and predicted for any new activity.

Mitigation calculations must include all health impacts on the local population. For these reasons alone the Multi-Well Health Risk Assessment must be recirculated for public review and comment.

Sincerely,

Association of Irritated Residents
Tom Frantz, President

Cindi Hoover

From:	Chelsea Tu <ctu@crpe-ej.org>
Sent:	Monday, May 11, 2020 5:00 PM
To:	Cindi Hoover
Cc:	Lorelei Oviatt; Craig Murphy
Subject:	Re: Scoping Meeting May 13, 2020

Hi Cindi:

Thank you for your email, and for letting me know more about your thinking.

In general, the County should open this scoping meeting for oral comments by the public to ensure that it allows for the meaningful public participation and informed decision-making that CEQA mandates.

Low-income residents and communities of color experience disproportionate environmental and health impacts from oil and gas activities in Kern County. However, the County's current meeting set up not only restricts the general public's ability to provide oral comments, it also places low-income and Spanish speaking/non-English speaking residents at a significant disadvantage from being able to meaningfully participate in the meeting.

We therefore request that all members of the public be allowed to provide oral comments by phone and through the Teams App. Opening a phone line for questions and comments during the meeting is necessary to allow residents who do not have the financial means to access a computer and/or Internet to meaningfully participate.

We appreciate that the County will provide a phone line for the public to listen to the meeting in Spanish, as many residents in Kern County are monolingual or primarily Spanish speakers.

Since the County will provide the live interpretation line, we request that those who call into the line be able to provide oral comments or ask questions in Spanish, and have their questions or comments be interpreted and shared in English during the scoping meeting. We do not believe the County would need to make any technological changes in order to meet this request. We also strongly encourage that the County provide two-way Spanish and English live interpretation throughout the entirety of this meeting, and for future meetings on this matter.

Relatedly, we appreciate that the public can call the County to share oral comments outside of the scoping meeting. **We would like to confirm that the public can also call you to submit oral comments before and after the meeting, through at least May 29 at 5pm. We also want to ensure that the comments that you receive in Spanish will be translated into English and considered by the County.**

Finally, we request that the County translate the notice of preparation and all future materials related to the Oil and Gas Ordinance and the supplemental EIR into Spanish, and publicly share the relevant materials in both English and Spanish, prior to any relevant meetings.

Please feel free to give me a call at 510-717-9092, or let me know if there is a time today or tomorrow you could chat.

Thank you, Chelsea

Chelsea Tu
Senior Attorney
Center on Race, Poverty & the Environment
Office: 415-346-4179 x 304
Cell: 510-717-9092
5901 Christie Avenue Suite 208
Emeryville, CA 94608

Cindi Hoover

From: Colin O'Brien <cobrien@earthjustice.org>
Sent: Friday, May 15, 2020 4:05 PM
To: Lorelei Oviatt <Loreleio@kerncounty.com>; Department, Planning <Planning@kerncounty.com>
Cc: Chelsea Tu <ctu@crpe-ej.org>; elly.benson@sierraclub.org <elly.benson@sierraclub.org>; hkretzmann@biologicaldiversity.org <hkretzmann@biologicaldiversity.org>; bchan@earthjustice.org <bchan@earthjustice.org>; rweber@earthjustice.org <rweber@earthjustice.org>
Subject: NOP of a Draft Supplemental Recirculated Environmental Impact Report (SCH # 2013081079)

Dear Ms. Oviatt –

I hope that you and yours are healthy and staying safe during this challenging time.

In light of the significant obstacles that we and many others are facing in the midst of the current COVID-19 health crisis, please find attached a letter requesting an extension of the comment period for the County's Notice of Preparation of a Draft Supplemental Recirculated Environmental Impact Report (SCH # 2013081079).

Your consideration of this request is much appreciated.

Sincere thanks,
Colin

____

Colin C. O'Brien
Pronouns: he/him/his
Staff Attorney

Earthjustice
50 California Street, Suite 500
San Francisco, CA 94111
T: 415. 217.2010
F: 415.217.2040
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May 15, 2020

Via electronic mail

Lorelei Oviatt, AICP, Director
Kern County Planning and Natural Resource Dept.
2700 "M" Street, Suite 100
Bakersfield, CA 93301-2323
Loreleio@kerncounty.com
planning@kerncounty.com

Re: Request for Public Comment Extension for Notice of Preparation of a Draft Supplemental Recirculated Environmental Impact Report to the Revisions to Title 19-Kern County Zoning Ordinance (2020-A) Focused on Oil and Gas Local Permitting (SCH # 2013081079)

Dear Ms. Oviatt:

We are writing with regards to the public comment period for the Notice of Preparation of a Draft Supplemental Recirculated Environmental Impact Report (the "NOP") to the reconsideration of the Kern County Zoning Ordinance for local permitting for oil and gas (the "Ordinance"). On behalf of the undersigned organizations, we ask the Kern County Planning and Natural Resource Department to extend the deadline for scoping comments from the general public. We believe a 45-day extension is appropriate given the extraordinary circumstances due to the COVID-19 global pandemic. We ask that the due date for scoping comments from the public be pushed back to July 13, 2020. The current deadline of May 29, applicable to government agencies, should not be applied to limit general public input because it does not give adequate time for the public to analyze and respond to the NOP.

Due to the global pandemic, our offices—like those of many public advocacy groups—have been forced to close, and our staff has had to reduce its capacity due to childcare, illness, and other circumstances beyond our control. Government agencies have also scaled back operations. State and federal courts, regulating agencies, and local and regional governmental bodies have implemented postponements due to the most extreme pandemic of our lifetime. The Planning Department itself has postponed or canceled a number or meetings and hearings in response to the restrictions on daily activities.

Therefore, it is concerning that the County issued its NOP on April 29, in the midst of a statewide shelter-in-place order and during a nationwide increase of COVID-19 cases that continues to cause serious disruption to everyday life. Furthermore, the short 30-day period puts a substantial demand on the limited time and resources of our organizations and the communities affected by this Ordinance. The County has claimed that the environmental impact report for this Ordinance will serve as the lone environmental review authorizing tens of thousands of new oil and gas wells over decades. The 30-day period is thus also inadequate given the breadth of environmental and public health impacts the Ordinance will bring.

Our State's bedrock environmental protection and community right-to-know law, the California Environmental Quality Act, was intended to allow the public and public officials to be fully informed about projects and be able to participate in decision-making in a meaningful way. The rush to move forward with a new EIR and proceed with minimal time for public input falls short of these principles. Extending the comment deadline for 45 days would allow the public and organizations like ours to have sufficient time to obtain the relevant documents, consult with experts, and provide informed comments to the County on this important matter.

We welcome the opportunity to work with you moving forward.

Best regards,

Chelsea Tu/Caroline Farrell
Center on Race, Poverty & the Environment

Colin C. O'Brien

Colin O'Brien/Byron Chan
Earthjustice

Elly Benson

Elly Benson
Sierra Club

Hollin Kretzmann

Hollin Kretzmann
Center for Biological Diversity

From:	Colin O"Brien
To:	Cindi Hoover
Cc:	hkretzmann@biologicaldiversity.org; Chelsea Tu; elly.benson@sierraclub.org; bchan@earthjustice.org; rweber@earthjustice.org
Subject:	Notice of Preparation of a Draft Supplemental Recirculated Environmental Impact Report (SCH # 2013081079)
Date:	Friday, May 29, 2020 4:32:07 PM
Attachments:	Scoping Comments for SREIR NOP__2020-05-29.pdf Attachment A - oil_gas_sreir_scoping_mtg_instructions_May 2020.pdf Attachment B - Emails on Translation for Scoping Process_May 2020.pdf

Dear Ms. Hoover:

Please find attached scoping comments on the County's Notice of Preparation of the Draft Supplemental Recirculated Environmental Impact Report for the project entitled "Revisions to Title 19- Kern County Zoning Ordinance (2020-A) Focused on Oil and Gas Local Permitting (SCH # 2013081079)."

In addition to our comments, I am also providing two accompanying attachments. If you have difficulty opening any of the three attached files, do let me know.

These comments are submitted on behalf of 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, Earthjustice, and Sierra Club.

If you could acknowledge receipt of this email, that would be much appreciated.

Sincere thanks,
Colin

____

Colin C. O'Brien
Pronouns: he/him/his
Staff Attorney
Earthjustice
50 California Street, Suite 500
San Francisco, CA 94111
T: 415. 217.2010
F: 415.217.2040
earthjustice.org

EARTHJUSTICE

May 29, 2020

Via electronic mail

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: **Notice of Preparation of a Draft Supplemental Recirculated Environmental Impact Report (SCH # 2013081079)**

Dear Ms. Hoover:

We are writing to provide comments on the County's Notice of Preparation of the Draft Supplemental Recirculated Environmental Impact Report for the project entitled "Revisions to Title 19- Kern County Zoning Ordinance (2020-A) Focused on Oil and Gas Local Permitting (SCH # 2013081079)" (the Project).

Since its inception, we have informed the County that the Project—rather than providing an effective means for the County to adequately identify, analyze, and mitigate the significant environmental impacts caused by oil and gas development—impermissibly attempts to insulate all such activity from meaningful site-specific review and local input and accountability, in violation of CEQA's core principles. Further, given the unprecedented immensity of the so-called "Project," it is hard to conceive of an analysis that could provide the requisite detail and local specificity that CEQA requires to inform the public and decision makers and to mitigate significant impacts. Indeed, both the Kern County Superior Court and the Court of Appeal found substantial flaws with the original Environmental Impact Report (EIR) for this Project, and the latter has specified that the County must revisit and revise its analysis in substantial ways. *See King and Gardiner Farms, LLC v. County of Kern* (2020) 45 Cal.App.5th 814 ("*King*").

We do not believe the County should proceed with the Project. To the extent the County insists on moving forward, we offer these comments to assist the County with its scoping process. We reserve the right to identify new issues, provide additional information, and propose additional mitigation measures during the administrative process for the Supplemental Recirculated Environmental Impact Report (SREIR) and the Project.

I. The County must make its CEQA process accessible to the County's many Spanish-language speakers.

CEQA prioritizes meaningful public involvement and, in this instance, the County must disclose environmental information and allow for public participation in Spanish in order to meet CEQA's public participation requirements. CEQA Guidelines §§ 15002(a)(1) & (4), 15201. The majority of residents in Kern County are Latino, and Latinos are disproportionately impacted by oil and gas activity in the County. The Court of Appeal's recent decision underscores the desirability of translation and interpretation services as well as the County's authority to provide them; further, it advises that the County must be able to substantiate any decision to ignore legitimate community needs. Slip Opinion at 125-26. To allow Spanish-speaking residents to participate meaningfully in the CEQA review for this Project, the County can and must translate all notices and key documents—or important portions thereof—into Spanish; provide simultaneous English and Spanish interpretation during all public meetings and hearings; and accept and consider verbal and written comments in both English and Spanish.

Kern County should provide Spanish translation because a significant portion of the County's population speaks Spanish. Over 486,000 Latinos live in Kern County, making up the majority (approximately 54 percent) of Kern County's population.[1] Among county residents, more than 39 percent speak Spanish, and at least 16 percent of the county's Spanish speakers cannot speak English, or do not speak English well or very well.[2] Delano, Arvin, Lamont, Lost Hills, and Shafter—all communities heavily impacted by oil and gas drilling—are also all located in census tracts that have linguistic isolation scores above 90 under CalEnviroScreen, meaning there are many households in these communities where no one over age 14 speaks English well. Linguistic isolation is a particular concern in Lost Hills, which scores in the 99th percentile for linguistic isolation.[3]

Making the CEQA process accessible to Spanish-speaking community members is particularly important because Latino residents are disproportionately impacted by oil and gas activity within Kern County. Although Latinos make up 54 percent of the County's population, they make up of over 64 percent of residents living within 1 mile of oil and gas wells in the county,[4] and many Latino community members live, go to school, or work immediately adjacent to oil and gas wells. Among the undersigned community groups, Committee for a Better Shafter, Committee for a Better Arvin, Comité Progreso de Lamont, and Comité de Lost Hills en Acción are made up of residents who live in communities that are surrounded by oil and gas wells. Given that this Project aims to authorize more than two decades of oil and gas development, including 67,000 or more new producing wells, the County must take steps to insure that the residents whose quality of life is most affected will receive notice, have access to understandable information, and be able to offer comments.

Unfortunately, to date, the County has largely refused to make its CEQA process for the Project accessible to Spanish-speaking community members who want to participate. Among the signatories to this letter are Kern County-based groups that consist of—or work directly with—

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[1] United States Census Bureau, Quick Facts Kern County, CA, *available at* https://www.census.gov/quickfacts/kerncountycalifornia.

[2] United States Census Bureau, Selected Social Characteristics in the United States, *available at* https://data.census.gov/cedsci/table?d=ACS%205-Year%20Estimates%20Data%20Profiles&table=DP02&tid=ACSDP5Y2018.DP02&y=2018&g=0400000US06_0500000US06029.

[3] CalEnviroScreen 3.0, a*vailable at:* https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30.

[4] Natural Resources Defense Council, Drilling in California: Who's At Risk?, at 13, *available at:* https://www.nrdc.org/media/2014/141022.

residents who are monolingual Spanish speakers or Spanish-speakers who do not speak English as their primary language. Our groups repeatedly requested that the County provide translated documents and simultaneous interpretation during the County's previous CEQA process for the Project, but to no avail.

With a new CEQA process underway for the Project, the County can and must make the proceedings accessible to Spanish-speaking residents. To this end, we were encouraged that the County acknowledged the need for Spanish translation and provided simultaneous English to Spanish interpretation during its scoping meeting on May 13, 2020.

At the same time, it is unclear how Spanish-speaking residents would have known about the scoping meeting since the County failed to translate the Notice of Preparation into Spanish, despite a direct request for translation made by the Center on Race, Poverty, & the Environment on May 11, 2020. Moreover, the May 13 scoping meeting did not provide a full opportunity for public participation because the County refused to allow comments or questions by Spanish-speaking community members through the Spanish interpretation line.

Also concerning, the County has made contradictory statements about whether it will accept verbal comments for the record during the scoping period—a critical vehicle for participation by Spanish-speaking community members, particularly during the current COVID-19 pandemic. Official instructions issued by the County state: "Q: How can I provide verbal comments for the record? A: While we recommend you provide written comments via the email or the mailing address below, verbal comments may be submitted by phone to Cindi Hoover, Lead Planner, at (661) 862-8629."[5] The County has since backtracked, denying that verbal comments submitted through calls or voicemails will be incorporated into the record. Equally troubling, the County has stated that it will not translate into English, and therefore will not consider, any voicemail comments made in Spanish during the scoping process.[6]

The County possesses the resources, technology, and know-how to serve its Spanish-speaking residents. Going forward, the County can and must take the steps listed below to allow Spanish-speaking residents to participate meaningfully in the CEQA process for this Project. Specifically, the County must:

- translate the notice of preparation and all future notices related to the Project into Spanish, including any notice of availability, notices of public meetings or hearings, and notices of determination (if applicable);
- translate the SREIR—or, at a minimum, key portions of the SREIR including the executive summary, project description, and sections on air quality, water quality, cumulative impacts, and alternatives sections—into Spanish;

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[5] *See* Attachment A: Teams Live Event Scoping Meeting Instructions, at page 3, *available at:* https://psbweb.co.kern.ca.us/planning/pdfs/oil_gas/oil_gas_sreir_scoping_mtg_instructions.pdf.
[6] *See* Attachment B: Email Correspondence re Translation for Scoping Meeting.

- translate at least the executive summary of the updated health risk assessment into Spanish;

- make translated materials available at the same time as English versions;

- provide two-way simultaneous interpretation for future public meetings and hearings;

- consider written and oral comments made in English as well as in Spanish, and include them in the record; and

- translate any findings and statements of overriding consideration (if applicable).

II. The County must address it failure to address PM2.5 and the larger failures of Mitigation Measure 4.3-8 to mitigate air quality impacts as described in the original EIR.

The Court of Appeal rejected the County's prior analysis of air quality impacts because "the EIR failed to discuss the impact of [Mitigation Measure 4.3-8] on PM2.5 emissions or, alternatively, provide an explanation for why there is no separate discussion of the measure's impact on PM2.5 emissions." *King*, 45 Cal.App.5th at 895. Further, the Court of Appeal faulted the County because Mitigation Measure 4.3-8 "does not provide for enforceable mitigation of PM2.5 emissions and the Board made no finding that mitigation of PM2.5 was not feasible." *Id*. The Court specified that the County, in addressing these errors, must "update its analysis of air quality and PM2.5 levels." Slip Opinion at 148.

Consistent with the Court's directive that the County must analyze air quality, $PM_{2.5}$ levels, and the prior EIR's exclusion of $PM_{2.5}$ from Mitigation Measure 4.3-8, the SREIR must account for the factors described below.

As an initial matter, the County's revised analysis must address the fact that the San Joaquin Valley is not—as predicted in the EIR—achieving any federal or state ambient air quality standards for $PM_{2.5}$.[7] To the contrary, the Valley's air quality remains the worst in the country for $PM_{2.5}$.[8] It is also among the worst in the country for ozone.[9]

Second, the County must address the effectiveness of Mitigation Measure 4.3-8 and the accompanying Oil and Gas Emission Reduction Agreement (OGERA) that the County signed with the San Joaquin Valley Air Pollution Control District (the District)—which is failing to mitigate air emissions as described in the EIR. Whereas the EIR promised "full mitigation of air quality impacts," with emissions ultimately "mitigated to net zero" (AR008676)[10] and annual

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[7] San Joaquin Valley Air Pollution Control District (SJVAPCD), Ambient Air Quality Standards & Valley Attainment Status, *available at* https://www.valleyair.org/aqinfo/attainment.htm.

[8] American Lung Association, State of the Air 2020 at 20-21, 23-24, *available at* http://www.stateoftheair.org/assets/SOTA-2020.pdf.

[9] *Id*. at 22, 25.

[10] "AR" citations refer to the Administrative Record compiled for the original EIR.

"emission reductions from implementing the OG-ERA . . . expected to match the emissions from drilling new wells" (AR008681-81)—this has not been the case.

Pursuant to the OGERA, the County has paid to the District, through November 2019, almost $89 million in fee monies to fund pollution-reducing projects intended to offset otherwise unregulated oil and gas emissions.[11] The District, however, has failed to spend these funds. For example, the District's most recent annual report indicates that it received almost $43 million from the OGERA and other emission reduction agreements for the period from July 1, 2018 to June 30, 2019, but was only able to spend $12.5 million and encumber another $6.6 million.[12] This shortfall in spending and encumberances left the District with an ending unencumbered balance of more than $48 million—reflecting an ever-growing failure of the District to spend OGERA and other emission reduction agreement receipts. The period-ending unencumbered balance was $13.6 million for 2018[13] and $6.4 million for 2017.[14]

These failures to spend OGERA funds mean air pollution from new oil and gas drilling is increasing unabated and worsening air quality. Remarkably, the County issued almost 1,200 new oil and gas permits in the first year after the Ordinance with no mitigation whatsoever from Measure 4.3-8.[15] Alarmingly, a significant and growing gap between permit issuances and pollution-reducing projects continues. For example, a 2018 report by the District indicates that in the 12-month period from July 1, 2017 to June 30, 2018, the District only reduced 853 tons of NOx and 181 tons of PM10 using emission reduction agreement funds.[16] But these quantities represent the total reductions accomplished by the District pursuant to emission reduction agreements for 36 separate development projects, of which the Ordinance is just one.[17] Critically, even if all of these reductions were dedicated to offsetting emissions from the Project, they would be insufficient: 853 tons of NOx is only enough to mitigate emissions from 367 new wells, which is a small fraction of the number of wells that the County has permitted each year so far, and an even smaller fraction of the 3,647 wells that the Ordinance allows annually.[18] The District's most recent annual report likewise indicates that it has only been able to abate enough air pollution to offset emissions from several hundred new wells during the 12-month reporting period—which is well short of the 1,000+ new well permits the County has issued annually.[19]

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[11] Kern County Oil and Gas Permitting Program Annual Progress Report (December 1, 2018 to November 30, 2019) at 7, 9-10.
[12] SJVAPCD 2019 Annual Report - Indirect Source Review Program at 9, *available at* https://www.valleyair.org/ISR/Documents/2019-Annual-Report.pdf.
[13] SJVAPCD 2018 Annual Report - Indirect Source Review Program at 10, *available at* https://www.valleyair.org/ISR/Documents/2018-Annual-Report.pdf.
[14] SJVAPCD 2017 Annual Report - Indirect Source Review Program at 7, *available at* https://www.valleyair.org/ISR/Documents/2017-ISR-Annual-Report.pdf.
[15] Kern County Oil and Gas Permitting Program Annual Progress Report (December 9, 2015 to November 30, 2016) at 4-5.
[16] SJVAPCD 2018 Annual Report at 11.
[17] *Id*. at 8.
[18] *See* AR029118 [noting in Table 4.3-30 that, for 2018, each new well will emit 2.32 tons of NOx]; Kern County Oil and Gas Permitting Program Annual Progress Report (December 1, 2016 to November 30, 2017) at 4 [permits issued through Nov. 2017]; AR000989 [annual well limit].
[19] *See* SJVAPCD 2019 Annual Report at 10; Kern County Oil and Gas Permitting Program Annual Progress Report (December 1, 2018 to November 30, 2019) at 6.

Third, as part of its assessment of the effectiveness of Mitigation Measure 4.3-8, the County must assess whether adequate pollution-reducing projects even exist within the San Joaquin Valley for the measure to succeed. The significant, ongoing disparity between new emissions authorized and inadequate emissions reductions to compensate underscores the need for such analysis. The data needed to conduct this analysis is readily available. In fact, the EIR estimated the Project's emissions as a percentage of County-wide and Valley-wide emissions (AR001030), indicating that the County has access to relevant emissions inventories.

Fourth, the County should insist that fee monies collected pursuant to Mitigation Measure 4.3-8 be spent on pollution-reducing projects in Kern County, instead of allowing the District to spend the money elsewhere. The OGERA states that the County will actively seek pollution-reducing projects within the county, and further provides that the District shall prioritize funding for local projects.[20] Our analysis, however, indicates that for FY 2017-18 and FY 2018-19 the District directed the vast majority of its emission reduction funds—for which the OGERA is by far the largest source—to pollution-reducing projects outside of Kern County.[21] We believe this spending is contrary to the requirements and intention of Mitigation Measure 4.3-8 and the OGERA. The SREIR must describe how OGERA funding decisions are made, provide a full accounting of where OGERA fund monies have been spent to date, describe the County's outreach efforts to find pollution-reducing projects within the county, and evaluate why the County's efforts have been unsuccessful. Further, the SREIR should identify and evaluate options to insure that OGERA funds are spent locally in Kern County.

Fifth, the County can and should prioritize OGERA spending on pollution-reducing projects that directly benefit those community members who experience disproportionate socioeconomic and pollution burdens. Mitigation Measure 4.3-8 identifies a list of pollution-reducing projects that may be supported by OGERA funding, including "[f]unding lower-emission equipment and processes for *local businesses, schools, non-profit and religious institutions, hospitals, city and county facilities*."[22] Rather than funding such community interests, it appears that the overwhelming majority of OGERA funds have been directed to projects that exclusively or primarily provide benefits for the agriculture and oil industries. For example, in FY 2017-18 and FY 2018-19, most OGERA funds were spent on replacing agricultural tractors, heavy-duty trucks, and wheel loaders with cleaner versions.[23] In comparison, during the same period, the District spent fee monies on just one community-benefitting project—replacing 18 old public school buses.[24]

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[20] OGERA Section 1.3(c).

[21] We reviewed publicly available information regarding mitigation projects funded by a combination of Indirect Source Review (ISR) and voluntary emissions reduction agreement (VERA) funds (collectively "ISR-VERA" projects). Among the many VERA projects, the OGERA provides the vast majority of funds to the District. The OGERA accounted for approximately $6.25 out of more than $9 million, or 69.4 percent, of money collected by all VERA funds in FY 2017-18. *See* SJVAPCD 2017 Annual Report - Indirect Source Review Program at 5-7. The OGERA accounted for approximately $18.4 out of $20.3 million, or 90.8 percent, of money collected by all VERA funds, in FY 2018-19. *See* SJVAPCD 2018 Annual Report - Indirect Source Review Program at 10 at 9-10.

[22] AR000240 (emphasis added).

[23] *See* SJVAPCD 2017 Annual Report - Indirect Source Review Program at 5, 7, Appendix A; SJVAPCD 2018 Annual Report - Indirect Source Review Program at 9-10, Appendix A.

[24] *Id*. at 7, Appendix A.

This failure to fund community benefit projects is inconsistent with Mitigation Measure 4.3-8 and should be addressed in the SREIR. The SREIR must 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. Additionally, the SREIR should identify and evaluate options to insure that more OGERA funds are spent on pollution-reducing projects that directly benefit the community members who face the most direct impacts from oil and gas development.

III. The County must revise its cumulative health risk assessment.

The Court of Appeal concluded that Kern County violated CEQA by failing to recirculate the original EIR after it released a lengthy cumulative health risk assessment just a few days before the Board of Supervisors voted to approve the Project. Consequently, the court directed that the cumulative health risk assessment must be recirculated in conjunction with any revised EIR. Slip Opinion at 130-32. Further, the court cautioned that the cumulative health risk assessment must not be treated a mere "post hoc justification" of the earlier conclusions reached by the EIR regarding the Project's health impacts. *Id*. at 131.

Consequently, the County may not rely on the cumulative health risk assessment in its current form. As an initial matter, the County must revise the assessment to correct the numerous errors and omissions described in the November 6, 2015 report that Dr. Phyllis Fox prepared for Shute, Mihaly & Weinberger.[25] Additionally, given that five years have passed since the cumulative health risk assessment was released—and the science on both the health effects of air pollution generally and oil and gas activity development has advanced considerably during that time (*see infra*)—the County must update the cumulative health risk assessment to reflect such new, relevant information.

IV. Water Supply

The Court of Appeal held that the EIR's treatment of water supply impacts and mitigation did not meet CEQA's requirements. According to the court, the County unlawfully deferred mitigation for the Project's impacts by adopting measures that lacked specific, mandatory performance criteria, and by delaying implementation of mitigation until after the Project's activities commence. *King,* 45 Cal.App.5th at 855-64. The court specified that, if the County chooses to readopt the Project, it must develop lawful mitigation measures for the Project—based on an updated analysis of the Project's water supply impacts. *Id.* at 845, fn. 15, 899-900.

In revising its analysis of mitigation measures to address water supply impacts, the County must not repeat the error of the original EIR and merely defer to the ongoing planning processes unfolding pursuant to the Groundwater Sustainability Management Act (SGMA). Measures adopted pursuant to SGMA may not be adopted rotely because CEQA imposes higher and more specific analytical and mitigation obligations.

[25] AR15581-85.

The County's revised analysis must also account for significant information that was omitted or ignored in the original EIR. In particular, the County must include a detailed analysis of the Project's localized impacts, including identification of all intended and potential water sources for Project activities in discrete oil fields and agricultural areas, and address the environmental impacts of exploiting those sources. The SREIR should also assess the Project's localized impacts on other water users, including the risk of water rationing and dry wells. In conducting these analyses, the SREIR can and must account for the 2012-2014 drought.

V. The County must consider new information pertaining to other environmental impacts.

A subsequent or supplemental EIR must consider new information when one or more of three events occur: "(a) Substantial changes are proposed in the project which will require major revisions of the environmental impact report[;] (b) Substantial changes occur with respect to the circumstances under which the project is being undertaken which will require major revisions in the environmental impact report[; or] (c) New information, which was not known and could not have been known at the time the environmental impact report was certified as complete, becomes available."[26]

Here, in the time since the Board adopted the Ordinance and certified the original EIR in November 2015, new scientific evidence has demonstrated the impacts of oil and gas activity to be substantially greater than the EIR acknowledged. Consequently, the County's new CEQA process must not only reexamine the portions of the EIR found legally deficient by the Court of Appeal, it 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.

a. Circumstances under which the Project is being undertaken will require major revisions in the environmental impact report.

Circumstances have changed significantly since the County certified the EIR in 2015. The COVID-19 global pandemic has caused serious disruption to daily life and has shone a spotlight on health impact disparities. Multiple studies have found that exposure to higher amounts of air pollution also increases a population's vulnerability to the coronavirus. A major study of air pollution and COVID-19 mortality in the United States found that exposure to even a small increase in fine particulate matter ($PM_{2.5}$) was linked to an 8% greater chance of dying from COVID-19.[27]

The global economic downturn has also further called into question the justification for fast-tracking thousands of new well permit approvals, when demand for oil and gas is at historic lows. The price of oil plummeted to negative prices recently, exposing the speculative nature of the oil and gas industry. A new wave of oil company bankruptcies has begun and increases the

[26] Public Resources Code § 21166.

[27] Wu, Xiao et al., Exposure to air pollution and COVID-19 mortality in the United States, medRxiv (April 5, 2020) ("Xiao 2020"), https://doi.org/10.1101/2020.04.05.20054502; see also Friedman, Lisa, *New Research Links Air Pollution to Higher Coronavirus Death Rates*, N.Y.Times, April 17, 2020, https://www.nytimes.com/2020/04/07/climate/air-pollution-coronavirus-covid.html.

threat that producers will attempt to avoid their legal obligation to plug and abandon the nearly 107,000 active oil and gas wells across the state.[28] By one estimate, the cost of plugging and abandoning these wells would be about $9.1 billion.[29]

The world also has come five years closer to catastrophic, irreversible climate change without meaningful action to curb greenhouse gas emissions by amounts necessary to keep warming within 1.5 degrees Celsius. Temperatures in California have increased and the trend will likely continue unless greenhouse gas emissions are significantly reduced in the near future. Wildfires, floods, heatwaves, vector-borne diseases, and species extinction caused and/or exacerbated by climate change have intensified the need to closely examine the context in which the Ordinance is being proposed.

Circumstances have also changed due to the large number of studies, as discussed below, that document significant harms from oil and gas operations that the original EIR minimized or altogether ignored.

b. Significant New Information Must Be Considered.

Since 2015, multiple studies have shown that oil and gas operations have greater impacts than the original EIR acknowledged. These potential harms must be analyzed as part of any supplemental EIR.

1. Impacts to Wildlife

In 2019, there were more than a dozen major oil and wastewater spills in the Cymric oil field alone. These spills had significant impacts on wildlife. As a result of a 1.3 million gallon surface expression in the Cymric 1Y area, several bird fatalities were confirmed.[30] Oil is routinely released at the surface in Kern County and, in 2020, the California Department of Fish and Wildlife acknowledged that it is common to see oil-covered wildlife in the region.[31] The SREIR must analyze the impacts to wildlife using newly available information.

2. Soil Contamination

Since 2015, Kern County has experienced multiple events resulting in massive soil contamination. The Cymric 1Y spill contaminated large quantities of soil; remediation crews

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[28] California Council of Science and Technology, Orphan Wells in California: An Initial Assessment of the State's Potential Liabilities to Plug and Decommission Orphan Oil and Gas Wells, (Jan. 2020) p. ix., *available at* https://ccst.us/reports/orphan-wells-in-california/.

[29] *Id.*, p. x.

[30] California Dept. of Fish and Wildlife, Cymric Incident Update 10/11/19, *available at* https://calspillwatch.wordpress.com/tag/cymric-oil-field-incident/.

[31] Thomas Cullen, Administrator, Office of Spill Prevention and Response, Department of Fish and Wildlife, speaking at the January 27 joint oversight hearing of the Senate Natural Resources and Water and Assembly Natural Resources Committees: Oversight of the Cymric Oil Spill and California Oil & Gas Policy, 2:13:28 to 2:16:10, *available at* https://www.senate.ca.gov/media/joint-hearing-senate-natural-resources-water-assembly-natural-resources-20200127/video.

hauled the soil to hazardous waste facilities due to the contamination from oil and wastewater.[32] The SREIR must evaluate impacts to soil incorporating this recent information.

3. Groundwater Contamination

The US Geological Survey has published a number of studies that found contaminants from oil and gas activity migrated to nearby groundwater sources.[33] The SREIR must review recent studies to include in its analysis of impacts to surface and groundwater resources.

The SREIR also must include an analysis of the potential impact of steam injection activity on groundwater. CalGEM amended its regulations in 2019 to allow injection pressures above the fracture gradient.[34] Since then, more than a dozen large spills have occurred in Kern County oil fields. These "surface expressions" bring oil and produced water to the surface, potentially polluting surface water or areas that experience seasonal precipitation and drainage. The injection may also migrate underground and endanger nearby groundwater resources.

4. Climate Change

New information regarding the impacts of climate change has become available. Many studies highlight the major role that fossil fuel production plays in bringing us closer to serious consequences of climate change, including triggering more frequent and severe droughts, forest fires, floods, heatwaves, and other extreme weather. The International Panel on Climate Change published its Fifth Assessment Report in 2019. Other studies have increased our understanding of climate change impacts caused by oil and gas development. The SREIR must include an updated analysis of climate change impacts caused by the addition of tens of thousands of new wells in Kern County.

5. Health Impacts

New research has added to our understanding of the adverse health impacts of living close to oil and gas activity.[35] In addition, as noted above, air pollution increases vulnerability to coronavirus. The SREIR—within but not limited to the cumulative health risk assessment—must reevaluate health risk assessments to incorporate this new information regarding both direct impacts from air pollution and the indirect impacts related to mortality rates during pandemics.

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[32] Goldberg, Ted. State Says It Has No Idea How Long It Will Take to Clean Up Chevron's Kern County Oil Spill, KQED, Aug. 23, 2019, *available at* https://www.kqed.org/news/11769242/chevron-kern-county-cymric-mckittrick-oil-spill-clean-up.

[33] *See, e.g.*, McMahon, P.B. et al., Occurrence and sources of radium in groundwater associated with oil fields in the Southern San Joaquin Valley, California, 53 Environmental Science & Technology 9398-9406 (2019).

[34] *Compare* 14 Cal. Code Reg. §, 1724.10(i) (2018) *with* 14 Cal. Code Reg., § 1724.10.3 (April 1, 2019).

[35] *See, e.g.*, McKenzie, Lisa M. et al., Childhood Hematologic Cancer and Residential Proximity to Oil and Gas Development, 12 PLoS ONE 2: e0170423 (2017).

6. Air Pollution

Recent studies show air pollution can travel long distances and remain in high concentrations. The SREIR must evaluate recent air pollution studies and update its analysis of air quality impacts to account for this new information.

7. Risks from Idle and Abandoned Wells

Recent reports have confirmed that Kern County has a large number of idle wells that need to be properly plugged and abandoned. Statewide, there are tens of thousands of idle wells and "marginal wells" that produce less than 5 barrels of oil per day. These wells pose a risk to water, air, climate, and public safety by acting as potential conduits for pollutants while the well sits idle.

By one estimate, it would cost close to $9.1 billion to close and remediate all 107,000 existing wells in California. Despite these risks and the large financial liability, the amount of financial resources that the industry has set aside for remediation is a fraction of what it would cost to properly plug and abandon these wells. As the largest oil-producing county, Kern County could see major fiscal impacts if companies attempt to walk away from their remediation responsibilities. Adding tens of thousands of new wells will only increase the potential financial liability to taxpayers if oil companies continue to drill new wells without setting aside enough money to pay for proper plugging and abandonment.

8. Cumulative Impacts

The EIR must update and revise its cumulative impacts analysis to include projects that have been commenced or proposed in Kern County as well as oil and gas projects statewide since the original EIR certification.

9. Efficacy of Mitigation Measures

The County now has nearly five years of Ordinance implementation experience. Thus, it can describe and evaluate the extent to which the original EIR's mitigation measures have been effective at reducing impacts. In the SREIR, the County must disclose (1) which mitigation measures have been applied to permits (2) how the County determined which measures should apply in each case, (3) to what extent the selected mitigation measures were effective in reducing impacts, (4) which measures failed to adequately reduce impacts of a project, and (5) what steps the County has taken to ensure mitigation measures are being properly implemented by operators.

* * * * *

Your consideration of these comments is much appreciated.

Sincerely,

Hollin Kretzmann
Center for Biological Diversity

Chelsea Tu
Caroline Farrell
Center on Race, Poverty & the Environment

Jose Mireles
Comité Progreso de Lamont

Saul Ruiz
Comité de Lost Hills en Acción

Anabel Marquez
Committee for a Better Shafter

Estela Escoto
Committee for a Better Arvin

Colin O'Brien
Byron Chan
Earthjustice

Elly Benson
Sierra Club

ATTACHMENT A

Teams Live Event Scoping Meeting Instructions

Introduction: In compliance with the Governor's Executive Order, the California Department of Public Health's guidelines on gatherings regarding COVID-19, and Kern County Local Emergency Declaration, the scoping meeting required by the California Environmental Quality Act Guidelines will be conducted online utilizing Microsoft Live Events to allow Agencies and Interested Parties to comment on the preparation of the Draft Supplemental Environmental Impact Report for Revisions to the Kern County Zoning Ordinance for Oil and Gas Local Permitting.

If you are having trouble participating in the Microsoft Live Event please email Julie Williams at williamsj@kerncounty.com

Meeting Date and Time: Wednesday May 13, 2020 at 1:30 pm PST

Link to join: **https://tinyurl.com/y93r92b3**

Spanish Language Translation: Spanish language translation services will be provided in two ways.

Microsoft Live Events Closed Caption – Closed Captions are available in Spanish by clicking on the  at the bottom right of the Presentation Screen. To select Spanish language closed captioning click on the gear icon located next to the closed captioning icon as shown . The County of Kern cannot ensure the accuracy of translation through Microsoft's Live Event closed captioning service.

Live Interpretation via Conference Call – To listen to a Live Interpreter call (224) 501-3412, Access Code: 408-162-717. Attendees will need access to 2 devices to watch the Live Event and listen to the Live Interpretation. Live Interpretation will only be available for Staff's Presentation, <u>no verbal comments will be received during the event</u> therefore, the Live Interpreter will not have the ability to translate questions or comments from Attendees.

Participating in the Virtual Scoping Meeting

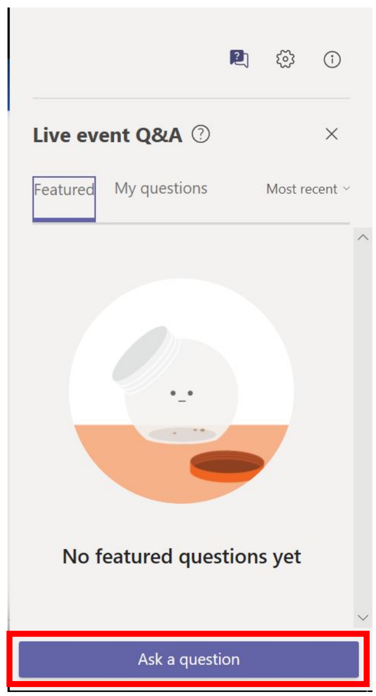
Participating: To join the Virtual Scoping Meeting paste the URL above into your web browser address bar. The URL will direct you to a Microsoft Teams Home Page that will give you the following 3 options: Download the Teams App; Sign-In using your Microsoft Log-In; Join Anonymously. Choose any of these options to join the meeting.

Please note the following:

- The time needed to download the Teams App may vary depending on a number of factors including your internet or data connection speed and the device memory capacity.
- If you have the Teams App already downloaded on your device the meeting will automatically open in your Teams App.
- If joining the meeting from a mobile device, Safari is not a supported browser. We recommend you use an internet connected computer for the best experience.
- For more information about supported browsers, device requirements and more, please visit the Microsoft Office article at the following link:

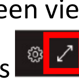
Commenting: Commenting on the scope of the Draft Supplemental Recirculated Environmental Impact Report can be accomplished by providing written comments to Cindi Hoover, Lead Planner, at hooverc@kerncounty.com or by mail at Kern County Planning and Natural Resources Department, 2700 "M" Street, Suite 100, Bakersfield, CA. 93301.

During the virtual Scoping Meeting, questions can be submitted via the Q&A tab (shown below) on the "Right Pane" of the Presentation Screen. The Q&A tab should also be used by Interested Parties and Agencies to submit, for the record, their participation and intent to provide written comments. No verbal comments will be accepted during the virtual Scoping Meeting.



FAQs

Q: I don't see the "Ask a Question" Button on the Presentation Screen, how do I ask a question?

A: The "Right Pane" where the Q&A panel is located may not be available in full screen viewing mode. To change from full screen viewing mode press either the Esc key or the minimize arrows  at the bottom right corner. Next click on the Q&A icon  at the top of the "Right Pane". The Q&A Panel should now open.

Q: Is there a limit to how long my question can be using the Q&A Panel?

A: Yes, a maximum of 2,400 characters per question are allowed by Microsoft.

Q: Are questions and comments anonymous?

A: Questions may be submitted anonymously or you may provide your name to show with the question. For more information on using the Q&A tool please visit the Office Support article at the following link:

Q: I keep getting a prompt to download the Microsoft Teams App, do I need to download the App?

A: If you are using a supported web browser such as Chrome, Firefox, or Edge you do not need to download the Microsoft Teams App. Please see the Microsoft Live Events support article at the following link for information about supported browsers, and device requirements.

https://support.office.com/en-us/article/attend-a-live-event-in-teams-a1c7b989-ebb1-4479-b750-c86c9bc98d84

Q: If I already have the Microsoft Teams App downloaded on my device will the virtual Scoping Meeting Live Event open in my app?

A: Yes, if you have the app the event will open in your Teams App. Be sure you are using the Q&A panel in the "Right Pane" to ask questions or submit your name for the record and not the Teams Chat feature on the left of the screen.

Q: How can I provide verbal comments for the record?

A: While we recommend you provide written comments via the email or the mailing address below, verbal comments may be submitted by phone to Cindi Hoover, Lead Planner, at (661) 862-8629.

ATTACHMENT B

Re: Scoping Meeting May 13, 2020

Lorelei Oviatt <Loreleio@kerncounty.com>
Mon 5/11/2020 5:32 PM
To: Chelsea Tu <ctu@crpe-ej.org>; Cindi Hoover <hooverc@kerncounty.com>
Cc: Craig Murphy <Murphyc@kerncounty.com>

Hi Chelsea,
Thank you for your response. We will place this email in the record as your position.

We are not disadvantaging anyone as no one can comment verbally. This is a scoping meeting and not a community meeting or hearing on the project. It is to solicit agencies and interested parties on the scope of the EIR. Comments regarding this issue and any matters you want included in the EIR can be submitted over the course of the full 30 days review period at any time in writing. Please note we are not required to respond to those in writing specifically but to include them in the EIR and consider them in preparing the Draft Supplemental Recirculated EIR.

If you provide written comments before the hearing, such as these, they will not be read outloud as that is not the purpose of the scoping meeting. They will absolutely be part of the record.

If there are questions on the process that you enter into the Q & A chat during the meeting, we will read those questions about the process and answer them.

While you are free to leave a voice mail, we don't take voicemail comments for the record or transcribe them for the EIR process. There is no requirement under CEQA that we accomodate such verbal comments for the Notice of Preparation or the Draft SREIR. Certainly both the Planning Commission Hearing and Board of Supervisors will include an opportunity for verbal comments.

As for translation we are not accepting your request. As confirmed by the Appeals Court CEQA does not require Spanish translation of any of these EIR documents.

Thank you for your questions.

Sincerely,

Lorelei H Oviatt, AICP
Director
Kern County Planning and Natural Resources
2700 M Street Ste 100
Bakersfield, CA 93301
661-862-8866

From: Chelsea Tu <ctu@crpe-ej.org>
Sent: Monday, May 11, 2020 4:59 PM
To: Cindi Hoover <hooverc@kerncounty.com>
Cc: Lorelei Oviatt <Loreleio@kerncounty.com>; Craig Murphy <Murphyc@kerncounty.com>
Subject: Re: Scoping Meeting May 13, 2020

Hi Cindi:

Thank you for your email, and for letting me know more about your thinking.

In general, the County should open this scoping meeting for oral comments by the public to ensure that it allows for the meaningful public participation and informed decision-making that CEQA mandates.

Low-income residents and communities of color experience disproportionate environmental and health impacts from oil and gas activities in Kern County. However, the County's current meeting set up not only restricts the general public's ability to provide oral comments, it also places low-income and Spanish speaking/non-English speaking residents at a significant disadvantage from being able to meaningfully participate in the meeting.

We therefore request that all members of the public be allowed to provide oral comments by phone and through the Teams App. Opening a phone line for questions and comments during the meeting is necessary to allow residents who do not have the financial means to access a computer and/or Internet to meaningfully participate.

We appreciate that the County will provide a phone line for the public to listen to the meeting in Spanish, as many residents in Kern County are monolingual or primarily Spanish speakers.

Since the County will provide the live interpretation line, we request that those who call into the line be able to provide oral comments or ask questions in Spanish, and have their questions or comments be interpreted and shared in English during the scoping meeting. We do not believe the County would need to make any technological changes in order to meet this request. We also strongly encourage that the County provide two-way Spanish and English live interpretation throughout the entirety of this meeting, and for future meetings on this matter.

Relatedly, we appreciate that the public can call the County to share oral comments outside of the scoping meeting. **We would like to confirm that the public can also call you to submit oral comments before and after the meeting, through at least May 29 at 5pm. We also want to ensure that the comments that you receive in Spanish will be translated into English and considered by the County.**

Finally, we request that the County translate the notice of preparation and all future materials related to the Oil and Gas Ordinance and the supplemental EIR into Spanish, and publicly share the relevant materials in both English and Spanish, prior to any relevant meetings.

Please feel free to give me a call at 510-717-9092, or let me know if there is a time today or tomorrow you could chat.

Thank you, Chelsea

Chelsea Tu
Senior Attorney
Center on Race, Poverty & the Environment
Office: 415-346-4179 x 304
Cell: 510-717-9092
5901 Christie Avenue Suite 208
Emeryville, CA 94608

From: Cindi Hoover <hooverc@kerncounty.com>
Sent: Monday, May 11, 2020 10:56 AM
To: Chelsea Tu <ctu@crpe-ej.org>
Cc: Lorelei Oviatt <Loreleio@kerncounty.com>; Craig Murphy <Murphyc@kerncounty.com>
Subject: Scoping Meeting May 13, 2020

Hi Chelsea,

I received your voicemail regarding participating in the Scoping Meeting for the NOP of the Draft Supplemental Recirculated EIR for Revisions to the Kern County Zoning Ordinance (2020 A) for Oil and Gas Local Permitting. The purpose of the Scoping Meeting is to allow for agency comments on the scope of the Draft Supplemental Recirculated EIR. We are opening the Scoping Meeting up to community members as a courtesy but this is not a community meeting. We have used the tools available to accommodate the public but due to limitations of the technology, we are unable to change the format of the Scoping Meeting. Please contact me with any further questions or technical issues regarding participating in the Scoping Meeting.

Respectfully,
Cindi Hoover, *Planner 3*
Advanced Planning
Kern County
Planning and Natural Resources Dept.
2700 M Street, Ste 100
Bakersfield CA 93301
ph (661) 862-8629
fax (661) 862-8601
email: hooverc@kerncounty.com

SHUTE, MIHALY & WEINBERGER LLP

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RACHEL B. HOOPER
Attorney
Hooper@smwlaw.com

May 27, 2020

Ms. Cindi Hoover
Lead Planner
Kern County Planning & Natural
Resources Dept.
hooverc@kerncounty.com

Re: Notice of Preparation of Draft Supplemental Recirculated Environmental Impact Report (SCH#2013081079)

Dear Ms. Hoover:

We represent King and Gardiner Farms, LLC (KGF) in connection with the proposed project entitled "Revisions to Title 19 – Kern County Zoning Ordinance (2020-A) Focused On Oil and Gas Local Permitting" (Project). As you know, the Court of Appeal found significant flaws with the Environmental Impact Report (EIR) for this Project, and has directed that the County be ordered to revise its environmental analysis in far-reaching and substantial ways. *See King and Gardiner Farms, LLC v. County of Kern* (2020) 45 Cal.App.5th 814 ("*King*"). We submit the following comments on the County's Notice of Preparation of the Draft Supplemental Recirculated Environmental Impact Report (NOP), to ensure that the County closely follows the court's detailed directives regarding the revised analysis.

1. Analysis of Water Supply Impacts and Mitigation.

The Court of Appeal held that the EIR's analysis of mitigation for the Project's water supply impacts violated CEQA. Specifically, the County unlawfully deferred mitigation for the Project's impacts by adopting measures that lacked specific, mandatory performance criteria, and delayed implementation of the mitigation until after the Project's activities commence. *King,* 45 Cal.App.5th at 855-64. The court required that, if the County chooses to readopt the Project, it must both (a) revise its analysis of mitigation for the Project, and (b) update its analysis of the Project's water supply impacts. *Id.* at 845, fn. 15, 900.

The court gave explicit guidance regarding the required update of the EIR's water supply analysis. *Id.* at 899-900. It specifically noted that the formation of local groundwater sustainability agencies and the adoption of groundwater sustainability plans constitute "significant new information" that the revised EIR must address. *Id*. at 899. It further cited new legislation from 2017 requiring applicants for new wells to provide more information and greater transparency about the wells' water use. *Id.* The court concluded: "[T]he information about groundwater supply and use has increased since the preparation of the draft EIR and that information will have lessened the uncertainty described in the draft EIR [regarding the Project's groundwater impacts]." *Id*. at 900.

Accordingly, the County's Supplemental Recirculated EIR (SREIR) must thoroughly revise its water supply analysis to account for this new information. Further, because the information reduces, if not eliminates, uncertainties with respect to the availability and sources of groundwater to serve the Project, the County should expand its discussion to include a detailed analysis of the Project's localized impacts. Previously, the County had defended the EIR's broad-brush, regional analysis by claiming that it was infeasible to analyze the Project's impacts on local water supplies. Now, the court has required that the County reconsider this stance and contemplate a finer-grained analysis in light of the new information. *See id.* at 845, fn. 15 ("Whether the updated information will warrant an analysis of impact to water supplies at a level other than the subareas used in the original EIR is a question that must be decided in the first instance by the County in its role as lead agency.")

The SREIR's analysis of localized water supply impacts should identify all intended and potential water sources for anticipated development/permitted activities in discrete oil fields and agricultural areas, and address the environmental impacts of exploiting those sources. This would include the Project's impact on individual water districts, local aquifers and water recharge areas, and groundwater banking programs. It should analyze, in particular, the Project's potential to affect groundwater tables in smaller subareas focused on agriculturally rich portions of the County. The SREIR should also assess the Project's localized impacts on other water users, including the risk of water rationing from local water districts and wells running dry as a result of lowered groundwater tables.

Finally, the court held that the EIR's analysis of water supply impacts must be updated to account for the 2012-2014 drought. As the court explained, "[t]he revised discussion of water supply impacts must be updated; providing that updated information and describing the new baseline conditions necessarily will take account of the conditions created by the drought." *Id.* at 851, fn.19. Of course, the SREIR's analysis cannot be limited to conditions present in 2012-2014, but must account for conditions existing at the time of its preparation. For example, the SREIR must consider the Project's impacts in the context of the present, extremely dry period. *See, e.g.,* https://www.latimes.com/california/story/2020-03-19/the-west-is-in-an-expanding-20-year-drought-that-a-march-miracle-will-do-little-to-change. Inexplicably, the NOP does not acknowledge the need to update the EIR's drought information.

2. Analysis of Noise Impacts and Mitigation.

The Court of Appeal found that the County's analysis of noise impacts was fundamentally flawed, obscuring the full extent of the Project's effects. Specifically, the EIR failed to analyze whether the Project's permanent or temporary increases in ambient noise levels in the Project vicinity would result in a significant environmental impact. Instead, the County analyzed only whether Project-related noise would exceed a "maximum" standard of 65 decibel (dB) that was set forth in the County's general plan. As the court explained, "[t]he EIR's exclusive reliance on the [65 dB maximum] metric does not provide a complete picture of the noise impacts that may result from the project." *Id.* at 893.

The court's opinion includes a vivid illustration of the EIR's deficient approach. Under the EIR's reasoning, a 20-dB increase at a site with existing noise levels of 44.8 dB would not be deemed significant. By contrast, a 2-dB increase at a site with existing noise levels of 63.9 dB would be significant. The court concluded: "The EIR does not provide a rational explanation for this approach to environmental *change.*" *Id.* (emphasis in original).

Accordingly, the SREIR must revise the County's earlier noise analysis to account for the Project's increase in ambient noise levels. In the process, the County must select a quantitative standard against which to measure the significance of these impacts. While the court did not prescribe a specific metric the SREIR must use as its threshold of significance, it noted that a "5-dBA increase is a common threshold of significance for noise increases when the ambient noise level is less than an upper boundary specified in planning documents or noise ordinances." *Id.* at 892, citing *Mission Bay Alliance v. Office of Community Investment & Infrastructure* (2016) 6 Cal.App.5th 160 and *Gray v. County of Madera* (2008) 167 Cal.App.4th 1099. Notably, both Brown-Buntin Associates, the County's noise expert, and Charles M. Salter Associates (Salter), KGF's noise expert, proposed this exact metric. Given the routine use of the metric, we urge the County to adopt a 5-dB increase over ambient noise levels as the threshold for evaluating the significance of the Project's increases in temporary and permanent noise. If the

County rejects the 5-dB threshold commonly used and recommended by its consultant, it should explain why this threshold was not chosen.

In addition, the County must revise the EIR's discussion of mitigation for the Project's noise impacts. The EIR's failure to address the significance of Project-related noise increases over existing levels fatally undermined its analysis of mitigation. The mitigation proposed by the EIR consisted largely of setback requirements that would avoid only average noise levels above 65 dB. Now, the SREIR must identify mitigation that could reduce or avoid any significant Project-related increases in noise levels above ambient conditions. As the court recognized, the County's existing data indicate that these impacts will be found significant. *See King*, 45 Cal.App.5th at 893 (noting that at one monitoring site, Project will cause 20-dB increase). As the County designs mitigation to address these impacts, it should consider the feasible measures recommended by KGF's noise expert. *See* Letter from Salter dated Sept. 9, 2015.[1]

Finally, as the court recognized, the County must consider updating the EIR's description of baseline conditions for noise. *King*, 45 Cal.App.5th at 900. The prior noise study was conducted in 2015, and circumstances have likely changed since then. If the County declines to update the baseline information, the SREIR must document its reasons for that decision. *Id.* ("Whether the baseline[] used in analyzing noise impacts … should be updated presents questions that cannot be resolved on the record before this court. Accordingly, the County should resolve these questions in the first instance and explain its decision in the revised EIR released for public comment.")

3. Analysis of Mitigation for Conversion of Agricultural Land.

The Court of Appeal determined that the County's finding that the Project's conversion of agricultural land would be mitigated to a less-than-significant level was not supported by substantial evidence. *King*, 45 Cal.App.5th at 872-79. Specifically, the court invalidated the County's sole mitigation measure for farmland conversion (MM 4.2-1) on the grounds that three of the four options for satisfying its requirement did not provide effective mitigation. *Id.* The court further held that the County failed to provide a reasoned analysis of its grounds for rejecting other mitigation proposed by local farmers, who suggested clustering oil infrastructure and operations sited on working farms. *Id.* at 879-82; *see also id.* at 882 ("[W]e conclude the proposal for clustering presented a type of mitigation that would lessen, but not eliminate, a significant environmental impact.").

[1] KGF reserves the right to propose additional mitigation measures during the present administrative process for the SREIR and the Project.

The NOP misleads the public by apparently ignoring the full scope of the court's holding invalidating the County's mitigation measure, MM 4.2.1. This measure specified that the applicants could mitigate impacts from farmland conversion by:

> (a) purchasing or funding agricultural conservation easements "or similar instrument[s],"
> (b) purchasing credits from an agricultural farmland mitigation bank or "an equivalent agricultural farmland preservation program" managed by the County,
> (c) restoring agriculture to productive use by removing legacy equipment, or
> (d) participating in "any" agricultural land mitigation program adopted by the County that provides "equal or more effective mitigation."

Id. at 871.

The court found that options a, b, and d were wholly ineffective. *Id.* at 872-79. The NOP, however, appears to assume that the court invalidated only option a. *See* NOP at 23 ("The Appellate Court determined that agricultural conservation easements do not mitigate farmland conversion impacts.") When the County prepares the SREIR, it must recognize that options b and d were also unsupported.

Accordingly, the SREIR must consider additional mitigation measures, including the clustering of wells when feasible, for reducing the Project's conversion of agricultural land. *See King*, 45 Cal.App.5th at 829-30, 895. As the County prepares its analysis, we urge it to review the mitigation measures proposed during the prior administrative process. *See, e.g.,* Letters from this firm dated Sept. 11, 2015 and Nov. 5, 2015, and Letter from Holly King dated Sept. 28, 2015.

Finally, the court cautioned that, as the County revises its analysis of mitigation for farmland conversions, it must consider updating the EIR's description of baseline conditions. *See King,* 45 Cal.App.5th at 900. After all, any analysis of a mitigation measure's efficacy is undermined if the EIR's assessment of the impact is inaccurate – and that assessment depends on an accurate baseline. Given that the prior analysis of farmland conversions was conducted in 2015, the EIR's baseline description likely requires revision. If the County declines to update the baseline information, SREIR must document its reasons for that decision. *Id.* ("Whether the baseline[] used in analyzing … conversion of agricultural land should be updated presents questions that cannot be resolved on the record before this court. Accordingly, the County should resolve these questions in the first instance and explain its decision in the revised EIR released for public comment.")

4. Recirculation of Cumulative Health Risk Assessment/Multi-Well Health Risk Assessment.

In the unpublished portion of its opinion, the Court of Appeal held that the County erred in failing to recirculate its 1,691-page Cumulative Health Risk Assessment (aka Multi-Well Health Risk Assessment), which had been released only five business days before the Board certified the EIR and approved the Project. The court concluded that members of the public and other government agencies did not have "a meaningful opportunity to scrutinize the Multi-Well Health Risk Assessment and evaluate its merits and shortcomings." Slip Opinion at 131.

The NOP acknowledges that the County must recirculate the Multi-Well Health Risk Assessment. We urge the County to (a) update this key analysis before its release, to reflect updated PM2.5 data and other relevant new information (*see id.* at 141, fn. 49), and (b) correct the errors and omissions previously noted by this firm and KGF's air quality expert Phyllis Fox. *See* Letter from this firm dated Nov. 6, 2015 with attached Fox report.

Thank you for considering these comments.

Very truly yours,

SHUTE, MIHALY & WEINBERGER LLP

Rachel B. Hooper

Rachel B. Hooper

1238930.6

SIERRA CLUB
KERN-KAWEAH CHAPTER

P.O. Box 3357
Bakersfield, CA 93385
May 27, 2020

VIA ELECTRONIC MAIL

Kern County Planning and
Natural Resources Department
Attn: Cindi Hoover, Lead Planner
2700 "M" Street, Suite 100
Bakersfield, CA 93301

Re: NOTICE OF PREPARATION OF A DRAFT SUPPLEMENTAL RECIRCULATED ENVIRONMENTAL IMPACT REPORT (SCH # 2013081079)

Dear Planners:

The Kern-Kaweah Chapter of the Sierra Club offers a number of comments about the County's NOP for the SREIR for Revisions to Title 19- Kern County Zoning Ordinance (2020-A) Focused on Oil and Gas Local Permitting.

CEQA Guidelines Appendix F goals call for "decreasing reliance on natural gas and oil" and "increasing reliance on renewable energy sources", and climate scientists tell us that leaving large portions of fossil fuels in the ground is the only way to avoid the worst impacts of climate change. The SREIR should acknowledge, embrace, and address these goals by discouraging further oil and gas extraction.

The SREIR should discuss why it is not described as a program EIR rather than a project EIR given the lack of site-specific data, the vast geographic area the EIR purports to cover, and in order to enable Kern County to address issues that are undergoing changes more easily addressed in the future.

Water Supplies

The NOP states that the SREIR will only address feasible revisions to water supply mitigation measures. The SREIR will also be brought up to date with information about the implementation of SGMA. To be adequate, the SREIR must also include up to date information about the availability of surface water deliveries pursuant to the State Water Project and Central Valley Project. Moreover, the SREIR must specifically address water supply impacts from the implementation of the Bay Delta Water Quality Control Plan and how that plan could affect surface water deliveries to Kern County farmers and municipal water users.

Comments on the use of agricultural conservation easements at a one-to-one ratio for the conversion of farmland to urban use:

- The County has argued in the past that it cannot legally require agricultural easements as mitigation for farmland conversion and is therefore giving the developer several options in its mitigation measure. The decision, San Mateo County Coastal Landowners' Association, et al. v. County of San Mateo et al (1995) 38 Cal.App.4th 523, 549 held that "Civil Code §815.9 does not restrict the ability of a local governmental entity to require the dedication of an easement under other provisions of the law", such as CEQA. In light of the San Mateo case, the County cannot insist that it is legally precluded from requiring the acquisition of agricultural conservation easements. The SREIR should require agricultural conservation easements as partial mitigation for farmland loss.
- By law and definition, an agricultural conservation easement (ACE) must be a perpetual easement. **The SREIR must require the ACE to be a perpetual easement**.
- Such easements must be monitored and enforced, and **the SREIR must require that an endowment must be set up to pay for monitoring and enforcement expenses.**
- In order to be confident that the ACE will be appropriately enforced, ACEs are normally held by an accredited land trust. **The SREIR must**

require that the easement holder must be an accredited land trust.

- The mitigation measure only states that the ACE must be on farmland of equivalent quality as that of the land being converted. The developer could satisfy this condition on the cheap by buying an unnecessary conservation easement on farmland that is so far away from urban areas that there is little or no development pressure on it. This circumstance would undercut the presumed intention of the measure to preserve farmland from conversion to urban use and protect the area's agricultural economy. **The SREIR must require qualifying mitigation land to be of equal quality and under somewhat similar development pressure.** One way to do this would be to require an appraisal of the conservation easement value on the project's farmland and then require mitigation land to have easement value of at least, say, 75% of the project land's conservation easement value.

- The measure would allow land outside of the local area to be used as mitigation land, even land outside the San Joaquin Valley. While we concur that the problem of farmland conversion is a global one, there are several reasons to require mitigation land to be local, if not in Kern County at least in the southern San Joaquin Valley. For one thing, if mitigation lands are far flung, it will be very hard to monitor and enforce the condition. A local land trust working with local land is much more accountable to the local public good than is one many hundreds of miles away. In addition, preservation of local farmland helps to protect our own area's very important agricultural economy and helps makes it possible for local consumers to buy fresher locally grown produce. Of course, the aesthetic worth of farmland as open space is something that we should value locally. Since the impact is here, we fail to see why we should provide these benefits to Madera County or Fresno County or Imperial County when we could equally well provide them closer to home. **The SREIR must require qualifying mitigation land to be within the southern San Joaquin Valley in close proximity to the converted farmland.**

- In order to reduce this significant and unavoidable impact and to be more certain that the mitigation measure satisfies CEQA requirements for farmland conversion mitigation, **the SREIR should address the potential that the mitigation ratio be higher than**

one-to-one, that perhaps three acres of equally good, equally at risk farmland be preserved elsewhere for every acre of agricultural land converted to urban use.

The SREIR must address these issues.

We have significant concerns regarding the reuse of produced water . At a minimum, the SREIR should address the following issues:

- It is likely that produced water varies in composition from one oilfield to the next. The SREIR must separately list the oilfield chemicals, the salts, the heavy metals, and other chemicals that are contained in produced water from each of the Kern oilfields. The EIR should identify acceptable concentrations of each of these chemicals and set performance criteria to ensure groundwater quality is not affected by oil and gas operations.
- Since it is likely that the produced water from each of the Kern oilfields varies in quality, the SREIR must address the feasibility of using the produced water from each of the Kern oilfields for agricultural irrigation based on compliance with standards referred to above.
- Does the chemical composition of oilfield produced water vary with the well depth?
- Will edible crops grown on farmland irrigated with produced water from each oilfield be safe to eat? The EIR should discuss the potential impact of expanded oil and gas operations on agricultural operations, in detail.
- Over the years when farmland is irrigated with produced water, it is likely there will be a buildup in the soil of oilfield chemicals, salts, heavy metals, and other chemicals that are contained in produced water. The SREIR must address the long-term impact of the buildup of these minerals in the farmland soil including the possibility that in the long term the farmland irrigated with produced water will become less fertile or unusable or affect livestock
- The EIR should consider whether the use of produced water for irrigation (rather than injected back into the ground where it came from,) could cause subsidence in the area of the drill site or elsewhere. The SREIR must address this potential for subsidence resulting from the use of produced water for irrigation, list sites where

such subsidence is likely to occur, and determine the potential amount of such subsidence at these sites.

- Produced water from the oilfields is sometimes blended with regular irrigation water before being used on farmland. The SREIR must determine on an annual basis how much regular irrigation water will be needed in order to mix with oilfield produced water for irrigation use. What are the long-term competing uses for this regular irrigation water? What uncertainties are associated with long-term regular irrigation water supplies? What are the environmental impacts associated with securing and delivering these regular irrigation water supplies? For example, what is the impact of water diversions on endangered species? What mitigation is feasible for these environmental impacts?
- If, as a result of the use of produced water for irrigation, lands that are not currently being used for agriculture are proposed to be newly expanded for farmland, the SREIR should address the sustainability of this process, particularly in light of the Sustainable Groundwater Management Act and the plans resulting from SGMA. How would such expansion of farmland acreage affect local Groundwater Sustainability Plans?

According to the attached NRDC Fact Sheet, "An NRDC analysis of oil and gas wells and California Environmental Protection Agency data for Kern County reveals:

- **One in three residents lives within one mile of an oil or gas well.** That's more than 290,000 people, or 35 percent of the county's population.
- **Nearly half of the people who live within a mile of an oil and gas well also live in communities most vulnerable to pollution.** This accounts for roughly 122,000 people—or 15 percent of the county's population—who are already grappling with health threats from air pollution, drinking water contamination, and exposure to pesticides.
- **Communities of color shoulder the overwhelming majority of the burden.** More than 3 out of 4 people who live within a mile of a well and in one of the state's most polluted communities are people of color.

Expanding oil production in Kern County could create additional health threats from air and water pollution faced predominantly by communities of color, particularly Hispanic/Latino communities. For many of the people already living with oil and gas wells—and at ground zero for new drilling activity—these threats are piled on top of a heavy burden of environmental contamination."

The SREIR must address the environmental justice and community health aspect of oil production in Kern County. Moreover, the County must provide copies of the SEIR in Spanish and ensure all information about the SEIR is made available in Spanish.

The science behind the health impacts of the chemicals and emissions from fossil fuel production on our bodies and our children's bodies is clear. There is growing scientific evidence that links how close you live to an oil and gas well to a host of health impacts, including cancer, premature mortality, asthma, and other respiratory illnesses.

According to the attached document *Existing scientific literature on setback distances from oil and gas development sites* by Nicole J. Wong, MPH, " Based on the current available research, a 2,500-foot setback recommendation is on the lower end of the range of distances where research has determined harmful health and quality of life impacts of toxic emissions and exposures." A buffer of 2,500 feet between oil and gas operations and the places where people live, work, and learn is necessary to protect the health and safety of our communities, and **the SREIR should require increased setbacks, at least 2500 feet**.

Studies of millions of people whose exposure never exceeded the current standards, shows that breathing particle pollution, even at levels below the current standards, increases mortality rates. For example:

- A study of 61 million Medicare beneficiaries in America found higher particle pollution was associated with higher mortality, even among those never exposed to levels above the current standards.
- A Canadian study of over 2 million people, where the average exposure was well below the current standards, found that air pollution even at these levels was associated with premature death.

Given the alarming PM2.5 levels in Kern County, the SREIR must investigate this health crisis in Kern County and must require locally oriented conditions that will effectively address this health crisis. The County must prepare a public health risk assessment to evaluate the regional and local impacts of PM 2.5 emissions. Any multi-well health risk assessment must specifically address the health impacts associated with PM2.5 emissions.

In the four years since the County started issuing permits, nearly $89 million has been received for air pollution mitigation. Nevertheless, Kern County has retained its slot as the most-polluted county in America for year-round PM2.5 particle pollution and is near the top of the list for the most polluted county for ozone pollution, according to the latest American Lung Association report. **The SREIR should address the following concerns**:

- Has all of the $89 million been spent?
- The SREIR should list all specific projects that have been funded by this $89 million, and it should list the funding amounts for each project.
- The SREIR should specify where the funding has been spent. In particular, it should specify how much of the funding has been spent in Kern County and in each of the counties in the jurisdiction of the SJVAPCD.
- Since Kern County has retained its air pollution top slot, the SREIR must explain why the $89 million air fee has been so ineffective, and it must contain conditions that will make it more effective.
- Since Kern County air pollution is a local health and EJ crisis, the SREIR must specify that air pollution mitigation funding be spent near the impact, preferably in Kern County but at least in the southern San Joaquin Valley.

The original EIR did not address PM2.5 pollution, nor did it contain mitigation measures specific to PM2.5 pollution. The SREIR should require some PM2.5 mitigation that is over and above the measures contained in the original EIR.

In order to help address PM2.5 pollution (as well as other criteria pollutant and GHG pollution), the County should be encouraging the use of non-polluting electric vehicles (EVs). **The SREIR should require the oil industry to fund**:

- Replacement of the County vehicle fleet with EVs, where feasible.
- Construction of EV charging stations on appropriate County properties. Some of these EV charging stations should be fast-charging stations open to the public.
- So as to charge EVs with clean energy, parking lots should be partially retrofitted with covered structures whose roofs contain solar photovoltaic panels (PV).
- The retrofit of solar PV on existing County buildings, where feasible.

The SREIR should require oilfield use of solar heating or PV to fuel steam injection operations.

Please place the Sierra Club on the distribution list for the SREIR for Revisions to Title 19- Kern County Zoning Ordinance Project to receive any noticing of meetings, hearings, availability of documents, and to receive the environmental documents. We prefer email communications and electronic formatting of documents. Thank you for your consideration and for the opportunity to comment.

Sincerely,

Gordon L. Nipp

Gordon L. Nipp, Ph.D.

Vice-Chair

gnipp@bak.rr.com

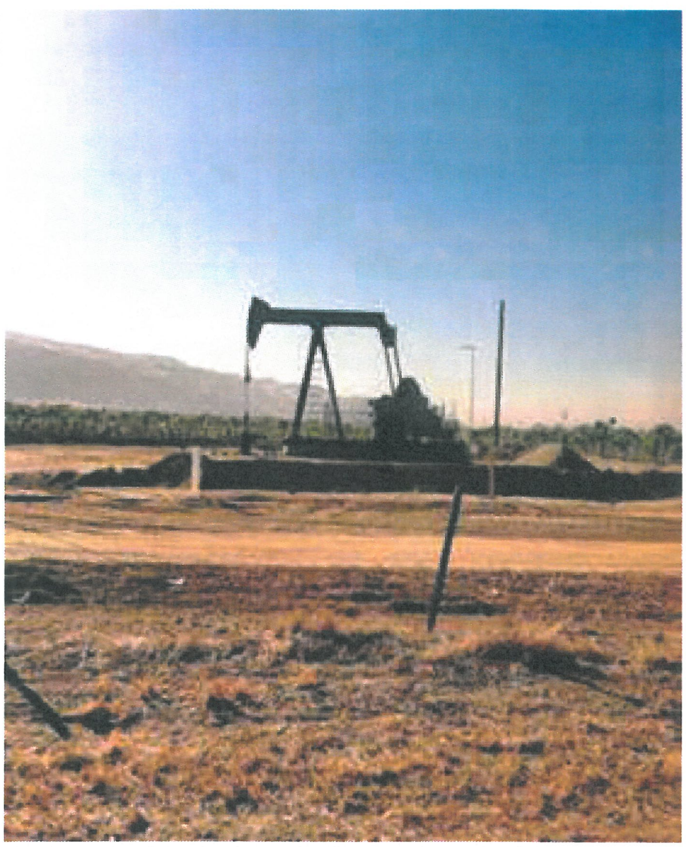
661-872-2432

SEPTEMBER 2014
FS:14-09-B

Fracking Threatens Health of Kern County Communities Already Overburdened with Pollution

New analysis reveals thousands of oil and gas wells concentrated near places already among the most vulnerable to pollution and predominantly communities of color

Kern County is the epicenter of California's oil and gas production with more than 63,000 of the state's 84,434 active and new oil and gas wells—nearly 75 percent.[1] In addition to large conventional oil reservoirs, Kern County sits atop part of the Monterey Formation, which is targeted for unconventional oil production using fracking and other stimulation methods.



Oil well in Kern County

Of the rural county's population, 39 percent live in communities ranked among the most at risk from environmental pollution in California.[2] In addition, many oil and gas wells are located in places that are already shouldering a disproportionately high share of the burden from air, water, and soil pollution from existing industrial activity, including higher rates of illnesses (like asthma) that are linked to pollution.[3] These places are also predominantly home to communities of color.

As the oil and gas industry explores how to increase production using fracking and other controversial extraction techniques in Kern County, these communities are at the greatest risk for the potential health impacts. This includes impacts that have been linked to respiratory and neurological problems, birth defects, and cancer.[4]

An NRDC analysis of oil and gas wells and California Environmental Protection Agency data for Kern County reveals:

- **One in three residents lives within one mile of an oil or gas well.**[5] That's more than 290,000 people, or 35 percent of the county's population.
- **Nearly half of the people who live within a mile of an oil and gas well also live in communities most vulnerable to pollution.** This accounts for roughly 122,000 people—or 15 percent of the county's population—who are already grappling with health threats from air pollution, drinking water contamination, and exposure to pesticides.

NRDC

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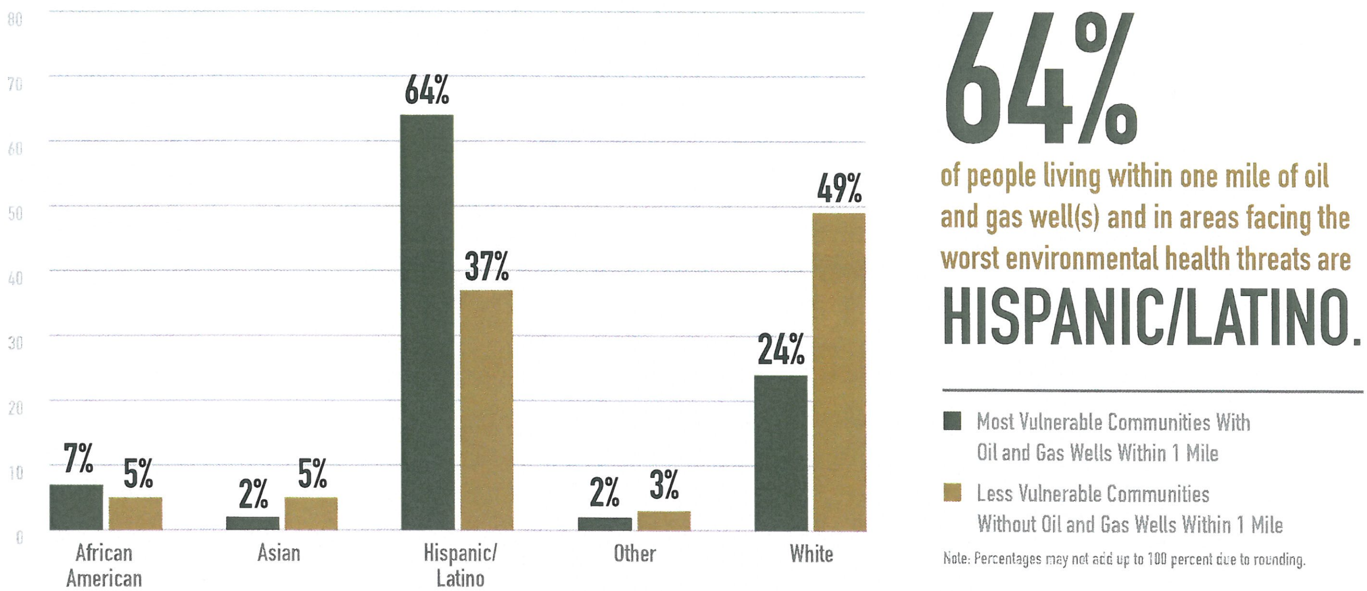
www.nrdc.org
www.facebook.com/nrdc.org
www.twitter.com/nrdc

Figure 1: Demographics of Kern County Residents Most Vulnerable to Pollution* and Within 1 Mile Distance to Oil and Gas Wells



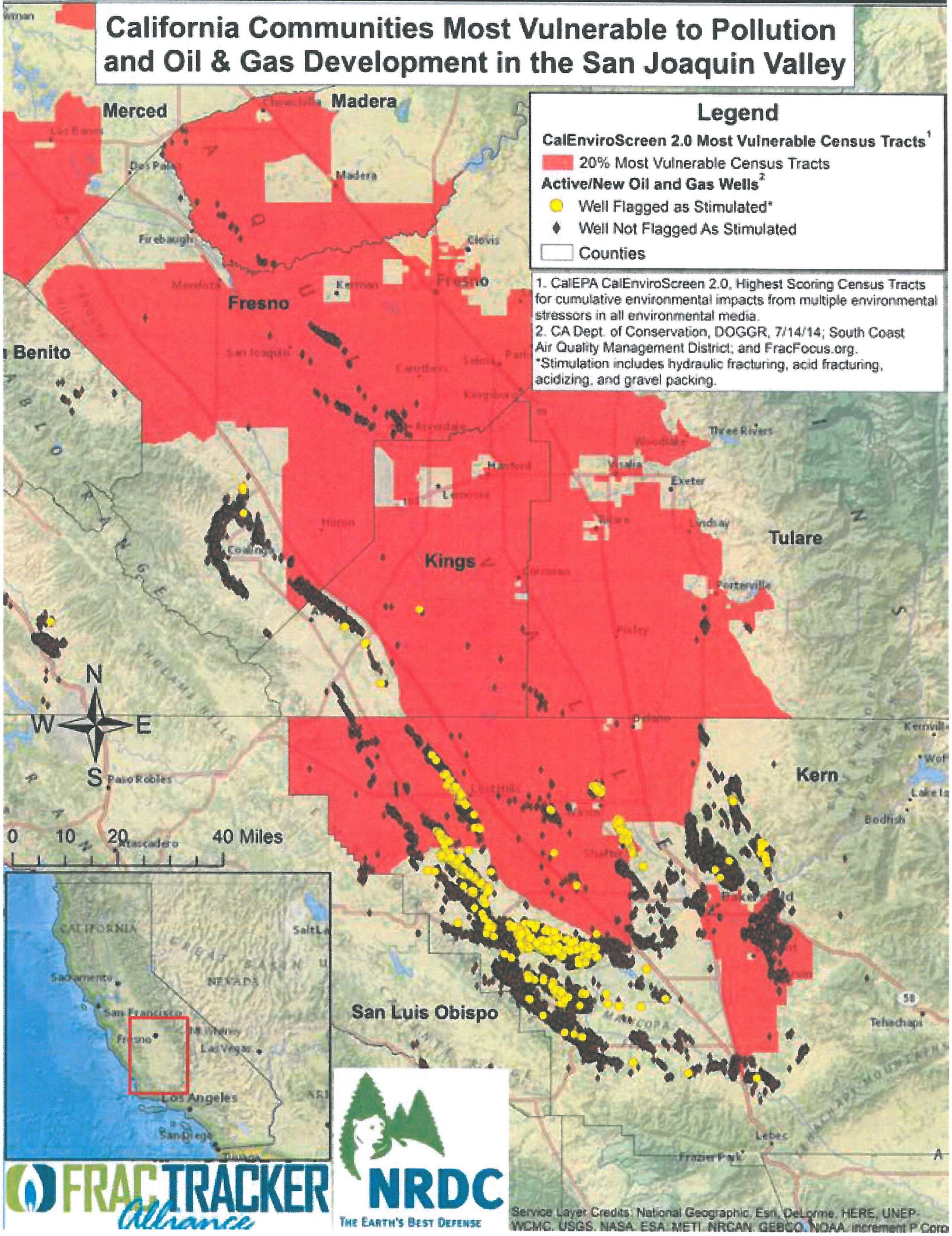
*California Office of Environmental Health Hazard Assessment (OEHHA), "CalEnviroScreen Version 2.0," oehha.ca.gov/ej/ces2.html.

- **Communities of color shoulder the overwhelming majority of the burden.** More than 3 out of 4 people who live within a mile of a well *and* in one of the state's most polluted communities are people of color (see also Figure 1).
- **Kern County currently has 63,430 active and new oil and gas wells.**[6] Of these, 6,141 are newly permitted and at least 2,361 have already been stimulated using hydraulic fracturing, acidizing, or other stimulation methods. New activity is also concentrated in the county and accounts for 591 of the 596 well stimulation notices that were filed by well operators between December 2013 and July 2014.

Expanding oil production in Kern County could create additional health threats from air and water pollution faced predominantly by communities of color, particularly Hispanic/Latino communities. For many of the people already living with oil and gas wells—and at ground zero for new drilling activity—these threats are piled on top of a heavy burden of environmental contamination.

NRDC's analysis underscores the need for a time-out on fracking and other dangerous oil and gas stimulation methods in California to allow for a full evaluation of their risks and determine how to protect against them. It also highlights the importance of defending a community's right to restrict or prohibit fracking within its own borders—rather than waiting for the state to act.

Southern San Joaquin Valley showing the density of active and new oil and gas wells as of July 2014 and the 20 percent most vulnerable census tracts according to the CalEnviroScreen 2.0 released in August 2014



This map was created using datasets generated by the California Division of Oil, Gas and Geothermal Resources (DOGGR), the South Coast Air Quality Management District (SCAQMD), FracFocus.org, and the California Environmental Protection Agency (CalEPA). The full report, along with a description of the methods and tables identifying the most impacted areas, are available here: www.nrdc.org/health/california-fracking-risks.asp.

Endnotes

1 CA Division of Oil, Gas and Geothermal Resources (DOGGR), GIS Mapping, "AllWells" database, www.conservation.ca.gov/dog/maps/Pages/GISMapping2.aspx (accessed July 14, 2014) and "Well Stimulation Treatment Notices Index," www.conservation.ca.gov/dog/Pages/IWST_disclaimer.aspx (accessed July, 2014). South Coast Air Quality Management District Rule 1148.2 "Oil and Gas Wells Activity Notification," xappprod.aqmd.gov/r1148pubaccessportal/Home/Index (accessed July, 2014). FracFocus Chemical Disclosure Registry, fracfocus.org/ (accessed July, 2014). More details on data extraction can be found in Appendix I of the main report www.nrdc.org/health/california-fracking-risks.asp.

2 CalEPA, Office of Environmental Health Hazard Assessment, "CalEnviroScreen 2.0 data and report," oehha.ca.gov/ej/ces2.html (accessed August 18, 2014).

3 EPA, "Asthma Triggers: Gain Control," www.epa.gov/asthma/triggers.html (accessed 09/02/2014).

4 John L. Adgate, Bernard D. Goldstein, Lisa M. McKenzie, "Potential Public Health Hazards, Exposures and Health Effects from Unconventional Natural Gas Development," *Environmental Science & Technology*, February 2014, doi:10.1021/es404621d. Lisa M. McKenzie, et al., "Birth Outcomes and Maternal Residential Proximity to Natural Gas Development in Rural Colorado," *Environmental Health Perspectives*, 2014, doi:http://dx.doi.org/10.1289/ehp.1306722. Lisa M. McKenzie, et al., "Human Health Risk Assessment of Air Emissions from Development of Unconventional Natural Gas Resources," *Science of the Total Environment* 424 (2012): 79–87, doi:10.1016/j.scitotenv.2012.02.018.

5 We used a quarter mile distance in urban areas while for the statewide calculation we used a one mile distance to take into account the lower population density in rural areas. These distances were chosen to reflect common, and understandable, measures of proximity because there is a limited, and inconclusive, literature evaluating distances and health risks. Additionally, some pollution is regional and can impact populations not immediately proximal.

6 This includes wells classified in DOGGR's "AllWells" database as New and Active Oil and Gas wells. Active Oil and Gas wells include wells not plugged according to DOGGR's standards and therefore may be sites for new stimulation or act as conduits for pollution. The classification may differ from the *WellStatus* code in the same database.

Existing scientific literature on setback distances from oil and gas development sites

Nicole J. Wong, MPH November 2017 (version 2)

Background: Need for an LA Relevant Setback

The current body of peer-reviewed scientific literature has a small but growing set of studies investigating the relationship between the proximity of modern oil and gas extraction nearby communities and health impacts. The published studies that have examined this relationship have considered health outcomes, exposure to toxic health risks, and discussed whether current setback requirements in various states are adequate to ensure the health and safety of people who live, work, play, and learn near these facilities. These studies were conducted primarily in lower population density communities and states. Yet, the majority of these studies find a positive correlation between distance of a home from an active oil or gas well and adverse health outcomes. The closer people live to oil and gas wells, the more likely they will be exposed to toxic air contaminants and the more elevated their risk of associated health effects.[1] Most of these distances are measured at a half-mile to a mile (See Table 2). Distances in Los Angeles are much closer. No peer-reviewed studies to date have investigated the relationship between the proximity of oil and gas development and health outcomes in California, nor have any studied this issue in the U.S. urban context. In Los Angeles alone, about 1.7 million people live within 1 mile of an active oil or gas well, and of that group, more than 32,000 people live within 100 m (about 328 feet) of an oil or gas well.[2]

Overview of Report Contents

> The population density in South Los Angeles is about ***133 times greater*** than the populations investigated in the existing literature.

A total of 14 studies and publications were considered for this report that investigated the health and quality of life impacts and exposures of unconventional natural gas development proximate to residences. Of the 14 studies and publications, 6 considered the distance of an active well to place of residence (Table 1), while the remaining 4 considered the concentration of wells proximate to residences (Table 2). Four of the publications are studies and non-peer reviewed reports that have setback recommendations or relevant considerations for a safe setback margin (included in Table 1). The distances considered in this report range in setback recommendations and findings from 1,500 to 6,600 feet. Among the peer-reviewed studies that specified where samples and data were collected, the average population density was about 150 people per square mile. To compare, the population density for the City of Los Angeles is about 50 times greater at 8,092.3 people per square mile. In neighborhoods like South Los Angeles that is home to several active oil drilling sites, the population densities are up to more than 20,000 people per square mile.[3] The population density in South Los Angeles is about **133 times greater** than those of the populations investigated in the existing literature. Table 1 lays out the peer-reviewed studies included in this report, ordered by the safe setback distance each study considered. Advocacy groups in Los Angeles have called for a 2,500-setback law to protect the health and safety of nearby residents. **Based on the current available research, a 2,500-foot setback recommendation is on the lower end of the range of distances where research has determined harmful health and quality of life impacts of toxic emissions and exposures.**

Oil and Gas Extraction Methods

During much of the early and mid 1900's, conventional methods of extracting oil depleted most of the oil fields throughout the country. In Los Angeles, only 10% of oil field reservoirs can be recovered by conventional means.[2] Now, in order to access resources that are deeper or more difficult to recover than those that have been recovered historically, oil industry has pursued new technologies in "unconventional" or "enhanced oil recovery" methods.[2,5] These methods include steam, water, and/or chemical injection, hydraulic fracturing, acidization, and gravel packing.

Although the existing research has primarily focused on health impacts and toxic emissions from unconventional natural gas development, many of the same chemicals of concern used in so-called unconventional activities are used in routine activities such as well maintenance, well-completion, or rework on both conventional oil and natural gas wells.[6] There are many applications of hazardous chemicals in oil and gas development, and in fact the routine operational chemical use data is less available than that for unconventional chemical use activities.[6]

In Los Angeles, many of the extraction facilities utilize unconventional techniques, such as acidizing with hydrochloric and hydrofluoric acid, directional drilling, and gravel packing which involves use of tons of carcinogenic silica sand. Many of the oil fields in Los Angeles produce both oil and gas at a relatively equal ratio. Among the top ten producing oil fields in the City of Los Angeles, which include Beverly Hills, Wilmington, and Las Cienegas oil fields, the ratio of gas to oil production is about 0.91.[7] Therefore, the existing research in other parts of the country holds relevance for the nature of oil and gas extraction in Los Angeles.

Health and Quality of Life Impacts

The consequences to health from oil and gas activity investigated in the reviewed studies include birth outcomes, asthma, other respiratory and dermal impacts, pediatric sub-chronic non-cancer and chronic hazard indices, unhealthy noise levels, and various associated health symptoms. Among the existing research, the greatest distance to oil and gas activity investigated was 2 km (6,561 feet) where exposure to hydrogen sulfide combined with VOCs were detected.[7] The shortest distance measurement studied was 1,500 feet and this study found significantly more reports of health symptoms in households within 1,500 feet of an active well. The health symptoms included throat irritation, sinus problems, nasal irritation, eye burning, severe headaches, loss of sense of smell, persistent cough, frequent nose bleeds, swollen painful joints.[9] Rabinowitz, et al. (2015) found an increased number of reported upper respiratory symptoms and skin conditions among residents who lived less than 1 km (3,280 feet) from an active well when compared with residents who lived more than 2 km (6,561 feet) from an active well.[10] McKenzie, et al. (2012) found elevated risk of health effects from natural gas development for residents living less than half a mile from wells. They primarily considered the subchronic non-cancer hazard index, which was primarily driven up by exposure to trimethylbenzenes, xylenes, and aliphatic hydrocarbons, and chronic hazard index measurements, which were driven up by benzene exposure.[11]

Another dimension of health impacts related to oil and gas development is noise levels. Boyle, et al. (2017) conducted a pilot study investigating the 24-hour noise levels of a compressor station relative to residential homes both indoors and outdoors.[12] His study determined that homes up to 600m away (about 1,968 feet) experienced outdoor noise levels that exceeded the U.S. Environmental Protection Agency's recommended limit of 55 dBA 100% of the time.[12] In addition to these punctuated periods of noise, the regular day-to-day operations at the site cause what has been described as "buzzing" throughout the night makes it difficult to sleep. Recent studies have increasingly focused on "non-auditory" effects of noise on health including annoyance, sleep disturbance, daytime sleepiness, hypertension, cardiovascular disease, and diminished cognitive performance in school children.[13] Many residents living in close proximity to oil and gas development sites in Los Angeles routinely complain of noise from routine operations.

Air Quality and Toxic Exposure

Three of the studies investigated levels of volatile organic compounds (VOCs) and endocrine disrupting chemicals that exceeded regulatory agency minimum standards. Haley, et al. (2016) discussed how exposures of hydrogen sulfide combined with VOCs could produce potentially new harmful exposures that could be detected at distances up to 2 km (about 6,561 feet).[7] Macey, et al. (2014) investigated several jurisdictions with setback regulations for oil and gas operations and conducted air monitoring sampling to examine if the setbacks were adequate.[14] The findings revealed high concentrations of carcinogenic VOCs at distances greater than the setback regulations, including formaldehyde at 2,591 feet and benzene up to 885 feet away from wells. The study also discussed how health-based risk levels that most regulatory agencies rely on for setting limits on air emissions are very limited in providing a sense of the human health impacts.[14] The risk level standards do not account for more vulnerable subpopulations like children and the elderly. Additionally, the number of compounds that are required for monitoring and toxicity reporting is relatively small when considering the vast number of chemicals required for oil and gas operations.[14] Kassotis, et al. (2014) found elevated levels of endocrine disrupting chemicals in water sources 1 mile away from oil and gas operations with known spills or incidences.[15] The study noted that near one of the investigated facilities contaminated by endocrine disrupting chemicals (EDCs), some of the animals in the area were no longer producing live offspring.

The findings revealed high concentrations of VOCs at greater distances than the setback regulations, including formaldehyde at 2,591 feet and benzene up to 885 feet away from wells.

Explosion Risk and Hazards

Haley, et al. (2016) considered the minimum distance that might be required in case of a blow-out or explosion event by investigating historical evacuation data.[7] For example, an explosion in the Barnett Shale in northern Texas produced a 750-foot burn crater.[16] Their findings determined that the average evacuation zone for such incidences is 0.8 miles, or 4,224 feet. A blowout in Wyoming County, PA required a 1,500 foot evacuation zone, which required the evacuation of only 3 families.[17] Considering that in Wyoming County the population density was only 71.2 people per square mile[1816] compared to a densely populated neighborhood in South Los Angeles with a population density of over 20,000, if a similar event were to happen, the same distance of 1,500 feet would require evacuation of 100,743 people. A very recent example of natural gas pipeline explosion accident comes from rural Colorado. On April 17, 2017, a one-inch abandoned pipeline exploded under a home in Colorado, leveled the house, killed two people and badly burned a third person. The gas well head was located just 178 feet from the home.[19]

Dense Population of the City of Los Angeles and Close Proximity to Oil and Gas Facilities Magnifies Health and Safety Risks

Four studies investigated the relationship between health outcomes and the number of wells within a certain radius of residential homes (Table 3). The studies were concerned with birth outcomes and childhood leukemia and were conducted in Pennsylvania and Colorado. The density measures ranged from 3.36 – 125 wells per square mile. To compare to Los Angeles, the four extraction facilities in South Los Angeles that extract from the Las Cienegas oil field, the 2nd largest gas producing field in Los Angeles, each have 22 to 36 oil and gas wells operating less than 100 feet from residential homes. The Inglewood oil field has over 1000 wells operating well within 1 mile of residential homes, recreation parks, and other sensitive land uses.

The studies that investigated poor birth outcomes found that mothers in the sampling population who lived near the highest density of active wells were 1.3 more likely to give birth to a child who had congenital heart defects (CHD) and 2 times more likely to give birth to a child with neural tube defects (NTD),[22] higher incidences of LBW and SGA,[23] and increased rate of preterm birth.[24] McKenzie, et al. (2017) found that increased well density was associated with increased risk for acute lymphocytic leukemia in people ages 5-24.[25]

Delphi Technique

In addition to peer review studies, a consortium of experts in environmental studies and public health have also assessed and considered policy recommendations to address the health and safety consequences of close proximity to oil and gas development. The Environmental Health Project (EHP) is a public health organization that utilized the Delphi Technique to arrive at an expert consensus on an appropriate setback distance for unconventional oil and gas development from human activity.[21] "The Delphi is an accepted method for reaching convergence of expert opinion about a specific topic," and in this study, consensus was defined as 70% agreement of panelists. The process resulted in an 89% participant agreement that 1 to 1.25-mile distance (6,600 feet) from unconventional oil and gas development is an acceptable minimum to protect human health. Additionally, the study recommends greater setback distances for settings where vulnerable subpopulations might gather, such as schools, day care centers, and hospitals.

> …89% participant agreement that **1 to 1.25-mile distance** from unconventional oil and gas development is an acceptable minimum.

Existing setback laws

It is clear that throughout the scientific literature that researchers agree the existing setback laws in various jurisdictions throughout the U.S. are inadequate to protect the health and safety of residents who live, work, and play near oil and gas operations. Existing setback laws range from 150 to 1,500 feet. States like Arkansas, Colorado, and Ohio have varying setback distances from different sensitive land uses.[7,14] Pennsylvania and Texas have state level setback laws for any oil and gas operations near residential land use. Several municipalities in Denton County, Texas, have enforced stronger setback laws. In response to override these municipalities, the Texas state legislature subsequently passed HB40

> …**existing setback laws** in various jurisdictions throughout the U.S. **are inadequate** to protect the health and safety of residents who live, work, and play nearby oil and gas operations.

which preempts regulation of oil and gas operations by municipalities. Haley, et al. (2016) determined that based on historical catastrophic events, thermal modeling, vapor cloud modeling, and air pollution data, these existing setbacks laws are not sufficient to protect potential risks and threats to human health from hydraulic fracturing operations.[7] Macey, et al. (2014) considered the concentration of VOCs in five different states and determined that the setbacks in those states were inadequate to prevent exposure to formaldehyde and benzene.[14] Majority of the established setback laws were typically decided by negotiations between stakeholders, like residents and policymakers, and not supported by scientific, empirical data.[23] The state of Maryland is one example of a jurisdiction that scientifically investigated the health and safety impact of oil and gas operations. In July of 2014, the University of Maryland School of Public Health conducted another study that focused on public health impacts.[26] Among the 52 recommendations that resulted from the investigation, the researchers recommended a minimum 2,000-foot setback between dwellings and well pads and non-electric motor compressor stations. In 2017, Maryland became the second state in the country to ban hydraulic fracturing.[27]

Conclusions

While few studies have investigated the relationship between the proximity of oil and gas operations and human health impacts, this body of literature does highlight a clear public health concern and that existing setback laws are not adequately protecting public health and safety. **The growing body of scientific literature recognizes that a setback distance between oil and gas operations and locations where people live, work, play, and learn are *necessary* to protect human health and safety. Setbacks are especially crucial to protect vulnerable populations, such as children, elderly, and the chronically ill or disabled.** The 2,500-foot setback recommendation incorporates recognition of Los Angeles' population density and the vulnerability of residents, schoolchildren, and the elderly from health hazards and possible disasters related to oil development. The current literature has identified that existing laws are not adequate for low density, rural communities. This finding underscores the need for a stronger setback in Los Angeles' densely populated urban environment. Many of the impacted communities are in close proximity to a large number of wells and other oil and gas development facilities and are already overburdened by exposure to cumulative environmental health impacts from other industrial and transportation sources. These marginalized communities have long endured environmental injustice. **The scientific literature and published reports make a strong case for a far more protective health and safety setback for the City of Los Angeles than currently exists in other jurisdictions, and creates a substantial basis for the 2,500-foot setback proposed by community advocates.**

Table 1. Comparison of studies and reports by distance to active oil and gas wells with consideration to population density.

Green-blue shaded rows are non-peer reviewed reports. Light blue shaded rows are peer reviewed publications that have relevant setback considerations or recommendations.

*Population density values based on 2010 U.S. Census Fact Finder Population density data.

Citation	Health Impact / Exposure Finding	Distance with health / exposure finding impact / recommendation	Converted to feet	Pop Density 2010 of investigated counties/states (residents per sq.mi.)) *
SW Pennsylvania EHP Technical Reports [21]	Delphi Technique	1 to 1.25 mile	6,600 feet	--
Haley, et al., 2016 [7]	Exposure to hydrogen sulfide combined with VOCs could produce potentially new set of exposures - detected at distances of 2 km	2 km	6,561 feet	--
Haley, et al., 2016 [7] & Heinkel-Wolfe, 2013 [14]	Considered blow-out and evacuation data, average evacuation zone was 0.8 miles. Explosion in Barnett Shale produced a 750-ft burn crater. [14]	0.8 miles	4,224 feet	--
Kassotis, et al., 2014 [16]	Elevated levels of endocrine disrupting chemicals in water sources 1 mile from sites that had known spills/incidents - animals no longer produced live offspring… Location: Garfield County, Colorado	1 mile	5,280 feet	19.1
Webb, Ellen, et al. 2017	Literature review on neurodevelopmental and neurological effects of chemicals associated with UOG operations and their potential effects on infants and children. Made a recommended minimum setback of 1.6 km.	1.6 km	5,249 feet	--
Rabinowitz, et al., 2015 [10]	Significant respiratory and dermal impacts Location: Washington County, PA	Less than 1 km	3,280 feet	242.5
McKenzie, Witter, Newman, & Adgate, 2012 [11]	Significantly increased risk of pediatric sub-chronic non-cancer hazard & Chronic hazard indices	Less than ½ mile	2,640 feet	Rural areas and towns, population <50,000 in 57 counties
Macey, et al., 2014 [14]	Monitored high concentrations of VOCs - up to 2,591 ft Location: Counties in 4 states – AR, PA, CO, OH	2,591 ft	2,591 feet	137.45 (average)
2,500 FEET RECOMMENDATION FOR CITY OF LOS ANGELES				8,092.30
University of Maryland School of Public Health 2014 [26]	Recommended min setback distance of 2,000 ft from well pads Location: state of MD	1,000 ft	2,000 feet	594.8
Boyle, et al., 2017 [12]	Unhealthy noise levels Location: Doddridge County, WV	< 600m	1,969 feet	25.7
Steinzor, Subra, & Sumi, 2013 [9]	Significantly higher rates of health symptoms in households within 1,500 ft of an active well Location: 14 counties in PA	1,500 ft	1,500 feet	165.1

Table 2. Studies investigating the relationship of health outcomes and proximity to concentration of wells

Citation	Health Outcome	Measurement Used	Well Concentration/ Density (by wells per sq mile)	Pop Density 2010 of investigated counties/states (residents per sq.mi.)) *
McKenzie, et al., 2017[25]	In rural Colorado, People ages 5-24 had a 3-4 times higher risk for developing acute lymphocytic leukemia Location: state of Colorado	>33.6 wells in 16.1 km or 10 miles	3.36 wells	48.5
Stacy, et al., 2015[23]	Birth outcomes by concentration of wells. Those with 6+ wells within mile had higher incidence of SGA and LBW in SW Pennsylvania Location: 3 counties in PA (Butler, Washington, Westmoreland	6+ wells per 1 mile	6 wells	277.0 (average)
Casey, et al., 2016[24]	Mothers who lived in the highest exposure quartile were 1.4 times more likely to give birth to children who were considered low birth weight (LBW) and smaller than gestational age (SGA). Location: 40 counties in PA – Using state population density	Highest exposure quartile had 124 wells within 20 km; lowest had 8 wells within 20 km	About 10 wells	283.9
South Los Angeles – Jefferson Drill Site (example for comparison)		36 wells within 1 mile	36 wells	21,848
McKenzie, et al., 2014[22]	In rural Colorado, mothers who lived in higher exposure tertile had 1.3 higher chance of giving birth to a child with congenital heart defect (CHD)2.4 higher chance of having Neural Tube Defect. Even in the 2nd tertile of highest exposure, mothers were 1.2 more likely to give birth to a child with CHD. Location:	Highest exposure tertile had 125-1400 wells within a mile, the next highest tertile had 3.63-125 wells within a mile.	125 wells	Rural areas and towns, population <50,000 in 57 counties

*Population density values based on 2010 U.S. Census Fact Finder Population density data.

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From:	Tom Williams
To:	Cindi Hoover; Department, Planning; CD, Kern
Cc:	UNtuk; uduak-joe.ntuk@conservation.ca.gov
Subject:	RE: Comments for Notice of Preparation of a Draft Supplemental Recirculated Environmental Impact Report (SREIR) Title 19 / ZOrd.2020A SCH# 2013081079
Date:	Friday, May 8, 2020 12:05:09 PM

DATE: May 08, 2020, 12 pm

TO: Kern County, Planning and Natural Resources Dept. Attn: Cindi Hoover, Lead Planner

2700 “M” St., Suite 100 Bakersfield, CA 93301 661-862-8629

ATTN.: Comments on the Notice of Preparation: hooverc@kerncounty.com

FROM: Dr. Tom Williams, Sierra Club, Los Angeles and Citizens Coalition for A Safe Community

4117 Barrett Rd., Los Angeles, CA 90032 323-528-9682 ctwilliams2012@yahoo.com

CC: planning planning@kerncounty.com

Kerncd kerncd@kerncounty.com

CalGEM

SUBJECT: Revision Title 19, Zon.Ord. 2020-A Focused on Oil and Gas Local Permitting (SCH#2013081079)

RE: Comments for Notice of Preparation of a Draft Supplemental Recirculated Environmental Impact Report (SREIR)

Thank you for the transmittal of the Notice of Preparation (NOP) for California Environmental Quality Act (CEQA) process for the Revision of Title 19, Zoning Ordinance 2020-A. I have reviewed and am submitting these initial comments regarding the NOP as I believe they are important and require some modifications/clarifications of the NOP, itself.

Additional comments will be submitted as developed up to May 29.

Comments:

I request that the current CEQA review be changed to a "Draft Programmatic Environmental Impact Report", as is more commonly incorporated into longer term (25+ years) projects of a "planning" and "zoning" process and procedure for such a large area (3700 sq mi).

As indicated on the IS/NOP Title Page, this process is requested by: California Independent Petroleum Association and Western States Petroleum Association Public Records Act and I request all communications between the Department and listed "Requestors" for 01/01/2020 through July 1, 2020.

Please provide subscription process to be notified by emails/web for attending of the virtual scoping meeting, May 13, 2020, 1:30 pm and provide agenda for such virtual scoping meeting directly to all listed "Labels" for "mailing list" on pg. 3-24 at least three (3) days before the virtual scoping meeting on Kern County Planning and Natural Resources website https://kernplanning.com/.

Some initial review comments regarding the content and substance of the IS/NOP:

No scoping document is provided, provide full content Scoping Report including a single listing of Project Objectives and alternatives.

Provide a single statement of quantifiable Project Objectives rather than the dual set and clearly state which take precedence in the consideration of alternatives;

Provide mitigative/compensatory alternatives to each element in consideration.

8/4 The Western Subarea consists of 1,714 square miles…and is generally bounded by the Kern County border on the north and west…. The Western Subarea contains many of the **large-scale oil and gas extraction-level operations** in the project area and includes 37 active oil and gas fields. Five of these oil and gas fields are the largest in California by **production volume**.

Provide definitions and quantitative parameters for "large scale", e.g., >5 wells/acre, -/160ac, -/320ac, or -/640ac.

Provide listings and quantitative and graphical descriptions of "operations", e.g., >5 wells within one square miles

Provide oil&gas related definitions of "extraction" and "production". Kern County historically has been known for both but extraction was generally limited to near-/on-surface oil/tar seeps rather than wells.

"A non-thermal heavy oil production method, using a solvent vapor to reduce viscosity of the heavy oil. The injected vapor expands and dilutes the heavy oil by contact…diluted heavy oil will drain by gravity to the lower horizontal well, to be produced.

12/1 i). Other sections of the Ordinance would be updated by the proposed amendments to ensure consistency with the **MMRP** and other regulatory requirements. 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**,…

Provide MMRP, including all required public meetings to be schedule throughout the program period.

Provide monitoring and revisions of operations during 2018-20 related to MMRP monitoring and mitigation.

Provide oil&gas related definitions and delineations of "extraction districts" and "production districts".

Provide five-year summary tables for extraction and production of oil, gas, water, and any other fluids from such.

13/3 In addition to oil and gas wells, installation and operation of ancillary equipment and facilities are integral components 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… that may be injected as steam or liquid to help **extract the oil**).

13/4 "Tank farms" that include tanks for separating oil and water, and storing oil and water, typically serve several wells and vary in size and distance from wells. **Produced water** collected in tanks is typically reused for further **extraction** purposes, …. Some **produced water** requires treatment prior to reuse for **extraction**, or disposal, and some **produced water** is treated and reclaimed for other purposes.

13/5 **Extraction** technologies include injecting large volumes of water (water flooding) or steam (steam flooding and cyclic steam injection) into **production** strata, ….

Provide definitions of liquids and fluids in O&G operations.

Provide and consistently use "Produced" and "Extract" throughout NOP and all CEQA documents.

As indicate herein, the preparers of the NOP/IS are not apparently experienced/trained in oil and gas operations and documentation, withdraw the current CEQA documents, revise, and recirculate as they are confusing to the general public and O&G reviewers.

14/2 1.4 **Project 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 can be implemented for the purpose of **reducing or eliminating potential significant adverse environmental impacts**, to the **extent feasible…**and, thereby, ensure that current County ordinances implement the Board of Supervisor's policies to **protect** the **health, safety, and general welfare of communities, residents, and visitors.**

As compared to objectives defined by others on pg.16/par.1, provide a revised/combined listing of objectives in a recirculated NOP.

Provide documentation of all mitigation and elimination of significant impacts achieved during 2018-20.

Provide definition of "extent feasible" and whether economic/financial consideration are involved. Provide economic/financial/fiscal/monetary review of all past actions 2015-2020 within the operations of the current Ordinance.

Provide definitions of health, safety, and general welfare and how they have been protected 2018-2020.

14/2 (c) The EIR found that, without mitigation, the Project has the potential to expose **sensitive receptors** to **substantial pollutant concentrations**. The implementation of Mitigation Measures…was found to reduce these impacts to **less than significant levels**. The Appellate Court opinion concluded that separate mitigation and supporting analysis for potential PM2.5 emission impacts was required in the EIR. In addition, the opinion determined that a **Multi-Well Health Risk Assessment** prepared for the Project should have been circulated for public review and comment prior to the certification of the EIR. The SREIR will update the analysis of potential Project impacts from PM2.5 emissions, including the potential exposure of **sensitive receptors** to **substantial PM2.5** concentrations, **consider feasible mitigation measures** for reducing potentially significant impacts, and**, if applicable,** discuss whether such impacts can be **feasibly mitigated**. The SREIR will include a **Multi-Well Health Risk Assessment** for public review and comment, and will **reflect** updated information about PM2.5 emissions in Kern County, **as applicable**.

Provide immediate access and links to the MWHRAssessment and to all 2018-2020 applications of such to wells in Kern County and require review and comment on the entirety of the MWHRA, not just the PM2.5 sections.

Provide definitions, delineations, and graphical relationships of "sensitive receptors" (including households of 25%, 35%, 50% 60%, and 80% of $45,000 annual household incomes, or applicable incomes for the areas involved).

Provide definitions "consider", "if applicable", feasibly mitigated, reflect, and as applicable.

Provide definition of "substantial" PM5 and Black Carbon air pollutants.

Provide review of interactions of BC, PM1.0, PM2.5, H2S, and BTEX and their health implications as were earlier found with suspended particulate and SO2.

Incorporate findings of the CARB SNAPS findings and considerations of O&G emissions from well fields in the South Central Valley.

16/1 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 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 upon 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.

Provide a single listing of Project Objectives and provide a comparison between those of the County and those of the Proponents.

Provide definitions for efficient, streamlined, economically feasible, feasible, adequate protection, employment, prosperity, and other related issues.

Provide supporting economic/financial/fiscal/employment setting, impact assessment, alternatives, and mitigation related to the O&G industry and spere in Kern County and the Project area.

16/4 Several parties appealed the Superior Court judgment….On February 25, 2020, the Appellate Court issued an opinion that upheld the Superior Court 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…." The opinion set aside the previously approved Ordnance amendments and the certification of the EIR. The opinion further directs the County…,to correct the CEQA violations…," to prepare "a revised EIR correcting the CEQA violations," and to **prepare and publish "responses** to the comments…."

As the MWHRA, is specifically an area that did not comply with CEQA and good public practices, Provide all correspondences and communications regarding the non-public circulation, review and comments by the Public and other government agencies, 2015-2020.

Provide a complete document history for the current MWHRA and its application, by project and applicants, and any changes to the Assessment or projects made in such review.

16/5 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 EIR….

As the MWHRA, is specifically an area that did not comply with CEQA and good public practices, Provide all correspondences and communications regarding

the non-public circulation, review and comments by the Public and other government agencies, 2015-2020.

17/1 **(5) Recirculation** of the **Multi-Well Health Risk Assessment** for public review and comment. The SREIR will include…

Multi-Well Health Risk Assessment for public review and comment and

will consider whether the assessment should be revised to reflect updated PM2.5 information, **as discussed in the opinion**.

Not circulated previously nor in this IS/NOP. Provide the original, all revisions of thereof, and current version. Provide listing of all preparers for original and subsequent revisions MWHRA.

Extend current NOP review process til 30 days following access to or circulation of the MWHRA.

26/1 (c) The EIR found that, without mitigation, the Project has the potential to expose **sensitive receptors** to substantial pollutant concentrations. The implementation of Mitigation Measures 4.3-5 and 4.36 was found to reduce these impacts to less than significant levels. The Appellate Court opinion concluded that separate mitigation and supporting analysis for potential PM2.5 emission impacts was required in the EIR.

In addition, the opinion determined that a **Multi-Well Health Risk Assessment** prepared for the Project should have been **circulated for public review and comment prior to the certification of the EIR**. The SREIR will update the analysis of potential Project impacts from PM2.5 emissions, including the potential exposure of **sensitive receptors** to substantial PM2.5 concentrations, **consider feasible mitigation measures** for reducing potentially significant impacts, and, if applicable, discuss whether **such impacts can be feasibly mitigated**. The SREIR will include a **Multi-Well Health Risk Assessment** for public review and comment, and will reflect updated information about PM2.5 emissions in Kern County, as applicable.

Not circulated previously nor in this IS/NOP. Provide the original, all revisions of thereof, and current version.

Provide listing of all preparers for original and subsequent revisions MWHRA.

Extend current NOP review process til 30 days following access to or circulation of the MWHRA.

Define "feasibly mitigated" and provide listing of all 2018-2020 permitting revisions affected by the MWHRA.

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Appendix B

Health Risk Assessments

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Cumulative Health Risk Assessment

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Cumulative Health Risk Assessment
Kern County Final EIR –
Proposed Drilling and Oil and Gas Operations

Prepared by:

Environmental Compliance Solutions, Inc.

171 Pier Avenue #337
Santa Monica, CA 90405

October 2015

Table of Contents

1.0 - PROJECT OVERVIEW

Technical Appendix M-2 was completed in order to evaluate potential cumulative health impacts associated with multiple well drilling operations occurring simultaneously. This cumulative Health Risk Assessment (HRA) has been prepared as part of the Final Environmental Impact Report (FEIR) prepared for the proposed Amendment to Title 19 – Kern County Zoning Ordinance – Chapter 19.98 for Oil and Gas Local Permitting.

California's Office of Environmental Health Hazard Assessment (OEHHA) is tasked with determining the relative toxicity of numerous chemicals and compounds and is also in charge of determining how California's regulatory HRAs will be conducted.

The cumulative HRA conducted for the proposed project followed the OEHHA Guidelines as amended in March 2015. The latest version of the OEHHA Guidance Manual updates the previous version (OEHHA, 2003), and reflects advances in the field of risk assessments along with new more conservative consideration given to infants and children and their associated inhalation rates. The new guidelines are significantly more stringent than the 2003 version and it is this more stringent guideline that was used for the DEIR. Results using the March 2015 OEHHA Guidelines result in calculated risk of more than 300% or 3 times higher than previous calculations using the previous guidelines.

This HRA assumes that up to forty-eight (48) individual 13,000' wells would be drilled in concentric circles around a sensitive receptor. Twelve wells (12) would be 1/8th of one mile away from the school, 12 additional wells would be 1/4th of one mile away, 12 more wells would be 3/4th of one mile away and 12 more would be one mile away. Each well is assumed to have an associated drilling mud sump and emissions from the sump are included in the analysis as well.

While there are not typically operational emissions from a completed well itself, in order to calculate a very conservative health risk assessment, the cumulative HRA assumes that potential well re-work could occur every other year. That would require the use of a workover rig which emits diesel exhaust. The diesel exhaust was also assumed to occur at each of the 48 wells every other year.

2.0 - HEALTH RISK ASSESSMENT OVERVIEW

As recommended by the OEHHA guidelines, HARP2 (CARB, 2015) was used to perform a refined HRA for potential future drilling 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 United States Environmental Protection Agency (USEPA's) AERMOD model and the risk model includes the latest changes made by OEHHA to the Risk Assessment inputs.

In general, risk assessments involve four steps:

1) Emissions Estimations of Hazardous Air Pollutants;
2) Exposure Assessments;
3) Dose-response Assessments; and
4) Potential Health Risk Quantification.

Emissions Estimations of Hazardous Air Pollutants

Emission estimates involve identifying and quantifying emissions of potential regulated toxic substances from each source. OEHHA guidance regarding whether the pollutants are carcinogenic or possibly associated with short-term or long-term non-cancer health impacts was followed. Toxic emissions from each source were then quantified.

“Hazardous air pollutants (HAPs)” is a term used by the federal Clean Air Act (CAA) that includes avariety of pollutants generated or emitted by industrial production activities. HAPs are also referred to as Toxic Air Contaminants (TACs) under the California Clean Air Act of 1988 (CCAA). California listed diesel exhaust or diesel particulate matter (DPM) as a TAC in 1998. 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.

The DPM toxicity number incorporates the cumulative health effects of all of the constituents of diesel exhaust into one risk number. Therefore, the only TAC associated with diesel equipment from well construction and completion is DPM. The primary TACs of concern for this project are diesel exhaust associated with construction equipment and drill rigs.

DPM was analyzed from drilling operations. Drilling operations also include an assumption that a drilling mud sump will be required for each well drilled. Potential fugitive emissions of hydrocarbons (VOCs) can be emitted from drilling mud sumps. Potential health effects from both DPM and VOCs are summarized herein.

This analysis is based on a number of very conservative assumptions; one of which was to assume that all receptor locations contain sensitive receptors.

Sensitive receptors are defined as people that have an increased sensitivity to air pollution or environmental contaminants. Sensitive receptor locations include schools, parks and playgrounds, day care centers, nursing homes, hospitals, and residential dwelling unit(s). Within each sensitive receptor, it was assumed that children were residing at the site. The location of the nearest sensitive receptors to a project site is needed to assess toxic impacts on public health.

Well Drilling Emissions

Seven phases of drilling were considered as detailed below. All particulate matter 10 microns (PM10) in diameter was considered to be toxic DPM. This significantly overstates true emissions as a portion of the PM10 calculated included road dust and other sources of fugitive dust associated with well pad construction, well drilling and completion that are not actually DPM.

A very conservative well depth of 13,000’ was assumed to be drilled in 2017. Using a very conservative approach, emissions from all seven phases were assumed to occur simultaneously. CARB’s OFFROAD emissions estimate model was used to calculate emissions from the primarily mobile and off-road diesel equipment. CARB has extensive regulations for diesel equipment with future compliance dates that will result in significant emission reductions of PM10 over time.

NOTE: CARB’s model includes currently adopted diesel regulations designed to reduce emissions from various off-road and on-road engines. No emission reductions are included in future year calculations for potential reductions from proposed or potential additional regulations that may be required in the future.

Each well evaluation consists of the following phases:

- Land Preparation;
- Drilling Survey;
- Well Drilling;
- Well Completion;
- Well Flowline;
- Pump Unit; and
- Electrical.

Numbers and types of equipment associated with each well depth are listed below. An exact equipment list for each of the seven phases and their associated emissions is included in Appendix A.

Emissions from the drilling mud sump are included in the following table.

Table 1 – Equipment Associated with Well Construction, Drilling and Completion*

Depth Feet	Number of Trucks	Off-Road Construction Equip.	Drill Rig HP totals	Drilling Days
13,000	10	55	3 rigs at 1,040 HP each	43

Table 2 - Annualized 13,000 Foot, 2017 Well Drilling Emissions Including Rework

Source	Compound	Annual Emission lb/year
Drilling	Diesel Particulate Matter (DPM)[1]	784.32[2]
Rework	Diesel Particulate Matter (DPM)[1]	18.24[3]
Drilling Mud Sump[4]	1,2,4 Trimethylbenzene[5]	0.10
	Benzene[5]	0.48
	Cyclohexane[5]	0.10
	Ethylbenzene[5]	0.10
	n-Hexane[5]	4.32
	Toluene[5]	0.48
	Xylenes[5]	0.48
	Hydrogen Sulfide[6]	0.10

[1]PM10 emissions were from Vector Environmental (Feb 2015). All PM10 was assumed DPM.
[2]Annualized emission based on a 70 year exposure.
[3]500 hp Tier 2 diesel engine operating every other year for 9 days, 30 minutes per day, annualized.
[4]Drilling mud emissions were assumed to occur 1 day per year for 70 years. Actual drilling mud emissions from a 13,000 foot well would occur one time only for 43 days.
[5]From SJVAPCD Website: Oilfield Equipment Light Crude Oil Fugitives.
[6]Based on 100 ppmv H_2S.

3.0 - EXPOSURE ASSESSMENT

Exposure assessment includes air dispersion modeling, identification of emission exposure routes and estimation of exposure levels. The modeling estimates ground level concentrations based on an emission rate of one gram per second. This rate is then multiplied by the worst case potential emission rate for each substance to obtain ground level concentrations. In addition to inhalation, potential pathways of exposure to offsite receptors include dermal exposure and ingestion.

HARP2 incorporates the USEPA AERMOD (v14134) model. AERMOD predicts resulting cumulative concentrations from various emission sources. The rural setting was selected in AERMOD for this analysis. AERMOD's terrain processor, AERMAP, was used to incorporate actual terrain elevations for sources and receptors. Five years of meteorological data required for AERMOD was obtained from the SJVAPCD.

SJVAPCD released its updated risk assessment guidance on May 28, 2015. The Hot Spots Analysis and Reporting Program, Release Version 2 (HARP2) software was revised on June 29, 2015 (Version 15180), and again on July 16, 2015 (Version 15197). Version 15197 was used for this HRA.

For the cumulative analysis, the Shafter area was utilized and the Wasco meteorological station data was used.

Source Modeling Parameters

Potential sources were modeled as described in the table below. Both drilling and operational emissions are assumed to occur along a fence line shared by an oil producer and a private residence (i.e., sensitive receptor).

4.0 - 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.

Exposure Pathways

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.

For this analysis, HARP2 requires assumptions that DPM could also be ingested via dermal (skin) absorption, soil ingestion and mother's milk ingestion.

5.0 - SIGNIFICANCE THRESHOLDS

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 20 in one million

6.0 - HEALTH RISK ASSESSMENT RESULTS

Results of the cumulative modeling study indicate results of 9.3 in one million potential cancer risk.

As stated above, the SJVAPCD CEQA threshold for risk is 20 in one million. Therefore, even with the most conservative assumptions including multiple well drilling in close proximity to sensitive receptors, the cumulative impact are less than the 20 in one million significance thresholds and are not considered significant under CEQA.

7.0 - REFERENCES

California Code of Regulations, Title 22, Division 2, Chapter 3, Section 12000 “Safe Drinking Water and Toxic Enforcement Act of 1986.” California regulations can be downloaded at the following link: http://www.oal.ca.gov/.

CARB. 2015. “HARP User Guide.” The document can be downloaded at the following link: http://www.arb.ca.gov/toxics/harp/harpug.htm

SCAQMD. 2007. “General Instruction Book for the 2006-2007 Annual Emission Reporting Program.” The document can be downloaded at the following link: http://www.ecotek.com/aqmd/2006/forms_and_instructions_pdf/0607_GuideBook.pdf

SCAQMD. 2005. “Risk Assessment Procedures for Rules 1401 and 212”. The document can be downloaded at the following links: http://www.aqmd.gov/prdas/pdf/riskassessmentprocedures-v7.pdf and http://www.aqmd.gov/prdas/pdf/attachmentpkg-l.pdf.

SCAQMD. 2005. “Supplemental Guidelines for Preparing Risk Assessments for the Air Toxics “Hot Spots” Information and Assessment Act (AB2588). The document can be downloaded at the following link: http://www.aqmd.gov/prdas/AB2588/pdf/AB2588_Guidelines.pdf.

United States Environmental Protection Agency (U.S. EPA) 2004. User's Guide for the AMS/EPA Regulatory Model – AERMOD, EPA-454/B-03-001.

Meteorological data used by AERMOD was obtained by SJVAPCD for Bakersfield Station 23155.

OEHHA. 2003. “The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments.” The document can be downloaded at the following link:http://www.oehha.ca.gov/air/hot_spots/HRSguide.html.

Vector Environmental: Emissions from Offroad Mobile Sources and Portable Equipment Required for the Construction of Wells. 2015. Criteria pollutant emission data by activity, phase and task for years 2012-2029.

Vector Environmental: MS Excel spreadsheet entitled: “DRL_EMISSIONS.xlsx”.

Appendix A –
Equipment and Emissions for Drilling a 13,000’ Well

2017 Emissions from a 13,000' Well
Construction Activity: A.1 Land Preparation

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Water Truck	1	7	8.48	400	2.72
Loader	1	4	2.5	100	.29
35 Yard Dump Truck	1	2	1.00	400	.09
Grader	1	4	2.5	175	.68
Skip & Scrap (Backhoe)	1	1	1.0	100	.03
Big Scrapper	1	2	2.5	362	.41
Dozer (D9R)	1	1	1.0	255	.08
Low Bed Truck/Trailer	1	2	.5	400	.05
Dump Truck 10 Wheels	1	1	.5	400	.02
Backhoe	1	2	.54	100	.03
Loader	1	3	2.5	100	.22
Loader	1	2	1.0	100	.06
Escavator (Backoe/tracks)	1	1	1.0	163	.02
Dozer (D8T)	1	1	1.0	255	.08
End Dump Truck & Trailer	1	1	.50	400	.02
Grader	1.0	1.0	.50	175	.03

2017 Emissions from a 13,000' Well
Construction Activity: B.1 Drilling Survey

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Rig	1	1	12	100	0.58
Cement Truck	1	1	12	400	0.55

2017 Emissions from a 13,000' Well
Construction Activity: C.1 Well Drilling

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Crane	1	2	8	230	0.69
Port Light Stands	5	44	12	20	19.06
Portable Gen. Hydraulic Power	1	44	22	80	27.45
Portable Gen. DSM/Trailers	2	44	24	100	74.85
Portable Gen. Mud Separator	1	43	22	420	45.51
Diesel Electric - Rotary	1	43	22	158	57.08
Diesel Electric Hoist	1	43	22	1094	182.62
Diesel Electric Hoist	1	43	22	962	160.58
Diesel Electric Hoist	1	43	22	1898	316.83

2017 Emissions from a 13,000' Well
Construction Activity: D.1 Well Completion

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Accumulator Generator	1	17	24	100	12.76
Filter Skid (Pump)	1	2	3	90	0.19
Acid Pump #1 (Hydraulic Oil Pump)	1	1	22	175	0.72
Acid Pump #2 (Acid Fluid Pumping)	1	1	22	765	1.45
Generator for Doghouse for WO Rig	1	17	24	70	8.93
3 Light Plants for WO Rig	3	17	12	20	3.90
Diesel Engine for COROD or Other	1	1	22	450	1.49
Portable Den. Mud Separator	1	17	22	420	15.87
Diesel Electric - Rotary	1	17	22	144	18.15
Diesel Electric Hoist and Pump	1	17	22	996	58.00
Diesel Electric Hoist and Pump	1	17	22	981	57.12
Diesel Electric Hoist and Pump	1	17	22	1145	66.67

2017 Emissions from a 13,000’ Well
Construction Activity: E.1 Well Flowline

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Side Boom D4/Crawler	1	3	10	520	0.79
Backhoe	1	3	10	95	0.84
Pipe Fitting or Welders	1	3	10	40	0.43
Hydrotest Pump	1	1	1	20	0.01
Forklift	1	3	10	125	0.49
Other Equipment/Bending Machine	1	3	10	80	1.04

2017 Emissions from a 13,000’ Well
Construction Activity: F.1 Pump Unit

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Power Generator	1	2	8	10	0.06
Backhoe	1	2	4	80	0.19
Welder	1	2	8	25	0.14

2017 Emissions from a 13,000’ Well
Construction Activity: G.1 Electrical

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Line Truck	1	4	10	250	1.50
Bucket Truck	1	4	10	250	1.50
Electrical Service Truck	1	4	1	300	0.14
Power Generators	1	4	1	10	0.01
Back-Hoe	1	1	10	650	0.74

Appendix B – Modeling Files

(Files on CD at County Office - Available for Viewing by Appointment)

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Appendix C – HARP2 Output

(Files on CD at County Office -
Available for Viewing by Appointment)

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Health Risk Assessment Guidelines Review

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Environmental Compliance Solutions, Inc.

MEMORANDOM

To: Western States Petroleum Association (WSPA)

From: Erin Sheehy – ECS

Date: April 15, 2020

Re: Health Risk Assessment Guideline Changes Since 2015

In 2015, Environmental Compliance Solutions, Inc. (ECS) assisted with the Environmental Impact Report for *Revisions to the Kern County Zoning Ordinance – 2015C, focused on Oil and Gas Local Permitting*. We completed the Health Risk Assessment (HRA) technical appendix which included numerous HRAs prepared to calculate potential air quality health risks from various hypothetical well drilling scenarios throughout the county.

California's HRA procedures require the use of both the United States Environmental Protection Agency's (EPA's) AERMOD model and the California Air Resources Board's (CARB's) Hotspots Analysis and Reporting Program (HARP2) model. California's Office of Health Hazard Assessment (OEHHA) provides toxicity levels for all hazardous air pollutants to be modeled.

CARB made significant modifications to the HARP2 model in March 2015 and that version of the model was used for all calculations completed for the abovementioned CEQA document.

Between 2015 and now, minor updates to AERMOD and HARP2 have been released. Specific changes to each model are outlined in Attachment A. OEHHA has not modified or revised the toxicity factors for any of the chemicals (diesel particulate matter, benzene, cyclohexane, ethylbenzene, n-hexane, toluene, xylenes, 1,2,4 trimethylbenzene and hydrogen sulfide) used in the 2015 well drilling study.

Conclusion

As is detailed in Attachment A, none of the changes or updates from the three regulatory agencies are believed to potentially alter the conclusions of the 2015 Kern County study.

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Attachment A
Summary of Specific Modeling Updates Since 2015

EPA's AERMOD Updates

Subsequent to the Kern County analysis, EPA released three updated versions (16286, 18086, and 19191) of AERMOD. Specific revisions are summarized below.

v.16286: EPA updated a source release height input. This could potentially change previous results in a small, negligible way.

v.18086: This model version changed the wind downwash algorithm, but downwash was not needed as part of the previous study; therefore, no change to results is expected.

v.19191: Key updates included incorporating background concentrations into model results, particle deposition, low wind speed options and buoyant line sources. This would not be expected to change previous results.

CARB's HARP2 Updates

CARB has updated HARP2 nine times since 2015. Specific version changes are outlined below. No change was identified that might alter the conclusions of the 2015 HRAs in any substantive way.

v.16057: This version involved corrections to repair problems that were causing the model to fail; and thus would not affect previously-run analyses. Additionally, multipathway options and reporting presentation methods were updated that would not be expected to change previous results.

v.16088: This version fixed issues with a non-default model that was not used in the 2015 studies. New health table (risk factors) processors were also incorporated in this version for toxic compounds that were not part of the Kern County 2015 HRAs.

v.16217: Changes in this release affected operational aspects of the model and were not related to risk calculations.

v.17023: This version updated the computer program's functionality and efficiency of use (i.e., HRACalc processor and data importer upgrades). These were not areas that affected the Kern study.

v.17052: This release improved model functionality and updated information for some substances not part of the study.

v.17320: This update included additional model functionality, added specific air district health data tables and updated the AERMOD model. These changes would not affect the Kern study.

v.18159: This update included an updated AERMOD module, corrected importing and exporting information, and updated the health table. The updated health table did not make changes to any of the hazardous air pollutants analyzed in the previous study.

v.19044: This update improved functionality, updated the health table and updated the HRACalc processor. These changes would not be expected to affect the results of the Kern study.

v.19121: This update changed the building downwash algorithm. Building downwash was not used in the Kern study and thus would not alter the results.

Model Change Bulletin (MCB) 14 – AERMOD version 19191 changes by change type.

Listed with each change are the affected pollutants and source types:

Bug Fixes

Item	Modification	Pollutants	Source Types
1	**BACKGROUND Concentrations output units** Modified subroutine SUMBACK to convert background concentrations to the model output units requested via the EMISUNIT or CONCUNIT keywords. Background concentrations are converted internally in AERMOD to $\mu g/m^3$ but were not being converted to the requested output units when model outputs were not $\mu g/m^3$. Background concentrations are converted to the requested model output units by dividing EMIFAC(1) by 1.0×10^6 (the default conversion of grams to mg) in SUMBACK.	All	All
2	**BACKGROUND Concentrations and deposition** Modified subroutine SUMBACK to not include background concentrations with deposition outputs. Previously, if background concentrations were in an AERMOD run with deposition outputs, background concentrations were added to deposition fluxes.	All	All
3	**Wet particle deposition and Method_2 particle deposition** Modified subroutine SCAVRAT to calculate the scavenging ratio when using Method_2 particle deposition based on a parameterization of the washout ratio from Wesely 2002. Washout ratio is calculated based on the fine mass fraction, and an assumed diameter of 6 microns for the coarse mode. The washout ratio is used to calculate the collision efficiency which is then used to calculate the scavenging ratio. Previously, AERMOD used particle density and settling velocity for the fine particle to calculate wet deposition parameters when using Method 1 or 2 for particle deposition. These were inconsistent with the Method 2 inputs in that density is not an input for Method 2 and Method 2 dry deposition assumes a settling velocity of 0 m/s for the fine particle mode.	Particulates	All
4	**Buoyant Line Source Minimum Release Height and Minimum Wind Speed** A minimum release height of 2.0 meters is imposed. A buoyant line source release height of 0.0 meters caused AERMOD to run very slowly and produce 0.0 ug/m3 for all	All	Buoyant Line

	hours and receptors. A minimum reference height wind speed of 1.0 m/s is imposed. This value is consistent with the meteorology that was produced with the CRSTER meteorological processor, the met processor for the Buoyant Line and Point (BLP) model.		
5	**MODELOPT Number 6** Previously, the AERMOD.out summary file lists two No. 6 user-specified options when user selects non-DFAULT and URBANOPT. One of the two messages incorrectly indicates a NO2 conversion is applied when non-NO2 POLLUTID used. An if statement was added for NO2 processing in inpsum.f to remove the duplicated message.	All	All
6	**DFAULT with ADJ_Ustar** Previously, a W402 warning message was returned in the AERMOD.out summary file when the DFAULT MODELOPT was used without use of the AERMET ADJ_U*. The block of code responsible for the incorrect warning message was eliminated in PFLCNV subroutine of metext.f.	All	All
7	**ERRMSG(18)** ERRMSG(18) was defined three times in modules.f, using ERRHDL numbers 133, 137, and 138, which resulted in some compilers (g95) not functioning properly. The modules.f file was reorganized sequentially and ERRMSG(18) usage of ERRHDL 137 and 138 was removed. ERRHDL 137 and 138 were replaced with ERRMSG 204 in the coset.f.	All	All
8	**LOW_WIND Undefined ERROR Message** Previously, an undefined ERROR message and "ELWD" error code was returned in the AERMOD.out summary file when the LOW_WIND MODELOPT was used without the ALPHA MODELOPT. The ERROR message code was modified to "E133" in coset.f.	All	All
9	**ELEVUNIT** Previously, the optional ELEVUNIT keyword to convert elevation units from feet to meters was not applied to LINE or BUOYLINE sources. The SOLOCA subroutine in soset.f was modified to apply the feet to meters conversion used for other source types to LINE and BUOYLINE sources.	All	Line and Buoyant Line

Enhancements

Item	Modification	Pollutants	Source Types
1	**ARM2 Enabled with BETA RLINE and ALPHA RLINEXT Source Types**	All	Rline and Rlinext

	ARM2 was extended for application to sources and source groups that include the BETA RLINE and ALPHA RLINEXT line sources.		
2	**EVENT Processing Enabled with BETA RLINE and ALPHA RLINEXT Source Types** EVENT processing was extended for application to sources and source groups that include RLINE and RLINEXT line sources.	All	Rline and Rlinext
3	**Urban Stability Enabled with BETA RLINE and ALPHA RLINEXT Source Types** The URBAN option was extended for application to sources and source groups that include RLINE and RLINEXT line sources.	All	Rline and Rlinext
4	**Buoyant Line Source Urban Stability** Previously, AERMOD treated a buoyant line source in an urban environment as a source in a rural environment, as is done in the Buoyant Line and Point (BLP) model. The capability to process a buoyant line source in an urban environment was added as an ALPHA option. The surface roughness (SFCZ0), Monin-Obukhov length (OBULEN), and mixing height (ZI) are adjusted for an urban environment and a new value of the Pasquill-Gifford (P-G) stability category (KST) is computed using the subroutine LTOPG.	All	Buoyant Line

Formulation updates – Regulatory

None

Formulation updates – BETA

1	**RLINE Source Type** The RLINE source type was added to model roadways, or similar line-type releases, which uses the dispersion calculations from the R-LINE model (version 1.2) and requires the BETA and FLAT model options. The RLINE source type has identical inputs to the LINE source type R-LINE model: current version 1.2, last updated November 2013 (https://www.cmascenter.org/r-line).	All	Rline

Formulation updates – ALPHA

1	**Enhanced Building Downwash Options** Options to examine the effects of enhanced building downwash algorithms for point sources was added. The user can selectively apply one or more of these options in the AERMOD input control file. Two new keywords are added to the CO pathway: ORD_DWNW and AWMADWNW. Each of these keywords has several parameters that control downwash processing. For ORD_DWNW, the parameters are: ORDUEFF to control the height at which an effective wind speed is calculated for main plume concentrations; ORDTURB to control an adjustment for the non-dimensional vertical turbulence intensity, wiz0, from 0.6 to 0.7; and ORDCAV to shift the point at which the vertical and lateral dispersion coefficients begin to grow with downwind distance from the lee edge of the building to the end of the cavity. Parameters available for the AWMADWNW keyword are: AWMAUEFF to control the height at which an effective wind speed is calculated for main plume concentrations; AWMAUTURB to specify new lower and upper bounds for calculating the effective parameters ueff, sweff, sveff, and tgeff; and STREAMLINE (or STREAMLINED) to perform downwash for a streamlined building such as a cooling tower. Any combination of parameters is allowed **EXCEPT** ORDUEFF and AWMAUEFF cannot both be specified in the same model run. In addition, STREAMLINE (or STREAMLINED) requires the AWMAUTURB option to also be specified. If any of these keywords and parameters are used, the ALPHA option must be specified on the MODELOPT record. An optional debug file is available for the options associated with the AWMADWNW keyword by specifying AWMADW on the DEBUGOPT keyword. If none of these options are applied, the standard AERMOD building downwash algorithms will be used.	All	Point
2	**RLINEXT Source Type** The RLINEXT source type was added to model roadways, or similar line-type releases, using the dispersion calculations from the R-LINE model (version 1.2) and requires the ALPHA and FLAT model options. The RLINEXT source has inputs and capabilities identical to the R-LINE model. The RLINEXT source has capability to model depressed roadways and roadside barriers; the RLINE source does not have these capabilities. R-LINE model: current version 1.2, last updated November 2013 (https://www.cmascenter.org/r-line).	All	Rlinext

3	**Method 2 particle deposition and gas deposition ALPHA Option** Gas deposition and method 2 particle deposition were switched from non-DEFAULT to ALPHA options. While the two deposition options were previously non-DEFAULT, there has been little evaluation of their use in AERMOD. It was decided to make these two options ALPHA options while the deposition algorithms undergo evaluation. Note that METHOD 1 particle deposition is still allowed with the DFAULT option as it is based on a method from a previous model, the Acid Deposition and Oxidant model (ADOM)	Gaseous and particulates using Method 2	All

Model Change Bulletin (MCB) 13 – AERMOD version 18081 changes by change type.

Listed with each change are the affected pollutants and source types:

Bug Fixes

Item	Modification	Pollutants	Source Types
1	**PRIME Downwash Receptor Bug** In the subroutine SZSFCLPR in prime.f, the calculation of the surface layer dispersion term is different for stable and unstable conditions. For unstable conditions, in 15181 the term was calculated if the receptor height was less than 1/10 of the mixing height. Otherwise, the surface layer dispersion term was set to 0.0 in unstable conditions. In 16216r, the conditional statement was modified to calculate the term if the release was considered a surface release, regardless of the receptor height. Thus, the surface layer dispersion term is applied in 16216r under unstable conditions to all receptors if defined as a surface release which is determined differently under different conditions. Code was reverted back to 15181.	All	POINT
2	**Urban SO2 Half-life for Non-Default Applications** AERMOD includes a decay coefficient for URBAN SO2 sources. This decay will automatically apply if the DFAULT option is specified, but was not applied for Non-DFAULT applications of AERMOD (i.e., when DFAULT option keyword was omitted). The 4-hour half-life is now applied to SO2 urban sources regardless of whether the DFAULT option is specified or not and a user-defined value is not specified. The default decay coefficient is 4-hours if a user-defined value is not specified. Subroutines BL_CALC in calc1.f and DECAY in calc2.f were updated to apply the default (or user-defined) decay coefficient to urban SO2 sources for non-default applications.	SO2	All
3	**Annual POSTFILEs** For multi-year runs, when outputting ANNUAL POSTFILEs, AERMOD would output each year's annual concentration at each receptor with year numbers 1,2, etc. Following all of the individual years' concentrations, AERMOD would output the multi-year average at each receptor and labeled the row with the final year number. Reporting individual year's concentrations was introduced in 15181. Prior to 15181, the POSTFILE would output the multi-year average, not individual years. In this release, the POSTFILE will have the individual years, but not the multi-year average. The multi-year	All	All

	average can still be obtained from a PLOTFILE. In aermod.f, the condition of call to subroutine PSTANN was modified to avoid writing period average to annual POSTFILE.		
4	**Buoyant Line Source Parameters Summary** Summary table of buoyant line source parameters was not included in the AERMOD.OUT file along with the summaries for other source types. Summary table was added.	All	BUOYLINE
5	**AERMOD Seasonal Assignment** AERMOD was using the wrong seasonal assignment for calculation of cuticle resistance for ozone (Rcox) for winter and snow precipitation in subroutine VDP in calc1.f. Conditional statement was corrected to reference seasonal code 4 (winter with snow) rather than 5.	All	All
6	**ARM2 Error/Warning Messages for Range Checks** Corrections were made to the range checks for user-defined ARM2 limits and Error and Warning messages were updated accordingly.	NO2	All
7	**Background Sectors Output** AERMOD was printing the SECT1 values for both SECT1 and SECT2 for: SEASON, MONTH, HROFDY, HRDOW, HRDOW7, SHRDOW, SHRDOW7, MHRDOW, MHRDOW7 (functioning correctly for SEASHR). SECT2 values were correctly used in the model, but were printed incorrectly in the output list file Also, AERMOD was not writing any values for WSPEED. Reporting errors were corrected in this release.	All	All
8	**Apply Minimum Wind Speed** The minimum wind speed was applied to vector winds in calc1.f and iblval.f by taking the max of the calculated effective wind speed and minimum wind set as a lower limit (either a default value or user-defined value that is entered with the ALPHA and LOW_WIND keywords).	All	All
9	**Meteorological Surface File Check** If the surface meteorological file existed, but was empty, AERMOD would enter an infinite error loop. This cause AERMOD to write to the error file until the local disk was full. meset.f was modified to check to see if the file was empty on first read and issue the correct warning if so.	All	All

Enhancements

Item	Modification	Pollutants	Source Types
1	**ARM2 Enabled with Buoyant Line Source** ARM2 was extended for application to buoyant line sources and source groups that include buoyant line sources.	NO2	BUOYLINE

2	**Addition of ALPHA Option Flag** Similar to the BETA option flag, an ALPHA option flag was added to distinguish options that are considered research/experimental options (ALPHA) from those that have been vetted within the scientific community that are under consideration for promulgation as regulatory options (BETA).	All	All
3	**Command-line Arguments** Capability added for user to specify control filename (.inp) and standard output filename (.out) on the command-line when AERMOD is executed. User can include 0, 1, or 2 arguments. If no arguments are included, AERMOD will assume the default names (aermod.inp and aermod.out). When included, the first argument must be the control filename, and the second argument must be the output filename. If only the control filename is provided, AERMOD will use the path and base of the control filename (excluding extension) as the path and base filename for the output file and append ".out" to the end of the filename. Filenames can include the absolute path or relative path from the working directory.	All	All
4	**Removal of LOWWIND1, LOWWIND2, LOWWIND3** Individual BETA options LOWWIND1, LOWWIND2, LOWWIND3 were removed and replaced with LOW_WIND ALPHA option that enables user to specify different values for minimum wind speed, sigma-v, and maximum meander factor (see LOW-WIND Alpha Option in the Enhancements section).	All	All
5	**LOW_WIND ALPHA Option** A new ALPHA option LOW_WIND which enables the user to enter user-defined values for minimum wind speed, sigma-v, and maximum meander factor in lieu of LOWWIND1, LOWWIND2, and LOWWIND3.	All	All
6	**ARM Removed** The original Ambient Ratio Method (ARM), which was replaced with ARM2, was still functional in AERMOD 16216r and could be specified when the DFAULT keyword was also specified. ARM has been removed from AERMOD. Equivalent functionality can be obtained by setting the maximum and minimum ambient ratio to the desired value using the ARM2 options.	NO2	All
7	**Rename Functions ERF and ERFC** Absoft and gfortran compilers issued warnings that the user-defined functions ERF and ERFC in prime.f were named the same as two intrinsic functions. User-defined functions were renamed FNERF and FNERFC to avoid a potential name conflict. Call statements were updated to reference new function names.	All	All
8	**Uninitialized Variables** Initialized variables identified by gfortran compiler as uninitialized. Exceptions are the allocated arrays. All variables that were initialized are set = 0.0D0 (all are double precision). All variables identified were found to be set somewhere in the code either as the	All	All

	value of another variable or by formula, so initialization has no effect. Allocatable arrays were already initialized in code at some point after allocation.		

Formulation updates

None

Model Change Bulletin (MCB) 12 - AERMOD version 16216 changes by change type.

Listed with each change are the affected pollutants and source types:

BUG FIXES

Item	Modification	Pollutants	Source Types
1	Modified subroutine HRLOOP to use .LE. instead of .LT. in comparing FULLDATE vs. IEDATE.	All	All
2	Modified subroutine ALLSETUP to increment the array dimensions associated with AREA source types by 1 to accommodate more complex AREAPOLY sources.	All	AREA
3	Modified subroutine PRESET to account for name changes in the beta low wind options.	All	All
4	Modified subroutine SBLRIS to avoid potential runtime errors in calculating plume rise under stable conditions if (TERMB*TERMC+1-TERMD) .LE. 0.0	All	POINT
5	Modified subroutine SETSRC to initialize SURFAC = .T. for sources with release heights less than 0.1 times the mixing height (ZI).	All	POINT
6	Modified subroutine CENTROID to set SURFAC = .F. for sources with release heights greater than or equal to the mixing height (ZI).	All	POINT
7	Added code to define a receptor exclusion zone in which receptors within the maximum extents of a buoyant line source are omitted from calculations	All	BUOYLINE
8	An individual line in a buoyant line source can be included in a SRCGROUP	All	All
9	The hourly emissions file for a buoyant line source now requires a buoyancy flux parameter for each line of a buoyant line source	All	All
10	Included buoyant line sources in event processing	All	BUOYLINE

ENHANCEMENTS

Item	Modification	Pollutants	Source Types
1	Subroutine PRESET was modified to account for BLP options.	All	All
2	Replaced the previous PVMRM option with the PVMRM2 option, retaining PVMRM as the option name.	NO2	All
3	Removed the requirement for specifying the BETA option for application of the PVMRM, OLM, and ARM2 options for NO2.	NO2	All
4	Modified subroutine SOLOCA to remove the BETA/Non-default status of POINTCAP and/or POINTHOR sources.	All	POINTCAP & POINTHOR
5	Modified subroutine MEOPEN to remove BETA/Non-default status of MMIF meteorological data	All	All
6	Modified subroutines MEOPEN and PFLCNV to identify whether measured turbulence parameters (i.e., Sigma-Theta	All	All

	and/or Sigma-W) are included in the PROFFILE input file. This information is used to determine whether an application utilizing the ADJ_U* option in AERMET is considered to be "regulatory" or non-DFAULT.		

MISCELLANEOUS

Item	Modification	Pollutants	Source Types
1	The format of the MODOPS array included in the header records of AERMOD output files has been slightly modified.	All	All

Version History **19121 - May 1, 2019** - Fixed an error associated with contouring risk results using offset coordinates. - Reversed a fix made when importing building heights from a database. Staff determined the fix made in version 19044 was not an error in HARP but instead in the user data that was supplied when staff first diagnosed the error. **19044 - February 13, 2019** - Fixed an issue with variable emissions rate keyword options SHRDOW, SHRDOW7, MHRDOW, and MHRDOW7. The error caused the air dispersion analysis to fail. - Fixed an error with building height conversion when importing from a database. - Fixed an issue with exporting health database information to a CSV file from the View Health Table window. - AERMOD v18081 has been replaced with an updated 64-bit copy from EPA's SCRAM website. The version previously packaged with HARP had an issue with creating large file sizes for the detailed error listing file. - If the urban option is selected, HARP now checks if the urban parameter is completed. - HARP now saves the output file for second air dispersion run for the acute analysis when variable emission rates are used in the air dispersion analysis. - The latest health database (**v18232**) is now included in the ADMRT installation package. - ADMRT includes the new HRACalc processor (dated 19044). The HRACalc is the processor that calculates risk. An issue was identified with the egg pathway. The risk from the egg pathway errored if the egg parameters were not entered properly. **18159 - June 8, 2018** - AERMOD v18081 and AERMAP v18081 are now included with HARP. The interface has been adjusted to reflect changes in AERMOD v18081. For compatibility purposes, HARP is setup to use the 32-bit version of AERMOD by default. User may replace it with the 64-bit version of AERMOD if they know their computer is compatible. - Fixed an issue with exporting data from the health database. - Fixed an issue with importing emission data. - Fixed an issue with creating KML files using air dispersion data processed outside of HARP. - New option to remove pollutants without health values. This feature is found in the emission inventory tab under the Options menu option. - The latest health database (**v18121**) is now included in the ADMRT installation package. **17320 - November 16, 2017** - Fixed bug preventing HARP from running in screening mode. - AERMOD v16216r has been included in the AMDRT package. Interface has been adjusted to reflect changes in AERMOD v16216r. - Added an option to select South Coast Air Quality Management District (AQMD) mandatory minimum pathways. - Added a Bay Area AQMD health table option. This option can be found under File\Settings. Please contact Bay Area AQMD for information on the use of the health table. **17052 - February 21, 2017** - Fixed an issue with import emission data via a HARP database. - Fixed issues with displaying risk options with some risk combinations. - Project loading and importing speeds have increased. - File overwrite warning was added to help prevent users from overwriting existing risk results. - The new Reference Exposure Levels for carbonyl sulfide (463-58-1) were added to the health database. For more information, please visit http://oehha.ca.gov/air/hot_spots/. - The new unit risk factor for perchloroethylene (127-18-4) was updated in the health database. The unit risk factor is for prioritization calculations and is not used in cancer risk calculations. For more information, please visit http://oehha.ca.gov/air/hot_spots/. **17023 - January 23, 2017** - Fixed an issue with selecting a user-defined health database. - Fixed an issue with the chronic spatial averaging feature. The wrong receptor coordinates would be populated when using the lookup feature. - Fixed an issue with the spatial averaging option. When the air dispersion analysis is reran, it may use a variable emission schedule meant for the acute analysis. - Fixed an issue with selecting inhalation only pathway for a worker scenario. - Fixed an issue with calm hour processing when post processing refined worker concentrations. - Fixed an issue with handling non-numeric concentrations in the plot file. - Fixed an issue with handling pollutants not contained in the health database. - The worker adjustment factor will be automatically unchecked if refined worker results are checked. - General text changes. - Users can now see when the AERMOD input file was last saved. - Added progress bar for refined acute calculations. - Added ability view, search, and export health database. - Added button to normalize emission rates for HROFDY, HRDOW,& HRDOW7 options. - ADMRT includes the new HRACalc processor (**dated 17023**). The HRACalc is the processor that calculates risk. - Added additional information to the risk result files - The "Scenario" column includes information about which pathways were ran; if FAH option was applied; and if user-defined values were supplied. - The title header includes the file path and name of the input file. ***There are no changes to the risk equations or HRA input file*** ****16217 - August 4, 2016** -** Fixed an issue with resizing the application screen. The navigation panel will now remain the same width when the application is resized. - Fixed an issue with reloading AERMAP output files. - Fixed an issue with exporting receptor location in the Risk Contour window. - Fixed an issue with offset coordinates in the contour window. Offset XY coordinates were transposed. - Fixed an issue with the report by source feature not resetting completely after the report is created. - Fixed an issue with importing sources with special characters in the name or description. Quotation marks are require around data with special characters. - Fixed an issue with exporting spatially averaged chronic results to a KML file. The kml feature did not use the updated subroutine released in version **16057**. - Fixed an issue with displaying the correct averaging results for the non-cancer chronic spatial averaging option. - New option to copy the project to another directory. - The risk results filename and path are now displayed in the View Risk Result and Spatial Averaging screens. - The default filename for risk calculations can be change in spatial averaging. - Column headers were added to exported spatial averaging results. - To view the spatially average cancer risk, you now must click "View\Get Average Risk from All Receptors" from the menu options in Spatial Averaging screens. - General text changes. - Default NETIDs have been added to the "Pathway\Spatial Avg GLCs" window for calculating spatially average concentrations for pathway receptors. ****16088 - March 28, 2016** -** Fixed issue with loading of spatial averaging offset coordinates. - Fixed issue with creating the AERMOD input when non default options are selected in some cases. - The version number on some files were not updated in the last release. - Added beta option in the control pathway of the air dispersion setup. This option turns on the beta option if the ADJ_U* option in AERMET was used. Selecting this option is required by some districts when using their meteorological files. - ADMRT includes the new HRACalc processor (**dated 16088**). The HRACalc is the processor that calculates risk. The version number of the HRA input file may be misread. The HRA input file may have to be recreated on older projects. - Health table as been updated (**dated 16088**). The new Reference Exposure Levels for toluene diisocyanate isomers and methylene diphenyl diisocyanate recently adopted by the Office of Environmental Health Hazard Assessment are included in the new health database. For more information, please visit http://oehha.ca.gov/air/hot_spots/. ****16057 - February 26, 2016** -** Fixed reference error with area sources losing the initial vertical dimension (SZINIT) parameter when the source is revisited. - Fixed issue with LOWWIND parameter being automatically selected when a project is reopened. - Fixed reference error for the specified end time period of the meteorological file. This occurs when a project is reopened. - Fixed issue with the automated second air dipsersion run for the acute analysis. - Fixed issue with using refined dispersion results for cancer analysis. - Fixed issue with source origins not displaying in the KML output under the air dispersion analysis section. - Fixed issue with selecting user-defined site parameters the first time in the risk analysis section. - Fixed issue with site parameters when water parameters where set to zero for beef, dairy, pigs, chickens, or egg. - Fixed issue with settings window not closing out. - AERMAP will error if line sources are supplied. As a workaround, HARP will enter the starting XY coordinate of the line source and enter it as a point source in AERMAP. Please manually enter the elevations for line sources if better data are available. - Added check to see the BPIP file exists when setting up the air dispersion input file. **- AERMOD 15181** has been included in the AMDRT package - Calculate GLC button has been moved from the menu options so it is more visible. - Added scrollbars to screen for systems with small display sizes. - New batch feature to calculate risk by source. Individual risk files are created for each source and a source summary file. Note: It is recommended that this feature is ran in combination with selecting a single receptor option as the files will be large. Also, summing risk by individual source will not necessarily added up to the same total when comparing the sources as a whole. This is more prevalent when calculating risk using a derived scenario. - New option to calculate risk for a single receptor. - New option to identify multipathway pollutants in the Calculate/Import GLC section. - More information about the selected risk scenario and parameters were added to the HRA output log file. - KML feature: - Option to export receptors without labels. - No restrictions on zooming in. Receptors will not disappear when zoomed in close. - UTM zone check on export. Resolve issues with imported AERMOD runs. - Like receptors are now grouped together in separate folders. - Risk data is automatically sorted in descending order. - General text changes. - ADMRT includes the new HRACalc processor (**dated 16057**). The HRACalc is the processor that calculates risk. It was reconfigured for batch processing for calculating risk by source. - Health table as been updated (**dated 16057**). 27 pollutants health values have been removed from the health database. OEHHA has determined these values do not apply to the Hot Spots Program. Most of the pollutants are pesticides. The health values have been removed for the following pollutants: PolID Pollutant 78875 1,2-Dichloropropane 122667 1,2-Diphenylhydrazine {Hydrazobenzene} 542756 1,3-Dichloropropene 53963 2-Acetylaminofluorene 92671 4-Aminobiphenyl 61825 Amitrole 57578 beta-Propiolactone 2425061 Captafol 133062 Captan 57749 Chlordane 510156 Chlorobenzilate 107302 Chloromethyl methyl ether (technical grade) 1066 Coke oven emissions 72559 Dichlorodiphenyldichloroethylene {DDE} 62737 Dichlorovos {DDVP} 79447 Dimethyl carbamoyl chloride 151564 Ethyleneimine {Aziridine} 76448 Heptachlor 67721 Hexachloroethane 139139 Nitrilotriacetic acid 1116547 N-Nitrosodiethanolamine 684935 N-Nitroso-N-methylurea 90040 o-Anisidine 95534 o-Toluidine 50555 Reserpine 62566 Thiourea 8001352 Toxaphene ****15197 - July 16, 2015**** - Fixed an issue when exporting chronic 8-hour risk results to plot files. - Fixed an issue when opening a project. Previous risk results for cancer, chronic, and acute would not load correctly if the files were a mixture of new and old runs. - Column headers were added to CSV files when exporting risk results. - ADMRT includes the new HRACalc processor (**dated 15197**). The HRACalc is the processor that calculates risk. Changes to the HRACalc process (**dated 15197**) - Fixed risk breakdown column order associated with the new cancer report risk report by receptor. Several risk results did not match up with the column names. ****15180 - June 29, 2015**** - Fixed pathway receptor reference issue under some scenarios when creating the AERMOD input file. - Fixed flag pole parameter issue for polar receptors when creating the AERMOD input file. - Fixed xy coordinate reference issue for census receptors when terrain options are not used. - Fixed issue when importing building boundaries from a HARP database. Coordinates where flipped producing a mirror image of the building boundary. - Added check to see if AERMAP was ran when terrian options are selected. - Added MAXHI column in the kml file output for noncancer health impacts. - Added the ability to clear database from the project. - Flat terrain group box will now grey out when default modeling options are selected. - New option to reset the emission multiplier for all sources. - New option to turn on emissions for a group of sources. The multipliers will be set to one for selected sources and the rest will be set to zero. This feature can be used for determing the risk from a single or a selected group of sources. - Fixed issue with KML risk contouring. Some testing parameters were enabled in the prior release. Please note this feature can only contour using a single square Cartesian grid. This feature will be improved over time. - New options for KML risk contouring. Users now have the ability to change contour color, enter offset coordinates, change zone information, and add another layer to include receptor locations with risk. - The risk results menu options has changed to work with the new HRACalc (**dated 15180**) processor. Previously, HARP automatically loaded a file containing the risk breakdown by pollutant and receptor. However, users running large number of sources (in the hundreds), receptors (in the thousands), and pollutants can easily exceed the memory limits of the program. The file size could exceed to over 500MB. To address this, HARP is now setup to outputs both a file containing the risk breakdown by pollutant and receptors and a file containing the total risk by receptors. HARP now only automatically loads the file containing the total risk by receptor. The larger "breakdown" file must be opened manually from the risk result menu options. Please note HARP restricts the user from opening "breakdown" files that exceed 100MB. These large "breakdown" files may be opened using a database program. Changes to the HRACalc processor (dated 15180) - Fixed exposure duration distribution error when using some exposure duration ranges under a Tier 2 scenario. - Fixed memory limit error when running a large number of sources, receptors, and pollutants. The program is now setup to outputs both a file containing the risk breakdown by pollutant and receptors and a file contain the total risk by receptors. ****15076 - March 17, 2015**** - The feature to check for updates has been adjusted to allow the RAST and the ADMRT to be independently updated. - The new Reference Exposure Levels for benzene that were part of the last installation package were not updated properly. The setup and deployment package did not update all the files. The previous version of HARP should be uninstalled first and the PRStartup.ini should be deleted from the HARP2 folder before installing the latest version. - The setup and deployment package has been fixed to resolve issue with updating the software. - A potential issue has been fixed when importing emission inventory data with inconsistent pollutant names. ****15071 - March 12, 2015**** - It was discovered the new Reference Exposure Levels for benzene were inadvertently left out of the initial release. In addition, the update feature that would typically handle health value updates was pointing to the wrong server in the Risk Assessment Standalone Tool and the Air Dispersion Modeling and Risk Tool. ****15065 - March 6, 2015** - Initial release**

Nov 4, 2019: [OEHHA Acute, 8-hour and Chronic Reference Exposure Level (REL) Summary]

Summary table of all OEHHA acute, 8-hr and chronic Reference Exposure Levels (chRELs) as of November 2019. Documentation for these values is available in the Air Toxics Hot Spots Program Guidance...

Nov 1, 2019: [Extension of the Public Comment Period for the Draft Hot Spots Cancer Inhalation Unit Risk Factor for p Chloro-α,α,α-trifluorotoluene (p-chlorobenzotrifluoride, PCBTF)]

OEHHA has received a request from the American Coatings Association to extend the public comment period. This notice extends the comment period to December 17, 2019.

Oct 18, 2019: [Public Comment Period and Workshops on the Draft Hot Spots Cancer Inhalation Unit Risk Factors for p Chloro-α,α,α-trifluorotoluene (p-chlorobenzotrifluoride, PCBTF)]

The Office of Environmental Health Hazard Assessment (OEHHA) is releasing a document for public review that summarizes the carcinogenicity and derivation of a cancer inhalation unit risk factor (IUR...

Sep 6, 2019: [Notice of Adoption of Reference Exposure Levels for Hexamethylene Diisocyanate (Monomer and Polydiisocyanates)]

RELs are airborne concentrations of a chemical that are not anticipated to result in adverse noncancer health effects for specified exposure durations in the general population, including sensitive...

Sep 4, 2019: [Cobalt and Cobalt Compounds Cancer Inhalation Unit Risk Factor (IUR) Document - Scientific Review Panel on Toxic Air Contaminants (SRP) Review Draft]

IURs are used to estimate lifetime cancer risks associated with inhalation exposure to a carcinogen.

May 31, 2019: [Draft Document Summarizing the Toxicity and Derivation of Reference Exposure Levels (RELs) for Toluene]

The Office of Environmental Health Hazard Assessment (OEHHA) is releasing a draft document summarizing the toxicity and derivation of Reference Exposure Levels (RELs) for Toluene. This document will...

Apr 10, 2019: [Extension of the Public Comment Period for the Proposed Cancer Inhalation Unit Risk Factors for Cobalt and Cobalt Compounds]

The Office of Environmental Health Hazard Assessment (OEHHA) is releasing a document for public review that summarizes the carcinogenicity and derivation of cancer inhalation unit risk factors (IURs...

Mar 8, 2019: [Public Comment Period and Workshops on the Draft Hot Spots Cancer Inhalation Unit Risk Factors for Cobalt and Cobalt Compounds]

The Office of Environmental Health Hazard Assessment (OEHHA) is releasing a document for public review that summarizes the carcinogenicity and derivation of cancer inhalation unit risk factors (IURs...

Feb 4, 2019: [Proposed Reference Exposure Levels for Hexamethylene Diisocyanate (Monomer and Polyisocyanates) - Scientific Review Panel Draft]

A draft of the HDI REL document was released for a 75-day public review and comment period on December 1, 2017. One set of comments was received. Those comments and the OEHHA responses to those...

Aug 16, 2018: [Notice of Adoption of Cancer Inhalation Unit Risk and Slope Factors and Cancer Oral Slope Factor for Tert-Butyl Acetate]

The Office of Environmental Health Hazard Assessment (OEHHA) is adopting a new cancer inhalation unit risk factor (IUR) for tert-butyl acetate (TBAc). IURs are used to estimate lifetime cancer risks...

May 4, 2018: [Notice of Adoption of Reference Exposure Levels for Ethylene Glycol Mono-N-Butyl Ether]

The adopted RELs cover different types of exposure to EGBE in air: infrequent 1-hour exposures, repeated 8-hour exposures, and continuous long-term exposure.

Jan 26, 2018: [Extension of Public Comment Period for the Proposed Reference Exposure Levels for Toluene]

OEHHA received a request from the to extend the public comment period. This notice extends the comment period to February 14, 2018.

Dec 19, 2017: [Extension of Public Comment Period for the Proposed Reference Exposure Levels for Hexamethylene Diisocyanate]

This notice extends the comment period to February 14, 2018.

Dec 5, 2017: [Tertiary-Butyl Acetate (TBAc) Inhalation Cancer Unit Risk Factor (IUR) Document - Scientific Review Panel on Toxic Air Contaminants (SRP) Review Draft]

This document will be reviewed and discussed by the Scientific Review Panel on Toxic Air Contaminants at its meeting on December 13, 2017 in Sacramento, CA.

Dec 1, 2017: [Public Comment Period and Workshops on the Draft Reference Exposure Levels for Hexamethylene Diisocyanate and Toluene]

The Office of Environmental Health Hazard Assessment (OEHHA) is releasing two draft documents for public review, summarizing the toxicity and derivation of proposed Reference Exposure Levels (RELs)

Feb 21, 2017: [Notice of Adoption of Reference Exposure Levels for Carbonyl Sulfide]

Adoption of Reference Exposure Levels (RELs) for carbonyl sulfide (COS) for use in the Air Toxics Hot Spots Program

Nov 14, 2016: Ethylene Glycol n-mono Butyl Ether (EGBE) RELs – Draft for Scientific Review Panel on Toxic Air Contaminants (SRP)

EGBE REL document revised in response to the comments made by the SRP during the March 4, 2016 meeting. The values proposed are: Acute REL: 4700 µg/m3, 8–Hour REL: 164 µg/m3, Chronic REL: 82 µg/m3

Nov 14, 2016: Tertiary-Butyl Acetate (TBAc) Cancer Unit Risk Factor (URF) Document - Scientific Review Panel on Toxic Air Contaminants (SRP) Review Draft

Revised draft document summarizing the carcinogenicity and derivation of an inhalation cancer unit risk factor (URF) for tertiary-Butyl Acetate (TBAc).

Sep 8, 2016: Notice of Adoption of Inhalation Cancer Unit Risk Factor for Perchloroethylene

Revised inhalation cancer Unit Risk for perchloroethylene is: 6.1 x 10-6 (µg/m3)-1, the inhalation Cancer Slope Factor is 2.1 x 10-2 (mg/kg-day)-1

Jun 10, 2016: Perchloroethylene Unit Risk Factor – Review Draft for Scientific Review Panel on Toxic Air Contaminants

The SRP Review Draft inhalation cancer Unit Risk for perchloroethylene is: 6.1 x 10-6 (µg/m3)-1, the Cancer Slope Factor is 2.1 x 10-2 (mg/kg-day)-1

Mar 28, 2016: Notice of Adoption of Reference Exposure Levels for Toluene Diisocyanate and Methylene Diphenyl Diisocyanate

Adoption of Reference Exposure Levels (RELs) for toluene diisocyanate (TDI) and methylene diphenyl diisocyanate (MDI) for use in the Air Toxics Hot Spots program. The REL values for TDI are: Acute: 2...

Feb 16, 2016: Public Comment Period and Workshops on Draft Inhalation Cancer Unit Risk Factor for Perchloroethylene

Revised potency values for PCE are based on the elevated incidence of several tumor types observed in male mice and rats. Unit Risk Factor 6.1 E-06 (µg/m3)-1 Slope Factor 2.1E-02 (mg/kg-day)-1.

Feb 3, 2016: Ethylene Glycol n-mono Butyl Ether (EGBE) RELs - Scientific Review Panel on Toxic Air Contaminants (SRP) Review Draft

SRP Review draft for Ethylene Glycol n-mono Butyl Ether (EGBE) proposes the following guidance values: Acute REL of 4700 (µg/m3); 8–Hour REL of 150 µg/m3; and a Chronic REL of 77 µg/m3.

May 21, 2015: Draft Reference Exposure Levels for Carbonyl Sulfide

After a comment period where no comments were received, OEHHA released its updated draft Reference Exposure Levels for carbonyl sulfide for its upcoming Scientific Review Panel meeting.

May 20, 2015: Proposed Reference Exposure Levels for Toluene Diisocyanate and Methylene Diphenyl Diisocyanate – SRP Drafts 2015

OEHHA released revised drafts of its Reference Exposure Levels for Toluene Diisocyanate and Methylene Diphenyl Diisocyanate, which reflected updates requested by the Scientific Review Panel.

Mar 6, 2015: Notice of Adoption of Air Toxics Hot Spots Program Guidance Manual for the Preparation of Health Risk Assessments 2015

Current Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments

Reference: https://oehha.ca.gov/air/air-toxics-hot-spots accessed 4/14/2020

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Revised Health Risk Assessment

Updated Health Risk Assessment
Kern County DEIR –
Proposed Drilling and Oil and Gas Operations

<u>Prepared by:</u>

Environmental Compliance Solutions, Inc.

171 Pier Avenue #337
Santa Monica, CA 90405

September 2015

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1.0 - PROJECT OVERVIEW

This Health Risk Assessment (HRA) has been updated to incorporate comments received on the Draft Environmental Impact Report (DEIR) prepared for the proposed Amendment to Title 19 – Kern County Zoning Ordinance – Chapter 19.98 for Oil and Gas Local Permitting.

The HRA completed for the DEIR and this FEIR was based on very conservative assumptions; **one of which was to assume that all receptor locations contain sensitive receptors.**

Sensitive Receptors are defined as people that have an increased sensitivity to air pollution or environmental contaminants are considered to be sensitive receptors. Sensitive receptor locations include schools, parks and playgrounds, day care centers, nursing homes, hospitals, and residential dwelling unit(s). Within each sensitive receptor, it was assumed that children were residing or located at the site. The location of the nearest sensitive receptors to a project site is needed to assess toxic impacts on public health.

California's Office of Environmental Health Hazard Assessment (OEHHA) is tasked with determining the relative toxicity of numerous chemicals and compounds and is also in charge of determining how California's regulatory HRAs will be conducted. HRAs determine the probability that a sensitive receptor may get cancer from a predetermined exposure to certain chemicals, substances or environments.

OEHHA, in conjunction with the California Air Resources Board (ARB), is also responsible for developing guidelines for how an HRA must be conducted. The HRA conducted for the proposed program followed the OEHHA Guidelines as amended in March 2015. The latest version of the Guidance Manual updates the previous version (OEHHA, 2003), and reflects advances in the field of risk assessment along with new more conservative consideration given to infants and children and their associated inhalation rates. The new guidelines are significantly more stringent than the 2003 predecessor and this is the document that was used for the DEIR and FEIR.

The San Joaquin Valley Air Pollution Control District (SJVAPCD) submitted a comment letter on September 11, 2015 regarding the HRA for the DEIR. They requested changes to ensure that the HRA is consistent with their regulatory risk policy which was recently updated. All of the SJVAPCD's recommended changes were incorporated into this revised HRA and are summarized herein:

1) The air district requested that diesel exhaust be modeled as particulate matter of 10 microns or less (PM10) rather than PM2.5 which was previously modeled. This overstates emissions and risk as PM10 includes dust which is not considered to be toxic by OEHHA. This more conservative analysis is included with this revised HRA.
2) The receptor grid spacing has been adjusted per the SJVAPCD's request.
3) Additional meteorological station data were incorporated.
4) One additional modeling location and modeling study was selected in the Western Subarea by the SJVAPCD.
5) They also revised the location of the Eastern subarea location.

6) SJVAPCD suggested referring to the previous Western subarea as Midway Sunset, the new Western subarea location as Derby Acres, the Central subarea as Shafter and the relocated Eastern Subarea as Kern River.
7) Drilling rigs were requested to be modeled as point sources rather than volume sources.
8) Flare emission factor updates were provided by the SJVAPCD and were used in these calculations.
9) The exhaust parameters for the 1,000 horsepower (hp) natural gas-fired internal combustion engine (ICE) were modified by SJVAPCD.
10) SJAPCD utilizes a 70-year residential exposure assumption in HRAs as compared to OEHHA's HARP2 guidelines which require a 30-year residential exposure.
11) The air district requested that the possibility of home-grown food exposure be included in the analysis. This is not part of the State of California guidelines however it has been included in this revised analysis.
12) Finally, SJVAPCD requested that the results be compared against the SJVAPCD CEQA significance threshold for Toxic Air Contaminants of 20 in one million (20×10^{-6}).

This revised HRA evaluates potential calculated cancer risk and acute and chronic health risk from toxic emissions associated with well construction, drilling, and completion as well as oil and gas processing equipment.

None of the equipment assumptions for well drilling or operational activities have changed. Typical well construction phasing and equipment lists were provided as part of our scope of work; along with emission calculations from all well drilling equipment. All well construction emissions were assumed to occur simultaneously for worst case, conservative assumptions.

As stated above, OEHHA released a new HRA guidance document and software in March 2015. This new program was used to complete this analysis. Use of the new methodology results in calculated risk three to six times higher (300% - 600%) than results for the same emissions profiles using the model previously required for use from 1990 through February 2015.

SJVAPCD released its updated risk assessment guidance on May 28, 2015. The Hot Spots Analysis and Reporting Program, Release Version 2 (HARP2) software was revised on June 29, 2015 (Version 15180), and again on July 16, 2015 (Version 15197). Version 15197 was used for this HRA.

2.0 - HEALTH RISK ASSESSMENT OVERVIEW

As recommended by the OEHHA guidelines, HARP2 (CARB, 2015) was used to perform a refined HRA for potential future drilling 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 United States Environmental Protection Agency (USEPA's) AERMOD model and the risk model includes the latest changes made by OEHHA to the Risk Assessment inputs.

In general, risk assessments involve four steps:

1) Emissions Estimations of Hazardous Air Pollutants;
2) Exposure Assessments;
3) Dose-response Assessments; and
4) Potential Health Risk Quantification.

Emissions Estimations of Hazardous Air Pollutants

Emission estimates involve identifying and quantifying emissions of potential regulated toxic substances from each source. OEHHA guidance regarding whether the pollutants are carcinogenic or possibly associated with short-term or long-term non-cancer health impacts was followed. Toxic emissions from each source were quantified.

“Hazardous air pollutants” is a term used by the federal Clean Air Act (CAA) that includes a variety of pollutants generated or emitted by industrial production activities. HAPs are also referred to as Toxic Air Contaminants (TACs) under the California Clean Air Act of 1988 (CCAA). California listed diesel exhaust or diesel particulate matter (DPM) as a toxic air contaminant in 1998. 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 mode.

The DPM toxicity number incorporates the cumulative health effects of all of the constituents of diesel exhaust into one risk number. Therefore, the only TAC associated with diesel equipment from well construction and completion is DPM. The primary TACs of concern for this project are diesel exhaust associated with construction equipment and drill rigs and benzene (associated with oil processing equipment).

DPM was analyzed from drilling operations. Drilling operations also include an assumption that a drilling mud sump will be required for each well drilled. Potential fugitive emissions of hydrocarbons (VOCs) can be emitted from drilling mud sumps. Those emissions were also included in both the original HRA and this revised HRA. . Potential health effects from both are summarized here. Although the oil processing equipment scenarios did not result in off-site risk greater than 10 in one million, the risk measured was attributed to benzene, formaldehyde and polycyclic aromatic hydrocarbons (PAHs). All three are byproducts of natural gas combustion.

Diesel Particulate Matter

Respirable particles (particulate matter less than about 10 micrometers in diameter [PM_{10}]) can accumulate in the respiratory system and aggravate health problems such as asthma, bronchitis, and other lung diseases. Children, the elderly, exercising adults, and those suffering from asthma are especially vulnerable to adverse health effects of PM_{10} and $PM_{2.5}$. For purposes of this study, all PM2.5 from diesel equipment associated with well drilling (including potential dust and mobile equipment) is conservatively assumed to be toxic diesel particulate matter. DPM represents 100% of the risk number associated with well drilling risk as it is the only compound expected to be emitted.

Benzene

The primary risk driver from oil processing equipment is benzene. Benzene is naturally occurring in oil and gas. Approximately 84 percent of the benzene emitted in California comes from motor vehicles, including evaporative leakage and unburned fuel exhaust. Currently, the benzene content of gasoline is less than 1 percent.

Benzene is potentially carcinogenic and naturally occurs throughout California. Benzene also has noncancer health effects. 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 liquid and vapor may irritate the skin, eyes, and upper respiratory tract in humans. Redness and blisters may result from dermal exposure to benzene.

Formaldehyde

Formaldehyde is a colorless, flammable, chemical typically used in building materials and many household products such as pressed-wood, particle board, plywood; glues and adhesives. Formaldehyde is also naturally occurring in the environment. It is a by-product of natural gas combustion.

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 by-products of natural gas combustion.

Well Drilling Emissions

Seven phases of drilling were considered as detailed below. All particulate matter 10 microns (PM10) was considered to be toxic DPM. This significantly overstates true emissions a portion of the PM10 calculated included road dust and other sources of fugitive dust associated with well pad construction, well drilling and completion.

Well depths of 2,000', 5,000', 10,000' and 15,000' were evaluated. Using a very conservative approach, emissions from all seven phases were assumed to occur simultaneously. An initial year of 2015 was modeled and the final year of 2029/2035 was modeled. CARB's OFFROAD emissions estimate model was used to calculate emissions from the primarily mobile and off-road diesel equipment. CARB has extensive regulations for diesel equipment with future compliance dates that will result in significant emission reductions of PM10 over time.

NOTE: CARB's model includes currently adopted diesel regulations designed to reduce emissions from various off-road and on-road engines. No emission reductions are included in future year calculations for potential reductions from proposed or potential additional regulations that may be required in the future.

CARB's OFFROAD model can only project emissions to 2029 based on today's available engine technologies. As a result, all emissions between 2029 – 2035 are calculated to be the same maximum daily amount.

For this analysis, the following sources were included for evaluation:

- Well drilling (all aspects of construction, well drilling and completion) for a 2,000', 5,000', 10,000', and a 15,000' well.

Each well evaluation consists of the following phases:

- Land Preparation;
- Drilling Survey;
- Well Drilling;
- Well Completion;
- Well Flowline;
- Pump Unit; and
- Electrical.

Numbers and types of equipment associated with each well depth are listed below. An exact equipment list for each of the seven phases and their associated emissions is included as Appendix B.

Both drilling and operational emissions are assumed to occur along a fenceline shared by an oil producer and a private resident (i.e., sensitive receptors).

Table 1 – Equipment Associated with Well Construction, Drilling and Completion*

Depth Feet	Number of Trucks	Off-Road Construction Equip.	Drill Rig HP totals	Drilling Days
15,000	10	54	3 rigs at 1,040 HP each	65
10,000	9	45	3 rigs at 1,040 HP each	23
5000	9	45	3 rigs at 440 HP each	8
2000	9	45	3 rigs at 440 HP each	4

*As previously noted, this equipment is for the combined operation of all seven phases of construction, drilling and completion.

Table 2 – Emissions Associated with Well Constriction, Drilling and Completion

Depth Feet	Year[1]	Total PM10[2] pounds	Annual PM10[3] pounds	Days[4]
15,000	2015	1,626.80	23.24	65
10,000	2015	516.89	17.23	23
10,000	2018	444.00	14.8	23
10,000	2035	151.83	5.06	23
5000[5]	2015	171.18	5.71	8
5000	2035	35.86	1.20	8
2000	2015	97.12	3.24	4
2000	2035	20.42	0.68	4

[1]2029-2035 emissions are the same.
[2]From Vector Environmental Spreadsheet titled “DRL_EMISSIONS.xlsx”, worksheet “EMF”.
[3]Total emissions divided by 30 years per OEHHA’s HARP2 exposure duration requirements.
[4]From Vector Spreadsheet titled “DRL_EMISSIONS.xlsx”, worksheet “MUD”.
[5]Note: 5,000’ wells were not re-modeled as part of the revised HRA since previous results were less than 10 in one million.

Operational Equipment Emissions

Maximum daily and annual emissions were also quantified from an oil processing facility and a natural gas combustion facility. The equipment list and parameters was provided as part of our Scope of Work.

Oil and Gas Processing Equipment

Emissions from the following equipment were analyzed in the oil and gas processing HRA scenario:

- Two – 1,000 Bbl above-ground tanks;
- One – 3,000 Bbl above-ground tank;
- One - 10 MMBtu/hour Flare;
- One - Truck loading rack;
- Fugitive emissions from valves, flanges, and one underground sump;
- Thermally enhanced oil recovery (TEOR) equipment;
- One - 100 MMBtu/hour flare;
- One – 8 MMBtu/hour Process Heater;
- One – 10 MMBtu/hour Boiler;
- One – 85 MMBtu/hour Steam Generator; and
- One – 33 MW Cogeneration Plant.

Potential toxic emissions from each of these devices are summarized in Appendix A.

3.0 - EXPOSURE ASSESSMENT

Exposure assessment includes air dispersion modeling, identification of emission exposure routes and estimation of exposure levels. The modeling estimates ground level concentrations based on an emission rate of one gram per second. This rate is then multiplied by the worst case potential emission rate for each substance to obtain ground level concentrations. In addition to inhalation, potential pathways of exposure to offsite receptors include dermal exposure and ingestion.

HARP2 incorporates the USEPA AERMOD (v14134) model. AERMOD predicts resulting cumulative concentrations from various emission sources. The rural setting was selected in AERMOD for this analysis. AERMOD's terrain processor, AERMAP, was used to incorporate actual terrain elevations for sources and receptors. Five years of meteorological data required for AERMOD was obtained from the SJVAPCD. Data from the Bakersfield (Kern River), Fellows (Derby Acres), Missouri Triangle (Midway Sunset) and Wasco (Shafter) Stations were utilized. The USTAR option, a non-regulatory option, was requested by SJVAPCD.

Four different locations within Kern County were assessed in order to capture various terrain characteristics within the County. Two of the four areas: Derby Acres and Kern River were selected by the air district and two were assessed as being representative of the remaining area of the county.

These areas were previously determined as being representative of various aspects of the county and were included as part of the Scope of Work in the DEIR: Western, Central and Eastern Kern County.

- Western Subarea – Midway Sunset Oilfield
- Central Subarea – No. Shafter Oilfield
- Eastern Subarea – Kern River Oilfield

SJVAPCD added an additional Western Area of complex terrain known as Derby Acres and asked that this area also be modeled. They moved the Midway Sunset previous location over about a mile and they moved the Kern River location to another Kern River location about 8 miles away. The Central Subarea is the exact same location in the original HRA and the revised HRA.

Terrain in the Central Subarea is relatively flat and modeling results would best represent dispersion characteristics with minimal terrain disturbances. More site location and terrain specific influences were observed in the Western Subarea and even more in the Eastern Subarea. Sufficient analysis of different factors that affect dispersion and other modeling inputs were covered by modeling three separate areas within Kern County. The Derby Acres location is a "bowl-type" setting which allows for minimal air dispersion in the immediate vicinity of the selected location.

The rural setting in AERMOD was selected and the model selects the terrain variability based on real-world conditions.

Table 3 shows the UTM location of the project centers for each selected Subarea.

Table 3 - Modeled Kern County Project Locations

Subarea	Easterly	Northerly
Western – Midway Sunset[1]	255,000	3918,100
Central – Shafter[1]	293,650	3934,400
Western – Derby Acres[2]	264,075	3904,580
Eastern – Kern River[2]	320,540	3922,785

[1]Based on Subarea modeling locations provided by Vector dated 2/15/2015 and rounded to the nearest 164 feet. (UTM NAD83, Zone 11)
[2]Provided by SJVAPCD

Source Modeling Parameters

Potential sources were modeled as described in the table below. Both drilling and operational emissions are assumed to occur along a fenceline shared by an oil producer and a private residence (i.e., sensitive receptor).

Table 4 - Modeling Source Characteristics and Release Parameters

Point Sources				
Source Name	Height, meters	Temp, ºK	Velocity, mps	Diameter, meters
Drilling	2.85	761.9	71.2	0.18
10 MMBtu/hr Flare[1]	10.79	1088.7	56.3	0.64
100 MMBtu/hr Flare[1]	13.85	1088.7	56.3	2.03
85 MMBtu/hr Steam Generator[2]	6.10	366.5	21.4	0.76
33 MW Cogen	9.14	806.0	20.7	3.05
8 mm Btu/hour process heater[2]	4.57	588.7	9.11	0.46
1000 bhp Natural Gas Engine[2]	6.78	745.2	3063.9	0.35
10 mm Btu/hour boiler[2]	6.10	477.6	7.3	0.46

Area Sources			
Source Name	Release Height, meters	X, meters	Y, meters
Fugitive leaks	1.00	10.00	10.00
Sump	0	9.14	9.14
Drilling Mud Sump	0	10.00	10.00
TEOR	0	5.00	5.00

Circular Area Sources		
Source Name	Height, meters	Radius, meters
1000 Bbl Tank	4.88	3.28
1000 Bbl Tank	4.88	3.28
3000 Bbl Tank	7.35	4.53

Volume Sources			
Source Name	Release Height, meters	Initial Lateral Dimension, meters	Initial Vertical Dimension, meters
Vacuum Truck Loading	4	0.60	0.93

[1]Adjusted per SJVAPCD EPA methodology.
[2]Per Scope of Work amendment 2-15-2015.
[3]Tank dimensions from tank vendor website.

4.0 - 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 OEHHA 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 OEHHA an HRA.

Exposure Pathways

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 (diesel particulate matter) in the environment.

For this analysis, HARP2 requires assumptions that diesel particulate matter could also be ingested via dermal (skin) absorption, soil ingestion and mother's milk ingestion. PAHs were the only pollutants analyzed for which there is a non-inhalation pathway.

The following table represents the relative toxicity of the compounds which contributed to most of the calculated risk. For example, DPM (with an inhalation potency factor of 1.1) is approximately 10 times more toxic than benzene (inhalation potency factor of 0.10) and PAHs are almost four times more toxic than DPM.

Table 5 - Chemical Cancer Risk Factors[1]

Chemical	Inhalation Unit Risk[2]	Inhalation Potency Factor[2]	Non-Inhalation Oral Slope Factor
	$(\mu g/m^3)^{-1}$	$(mg/kg\text{-}d)^{-1}$	$(mg/kg\text{-}d)^{-1}$
Diesel Particulate Matter	0.0003	1.1	NA (inhalation only)
Total PAHs[3]	0.001	3.9	12.0
Formaldehyde	0.000006	0.02	NA (inhalation only)
Benzene	0.029	0.10	NA (inhalation only)

[1]May 13, 2015.

[2]Inhalation cancer potency factor: The "unit risk factor" has been replaced in the new risk assessment algorithms by a factor called the "inhalation cancer potency factor". Inhalation cancer potency factors are expressed as units of inverse dose [i.e., (mg/kg-day)-1]. They were derived from unit risk factors [units = (ug/m3)-1] by assuming that a receptor weighs 70 kilograms and breathes 20 cubic meters of air per day. The inhalation potency factor is used to calculate a potential inhalation cancer risk using the new risk assessment algorithms defined in the OEHHA, *Air Toxics Hot Spots Program; Technical Support Document for Exposure Assessment and Stochastic Analysis (August 2012)*.

[3]Polycyclic Aromatic Hydrocarbons (PAHs): (Not including naphthalene.) These substances are PAH or PAH-derivatives that have OEHHA-developed Potency Equivalency Factors (PEFs) which were approved by the Scientific Review Panel in April 1994 (see ARB document entitled *Benzo[a]pyrene as a Toxic Air Contaminant*). PAH inhalation slope factors listed here have been adjusted by the PEFs. See OEHHA's Technical Support Document: Methodologies for Derivation, Listing of Available Values, and Adjustments to Allow for Early Life Exposures (2009) for more information about the scheme. Section 8.2.3 and Appendix G of OEHHA's *The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments (2003)* also contains information on PAHs.

5.0 - SIGNIFICANCE THRESHOLDS

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 20 in one million
- Chronic hazard index equal to or less than 1
- 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).

6.0 - HEALTH RISK ASSESSMENT RESULTS

None of the modeling scenarios exceed a 20 in one million risk.

A revised refined HRA was performed again using the HARP2 model. As shown, calculated cancer risk from drilling a 15,000' well exceeds a threshold of 10 cases in one million (Table 6) at only one location – the Western Derby Acres site. At a distance of 182 feet, risk is below 10 in one million.

None of the other drilling scenarios exceed a 10 in one million risk.

The scenario in which all of the oil and gas processing equipment operates full time and is located in the exact same location with a shared fenceline to private property results in 20 in one million risk level from 164 – 295 feet depending on the subarea of Kern County (Table 8).

None of the noncancer hazards for either an oil processing facility or a gas processing facility exceed the regulatory threshold of 1.0 (Tables 9 and 10).

Table 6 –

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	Maximum distance from well site and project boundary to 20 in one million calculated risk
Western Subarea – Midway Sunset			
15,000	2017	NA*	NA
10,000	2015	NA	NA
10,000	2020	NA	NA
10,000	2029	NA	NA
5000	2015	NA	NA
5000	2029	NA	NA
2000	2015	NA	NA
2000	2029/2035	NA	NA
Central Subarea - Shafter			
15,000	2017	NA	NA
10,000	2015	NA	NA
10,000	2020	NA	NA
10,000	2029	NA	NA
5000	2015	NA	NA
5000	2029	NA	NA
2000	2015	NA	NA
2000	2029/2035	NA	NA
Eastern Subarea – Kern River			
15,000	2017	NA	NA
10,000	2015	NA	NA
10,000	2029	NA	NA
5000	2015	NA	NA
5000	2029	NA	NA
2000	2015	NA	NA
2000	2029/2035	NA	NA
Western Subarea – Derby Acres			
15,000	2017	182 feet	NA

*NA = no offsite risk greater than 10 in one million.

Table 7 –
Potential health risks from all oil processing equipment

Equipment	**Western Subregion – Derby Acres Cancer Risk Distances**	**Western Subregion – Midway Sunset Cancer Risk Distances**	**Central Subregion Cancer Risk Distances**	**Eastern Subregion Cancer Risk Distances**
1,000 bbl oil tank				
1,000 bbl oil tank				
3,000 bbl oil tank				
truck loading rack				
30’x30’ sump				
10,000 btu/hour flare				
Fugitive VOCs				
1,000 bhp natural gas engine				
100 mmbtu/flare				
35 mm btu/hour steam generator				
8 mm btu/hour boiler				
33 mw cogen				
TEOR equipment				
TOTAL CUMULATIVE RISK Distances to 10 in one million	518’	296’	366’	295’
TOTAL CUMULATIVE RISK Distances to 20 in one million	246’	295’	164’	259’

*Risk distances assume that all equipment is placed along a shared fence line between the oil site
and a private residence.

NOTE: All of this equipment would require SJVAPCD air permits. As such, the risk threshold must be complied with or permits cannot be issued. Under this scenario, either less equipment could be used and/or the receptors cannot share a fence line in order to obtain permits.

Table 9
Potential Acute Impacts

Equipment	**Western Subregion *Midway Sunset* Acute Risk**	**Western Subregion *Derby Acres* Acute Risk**	**Central Subregion Acute Risk**	**Eastern Subregion Acute Risk**	**Hazard Index Standard**	**Significant?**
Drilling Emissions 10,000' well	0.0039	0.0018	0.0098	0.0090	1.0	No
Oil and Gas Processing Emissions	0.008	0.23	0.01	0.14	1.0	No

Table 10

Potential Chronic (Non Cancer Impacts)

Equipment	**Western Subregion *Midway Sunset* Chronic Risk**	**Western Subregion *Derby Acres* Chronic Risk**	**Central Subregion Chronic Risk**	**Eastern Subregion Chronic Risk**	**Hazard Index Standard**	**Significant**
Drilling Emissions 10,000’ well	0.003	0.0018	0.006	0.002	1.0	No
Oil and Gas Processing Emissions	0.30	0.3	0.46	0.18	1.0	No

7.0 - REFERENCES

California Code of Regulations, Title 22, Division 2, Chapter 3, Section 12000 "Safe Drinking Water and Toxic Enforcement Act of 1986." California regulations can be downloaded at the following link: http://www.oal.ca.gov/.

CARB. 2015. "HARP User Guide." The document can be downloaded at the following link: http://www.arb.ca.gov/toxics/harp/harpug.htm

SCAQMD. 2007. "General Instruction Book for the 2006-2007 Annual Emission Reporting Program." The document can be downloaded at the following link: http://www.ecotek.com/aqmd/2006/forms_and_instructions_pdf/0607_GuideBook.pdf

SCAQMD. 2005. "Risk Assessment Procedures for Rules 1401 and 212". The document can be downloaded at the following links: http://www.aqmd.gov/prdas/pdf/riskassessmentprocedures-v7.pdf and http://www.aqmd.gov/prdas/pdf/attachmentpkg-l.pdf.

SCAQMD. 2005. "Supplemental Guidelines for Preparing Risk Assessments for the Air Toxics "Hot Spots" Information and Assessment Act (AB2588). The document can be downloaded at the following link: http://www.aqmd.gov/prdas/AB2588/pdf/AB2588_Guidelines.pdf.

United States Environmental Protection Agency (U.S. EPA) 2004. User's Guide for the AMS/EPA Regulatory Model – AERMOD, EPA-454/B-03-001.

Meteorological data used by AERMOD was obtained by SJVAPCD for Bakersfield Station 23155.

OEHHA. 2003. "The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments." The document can be downloaded at the following link:http://www.oehha.ca.gov/air/hot_spots/HRSguide.html.

Vector Environmental: Emissions from Offroad Mobile Sources and Portable Equipment Required for the Construction of Wells. 2015. Criteria pollutant emission data by activity, phase and task for years 2012-2029.

Vector Environmental: MS Excel spreadsheet entitled: "DRL_EMISSIONS.xlsx".

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Appendix A

Toxic Air Contaminants by Device

Source Name	Source ID	CAS #	Chemical Name	Pounds/year	Pounds/hour
Fugitive VOCs	FHC01	95636	"1,2,4 Trimethylbenzene"	0.01	0.00
Fugitive VOCs	FHC01	71432	Benzene	0.32	0.00
Fugitive VOCs	FHC01	110827	Cyclohexane	0.02	0.00
Fugitive VOCs	FHC01	100414	Ethylbenzene	0.10	0.00
Fugitive VOCs	FHC01	110543	n-Hexane	2.38	0.00
Fugitive VOCs	FHC01	108883	Toluene	0.36	0.00
Fugitive VOCs	FHC01	1330207	Xylenes	0.19	0.00
Fugitive VOCs	FHC01	7783064	Hydrogen sulfide	2.02	0.00
10 MMBtu/hr Flare	FLR01	75070	Acetaldehyde	3.77	0.00
10 MMBtu/hr Flare	FLR01	107028	Acrolein	0.88	0.00
10 MMBtu/hr Flare	FLR01	71432	Benzene	13.93	0.00
10 MMBtu/hr	FLR01	110827	Cyclohexane	0.00	0.00

Flare					
10 MMBtu/hr Flare	FLR01	100414	Ethylbenzene	126.49	0.01
10 MMBtu/hr Flare	FLR01	50000	Formaldehyde	102.40	0.01
10 MMBtu/hr Flare	FLR01	110543	n-Hexane	2.54	0.00
10 MMBtu/hr Flare	FLR01	7783064	Hydrogen sulfide	15.70	0.00
10 MMBtu/hr Flare	FLR01	91203	Naphthalene	0.96	0.00
10 MMBtu/hr Flare	FLR01	1151	PAH's	1.23	0.00
10 MMBtu/hr Flare	FLR01	115071	Propylene	213.74	0.02
10 MMBtu/hr Flare	FLR01	108883	Toluene	5.08	0.00
10 MMBtu/hr Flare	FLR01	1330207	Xylenes	2.54	0.00
Sump	SMP01	95636	"1,2,4 Trimethylbenzene"	0.23	0.00
Sump	SMP01	71432	Benzene	6.78	0.00
Sump	SMP01	110827	Cyclohexane	0.33	0.00

Sump	SMP01	100414	Ethylbenzene	2.16	0.00
Sump	SMP01	110543	n-Hexane	50.00	0.01
Sump	SMP01	108883	Toluene	7.60	0.00
Sump	SMP01	1330207	Xylenes	4.01	0.00
Sump	SMP01	7783064	Hydrogen sulfide	0.49	0.00
Truck Loading Rack	LDR01	95636	"1,2,4 Trimethylbenzene"	0.63	0.00
Truck Loading Rack	LDR01	71432	Benzene	18.92	0.00
Truck Loading Rack	LDR01	110827	Cyclohexane	0.92	0.00
Truck Loading Rack	LDR01	100414	Ethylbenzene	6.02	0.00
Truck Loading Rack	LDR01	110543	n-Hexane	139.46	0.02
Truck Loading Rack	LDR01	108883	Toluene	21.20	0.00
Truck Loading Rack	LDR01	1330207	Xylenes	11.18	0.00
Truck Loading Rack	LDR01	7783064	Hydrogen sulfide	1.36	0.00
Oil Storage Tank (1,000 bbls)	TNK03	95636	"1,2,4 Trimethylbenzene"	0.75	0.00

Oil Storage Tank (1,000 bbls)	TNK03	71432	Benzene	22.45	0.00
Oil Storage Tank (1,000 bbls)	TNK03	110827	Cyclohexane	1.10	0.00
Oil Storage Tank (1,000 bbls)	TNK03	100414	Ethylbenzene	7.15	0.00
Oil Storage Tank (1,000 bbls)	TNK03	110543	n-Hexane	165.48	0.02
Oil Storage Tank (1,000 bbls)	TNK03	108883	Toluene	25.16	0.00
Oil Storage Tank (1,000 bbls)	TNK03	1330207	Xylenes	13.26	0.00
Oil Storage Tank (1,000 bbls)	TNK03	7783064	Hydrogen sulfide	1.62	0.00
Oil Storage Tank (1,000 bbls)	TNK02	95636	"1,2,4 Trimethylbenzene"	0.75	0.00
Oil Storage Tank (1,000 bbls)	TNK02	71432	Benzene	22.45	0.00
Oil Storage Tank (1,000 bbls)	TNK02	110827	Cyclohexane	1.10	0.00
Oil Storage Tank (1,000 bbls)	TNK02	100414	Ethylbenzene	7.15	0.00

Oil Storage Tank (1,000 bbls)	TNK02	110543	n-Hexane	165.48	0.02
Oil Storage Tank (1,000 bbls)	TNK02	108883	Toluene	25.16	0.00
Oil Storage Tank (1,000 bbls)	TNK02	1330207	Xylenes	13.26	0.00
Oil Storage Tank (1,000 bbls)	TNK02	7783064	Hydrogen sulfide	1.62	0.00
Oil Storage Tank (3,000 bbls)	TNK01	95636	"1,2,4 Trimethylbenzene"	0.60	0.00
Oil Storage Tank (3,000 bbls)	TNK01	71432	Benzene	17.73	0.00
Oil Storage Tank (3,000 bbls)	TNK01	110827	Cyclohexane	0.87	0.00
Oil Storage Tank (3,000 bbls)	TNK01	100414	Ethylbenzene	5.64	0.00
Oil Storage Tank (3,000 bbls)	TNK01	110543	n-Hexane	130.72	0.02
Oil Storage Tank (3,000 bbls)	TNK01	108883	Toluene	19.87	0.00
Oil Storage Tank (3,000 bbls)	TNK01	1330207	Xylenes	10.48	0.00

Oil Storage Tank (3,000 bbls)	TNK01	7783064	Hydrogen sulfide	1.28	0.00
Process Heater	PHT01	83329	Acenaphthene	0.00	0.00
Process Heater	PHT01	208968	Acenaphthylene	0.01	0.00
Process Heater	PHT01	75070	Acetaldehyde	1.17	0.00
Process Heater	PHT01	107028	Acrolein	0.20	0.00
Process Heater	PHT01	120127	Anthracene	0.00	0.00
Process Heater	PHT01	56553	Benz(a)anthracene	0.00	0.00
Process Heater	PHT01	71432	Benzene	1.71	0.00
Process Heater	PHT01	50328	Benzo(a)pyrene	0.00	0.00
Process Heater	PHT01	205992	Benzo(b)fluoranthene	0.00	0.00
Process Heater	PHT01	191242	"Benzo(g,h,i)perylene"	0.00	0.00
Process Heater	PHT01	207089	Benzo(k)fluoranthene	0.00	0.00
Process Heater	PHT01	218019	Chrysene	0.00	0.00
Process Heater	PHT01	53703	"Dibenz(a,h)anthracene"	0.00	0.00
Process Heater	PHT01	206440	Fluoranthene	0.00	0.00

Process Heater	PHT01	86737	Fluorene	0.12	0.00
Process Heater	PHT01	50000	Formaldehyde	6.23	0.00
Process Heater	PHT01	7783064	Hydrogen sulfide	12.56	0.00
Process Heater	PHT01	193395	"Indeno(1,2,3-cd)pyrene"	0.00	0.00
Process Heater	PHT01	91203	Naphthalene	0.43	0.00
Process Heater	PHT01	85018	Phenanthrene	0.03	0.00
Process Heater	PHT01	108952	Phenol	0.15	0.00
Process Heater	PHT01	115071	Propylene	0.97	0.00
Process Heater	PHT01	129000	Pyrene	0.00	0.00
Process Heater	PHT01	108883	Toluene	2.12	0.00
Process Heater	PHT01	1330207	Xylenes	2.45	0.00
Steam Generator	SGR01	83329	Acenaphthene	0.00	0.00
Steam Generator	SGR01	208968	Acenaphthylene	0.01	0.00
Steam Generator	SGR01	75070	Acetaldehyde	19.88	0.00
Steam Generator	SGR01	107028	Acrolein	13.55	0.00
Steam	SGR01	120127	Anthracene	0.00	0.00

Generator					
Steam Generator	SGR01	56553	Benz(a)anthracene	0.00	0.00
Steam Generator	SGR01	71432	Benzene	4.62	0.00
Steam Generator	SGR01	50328	Benzo(a)pyrene	0.00	0.00
Steam Generator	SGR01	205992	Benzo(b)fluoranthene	0.00	0.00
Steam Generator	SGR01	191242	"Benzo(g,h,i)perylene"	0.00	0.00
Steam Generator	SGR01	207089	Benzo(k)fluoranthene	0.00	0.00
Steam Generator	SGR01	218019	Chrysene	0.00	0.00
Steam Generator	SGR01	53703	"Dibenz(a,h)anthracene"	0.00	0.00
Steam Generator	SGR01	100414	Ethylbenzene	13.85	0.00
Steam Generator	SGR01	206440	Fluoranthene	0.01	0.00
Steam Generator	SGR01	86737	Fluorene	0.01	0.00
Steam Generator	SGR01	50000	Formaldehyde	52.20	0.01
Steam Generator	SGR01	7783064	Hydrogen sulfide	133.42	0.02
Steam Generator	SGR01	193395	"Indeno(1,2,3-cd)pyrene"	0.00	0.00
Steam Generator	SGR01	91203	Naphthalene	0.41	0.00

Steam Generator	SGR01	85018	Phenanthrene	0.02	0.00
Steam Generator	SGR01	115071	Propylene	469.10	0.05
Steam Generator	SGR01	129000	Pyrene	0.01	0.00
Steam Generator	SGR01	108883	Toluene	22.93	0.00
Steam Generator	SGR01	1330207	Xylenes	30.01	0.00
1,000 hp ICE	ICE01	71432	Benzene	126.21	0.01
1,000 hp ICE	ICE01	50000	Formaldehyde	3118.12	0.36
1,000 hp ICE	ICE01	115071	Propylene	1187.86	0.14
1,000 hp ICE	ICE01	108883	Toluene	57.17	0.01
1,000 hp ICE	ICE01	1330207	Xylenes	28.95	0.00
1,000 hp ICE	ICE01	7783064	Hydrogen sulfide	13.30	0.00
Drilling Emissions	DRL01	9901.00	Diesel Particulate Matter	17.23	1
33 MW Cogen	COG01	71432	Benzene	36.07	0.00
33 MW Cogen	COG01	7783064	Hydrogen sulfide	442.64	0.05
33 MW Cogen	COG01	91203	Naphthalene	14.30	0.00
33 MW	COG01	1151	PAH's	0.63	0.00

Cogen					
33 MW Cogen	COG01	50000	Formaldehyde	454.54	0.05
Drilling Mud Sump	SMP02	95636	"1,2,4 Trimethylbenzene"	0.01	0.00
Drilling Mud Sump	SMP02	71432	Benzene	0.28	0.00
Drilling Mud Sump	SMP02	110827	Cyclohexane	0.01	0.00
Drilling Mud Sump	SMP02	100414	Ethylbenzene	0.09	0.00
Drilling Mud Sump	SMP02	110543	n-Hexane	2.10	0.00
Drilling Mud Sump	SMP02	108883	Toluene	0.32	0.00
Drilling Mud Sump	SMP02	1330207	Xylenes	0.17	0.00
Drilling Mud Sump	SMP02	7783064	Hydrogen sulfide	0.02	0.00
Boiler	BLR01	83329	Acenaphthene	0.00	0.00
Boiler	BLR01	208968	Acenaphthylene	0.00	0.00
Boiler	BLR01	75070	Acetaldehyde	2.34	0.00
Boiler	BLR01	107028	Acrolein	1.59	0.00
Boiler	BLR01	120127	Anthracene	0.00	0.00
Boiler	BLR01	56553	Benz(a)anthracene	0.00	0.00
Boiler	BLR01	71432	Benzene	0.54	0.00
Boiler	BLR01	50328	Benzo(a)pyrene	0.00	0.00
Boiler	BLR01	205992	Benzo(b)fluoranthene	0.00	0.00

Boiler	BLR01	191242	"Benzo(g,h,i)perylene"	0.00	0.00
Boiler	BLR01	207089	Benzo(k)fluoranthene	0.00	0.00
Boiler	BLR01	218019	Chrysene	0.00	0.00
Boiler	BLR01	53703	"Dibenz(a,h)anthracene"	0.00	0.00
Boiler	BLR01	100414	Ethylbenzene	1.63	0.00
Boiler	BLR01	206440	Fluoranthene	0.00	0.00
Boiler	BLR01	86737	Fluorene	0.00	0.00
Boiler	BLR01	50000	Formaldehyde	6.14	0.00
Boiler	BLR01	7783064	Hydrogen sulfide	15.70	0.00
Boiler	BLR01	193395	"Indeno(1,2,3-cd)pyrene"	0.00	0.00
Boiler	BLR01	91203	Naphthalene	0.05	0.00
Boiler	BLR01	85018	Phenanthrene	0.00	0.00
Boiler	BLR01	115071	Propylene	55.19	0.01
Boiler	BLR01	129000	Pyrene	0.00	0.00
Boiler	BLR01	108883	Toluene	2.70	0.00
Boiler	BLR01	1330207	Xylenes	3.53	0.00
Thermally Enhanced Oil Recovery Equipment	TEOR	95636	"1,2,4 Trimethylbenzene"	0.03	0.00
Thermally Enhanced Oil Recovery Equipment	TEOR	71432	Benzene	0.95	0.00
Thermally Enhanced	TEOR	110827	Cyclohexane	0.05	0.00

Oil Recovery Equipment					
Thermally Enhanced Oil Recovery Equipment	TEOR	100414	Ethylbenzene	0.30	0.00
Thermally Enhanced Oil Recovery Equipment	TEOR	110543	n-Hexane	6.98	0.00
Thermally Enhanced Oil Recovery Equipment	TEOR	108883	Toluene	1.06	0.00
Thermally Enhanced Oil Recovery Equipment	TEOR	1330207	Xylenes	0.56	0.00
Thermally Enhanced Oil Recovery Equipment	TEOR	7783064	Hydrogen sulfide	0.07	0.00
100 MMBtu/hr Flare	FLR02	75070	Acetaldehyde	37.67	0.00
100 MMBtu/hr Flare	FLR02	107028	Acrolein	8.76	0.00
100 MMBtu/hr	FLR02	71432	Benzene	139.28	0.02

Flare					
100 MMBtu/hr Flare	FLR02	110827	Cyclohexane	0.00	0.00
100 MMBtu/hr Flare	FLR02	100414	Ethylbenzene	1264.94	0.14
100 MMBtu/hr Flare	FLR02	50000	Formaldehyde	1024.04	0.12
100 MMBtu/hr Flare	FLR02	110543	n-Hexane	25.40	0.00
100 MMBtu/hr Flare	FLR02	7783064	Hydrogen sulfide	15.70	0.00
100 MMBtu/hr Flare	FLR02	91203	Naphthalene	9.64	0.00
100 MMBtu/hr Flare	FLR02	1151	PAH's	12.26	0.00
100 MMBtu/hr Flare	FLR02	115071	Propylene	2137.44	0.24
100 MMBtu/hr Flare	FLR02	108883	Toluene	50.81	0.01
100 MMBtu/hr Flare	FLR02	1330207	Xylenes	25.40	0.00

Appendix B –

Equipment and Emissions for Well Depths

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2015 Emissions from a 2000 ft. Well

Construction Activity: A1. Land Preparation

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Water Truck	1.0	7.0	8.48	400	3.46
Loader	1.0	4.0	2.5	100	.34
35 Yard Dump Truck	1.0	2 .0	1.00	400	.12
Grader	1.0	4.0	2.5	175	.77
Skip & Scrap (Backhoe)	1.0	1.0	1.0	100	.03
Big Scrapper	1.0	2.0	2.5	362	.47
Dozer (D9R)	1.0	1.0	1.0	255	.08
Low Bed Truck/Trailer	1.0	2.0	.5	400	.06
Dump Truck 10 Wheels	1.0	1.0	.5	400	.03
Backhoe	1.0	2.0	.54	100	.04
Loader	1.0	3.0	2.5	100	.26
Loader	1.0	2.0	1.0	100	.07
Escavator (Backoe/tracks)	1.0	1.0	1.0	163	.03
Dozer (D8T)	1.0	1.0	1.0	255	.08
End Dump Truck & Trailer	1.0	1.0	.50	400	.03
Grader	1.0	1.0	.50	175	.04
Annual Emissions From Offroad Source Activity					5.91

2015 Emissions from a 2000 Ft. Well

Construction Activity: B.1 Drilling Survey

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Rig	1.0	1.0	12.00	100	.58
Cement Truck	1.0	4.0	12.00	400	.70
Annual Emissions From Offroad Source Activity					1.28

2015 Emission from a 2000 Ft. Well

Construction Activity: C.1 Well Drilling

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Crane	1.0	2.0	8.00	230	.81
Port Light Stands	5.0	5.0	12.00	20	2.41
Portable Gen. Hydraulic Power	1.0	5.0	22.00	80	3.66
Portable Gen. DSM/Trailers	2.0	5.0	24.00	100	9.99
Portable Gen. Mud Separator	1.0	4.0	22.00	420	4.65
Rotary Table or Top Drive	1.0	4.0	22.00	135	5.63
Diesel Engine For Hoist	1.0	4.0	22.00	455	6.74
Diesel Engine For Hoist	1.0	4.0	22.0	442	6.55
Diesel Engine for Mud Pump	1.0	4.0	22.00	424	6.28
Annual Emissions From Offroad Source Activity					46.72

2015 Emissions from a 2000 Ft Well

Construction Activity: D.1 Well Completion

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Accumulator Generator	1.0	4.0	24.00	100	4.0
Filter Skid (Pump)	1.0	2.0	3.00	90	.22
Acid Pump #1 (Hydraulic Oil Pump)	1.0	1.0	22.00	175	.85
Acid Pump #2 (Acid Fluid Pumping)	1.0	4.0	22.00	765	2.17
Generator for Doghouse for WO Rig	1.0	4.0	24.00	70	2.8
3 Light Plants for WO Rig	3.0	4.0	12.00	20	1.15
Diesel Engine for COROD or Other	1.0	1.0	22.00	450	1.67
Portable Den. Mud Separator	1.0	4.0	22.00	420	4.65
Rotary Table or Top Drive	1.0	4.0	22.00	135	5.63
Diesel Engine for Hoist	1.0	4.0	22.00	455	6.74
Diesel Engine for Hoist	1.0	3.0	22.00	442	6.55
Diesel Engine for Mud Pump	1.0	4.0	22.00	424	6.28
Annual Emissions From Offroad Source Activity (Lb/Year)					42.71

2015 Emissions from a 2000 Ft. Well

Construction Activity: E.1 Well Flowline

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Side Boom D4/Crawler	1.0	3.0	10.00	520	.92
Backhoe	1.0	3.0	10.00	95	.98
Pipe Fitting or Welders	1.0	3.0	10.00	40	.48
Hydrotest Pump	1.0	1.0	1.00	.08	.01
Forklift	1.0	3.0	10.00	125	.56
Other Equipment/Bending Machine	1.0	3.0	10.00	80	1.12
Annual Emissions From Offroad Source Activity					4.07

2015 Emissions from a 2000 Ft. Well

Construction Activity: F.1 Pump Unit

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Power Generator	1.0	2.0	8.00	10	.06
Backhoe	1.0	2.0	4.00	80	.22
Welder	1.0	2.0	8.00	25	.16
Annual Emissions From Offroad Source Activity					.44

2015 Emissions from a 2000 Ft. Well

Construction Activity: G.1 Electrical

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Line Truck	1.0	4.0	10.00	250	1.73
Bucket Truck	1.0	4.0	10.00	250	1.73
Electrical Service Truck	1.0	4.0	1.00	300	.15
Power Generators	1.0	4.0	1.00	10	.02
Back-Hoe	1.0	1.0	10.00	650	.80
Annual Emissions From Offroad Source Activity					4.43

2015 Emissions from a 5000 ft. Well

Construction Activity: A1. Land Preparation

2015 Emissions from a 5000 Ft. Well

Construction Activity: B.1 Drilling Survey

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Rig	1.0	1.0	12.00	100	.58
Cement Truck	1.0	1.0	12.00	400	.70
Annual Emissions From Offroad Source Activity (Lb/Year					1.28

2015 Emission from a 5000 Ft. Well
Construction Activity: C.1 Well Drilling

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Crane	1.0	2.0	8.00	230	.81
Port Light Stands	5.0	9.0	12.00	20	4.33
Portable Gen. Hydraulic Power	1.0	9.0	22.00	80	6.60
Portable Gen. DSM/Trailers	2.0	9.0	24.00	100	17.99
Portable Gen. Mud Separator	1.0	8.0	22.00	420	9.30
Rotary Table or Top Drive	1.0	8.0	22.00	135	11.26
Diesel Engine For Hoist	1.0	8.0	22.00	455	13.48
Diesel Engine For Hoist	1.0	8.0	22.0	442	13.09
Diesel Engine for Mud Pump	1.0	8.0	22.00	424	12.56
Annual Emissions From Offroad Source Activity					89.42

2015 Emissions from a 5000 Ft Well

Construction Activity: D.1 Well Completion

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Accumulator Generator	1.0	8.0	24.00	100	8.00
Filter Skid (Pump)	1.0	2.0	3.00	90	.22
Acid Pump #1 (Hydraulic Oil Pump)	1.0	1.0	22.00	175	.85
Acid Pump #2 (Acid Fluid Pumping)	1.0	1.0	22.00	765	2.17
Generator for Doghouse for WO Rig	1.0	8.0	24.00	70	5.60
3 Light Plants for WO Rig	3.0	8.0	12.00	20	2.31
Diesel Engine for COROD or Other	1.0	1.0	22.00	450	1.67
Portable Den. Mud Separator	1.0	8.0	22.00	420	9.30
Rotary Table or Top Drive	1.0	8.0	22.00	135	11.26
Diesel Engine for Hoist	1.0	8.0	22.00	455	13.48
Diesel Engine for Hoist	1.0	8.0	22.00	442	13.09
Diesel Engine for Mud Pump	1.0	8.0	22.00	424	12.56
Annual Emissions From Offroad Source Activity (Lb/Year)					80.51

2015 Emissions from a 5000 Ft. Well

Construction Activity: E.1 Well Flowline

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Side Boom D4/Crawler	1.0	3.0	10.00	520	.92
Backhoe	1.0	3.0	10.00	95	.98
Pipe Fitting or Welders	1.0	3.0	10.00	40	.48
Hydrotest Pump	1.0	1.0	1.00	.08	.01
Forklift	1.0	3.0	10.00	125	.56
Other Equipment/Bending Machine	1.0	3.0	10.00	80	1.12
Annual Emissions From Offroad Source Activity					4.07

2015 Emissions from a 5000 Ft. Well

Construction Activity: F.1 Pump Unit

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Power Generator	1.0	2.0	8.00	10	.06
Backhoe	1.0	2.0	4.00	80	.22
Welder	1.0	2.0	8.00	25	.16
Annual Emissions From Offroad Source Activity					.44

2015 Emissions from a 5000 Ft. Well

Construction Activity: G.1 Electrical

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Line Truck	1.0	4.0	10.00	250	1.73
Bucket Truck	1.0	4.0	10.00	250	1.73
Electrical Service Truck	1.0	4.0	1.00	300	.15
Power Generators	1.0	4.0	1.00	10	.02
Back-Hoe	1.0	1.0	10.00	650	.80
Annual Emissions From Offroad Source Activity					4.43

2015 Emissions from a 5000 ft. Well

Construction Activity: A1. Land Preparation

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Water Truck	1.0	7.0	8.48	400	3.46
Loader	1.0	4.0	2.5	100	.34
35 Yard Dump Truck	1.0	2 .0	1.00	400	.12
Grader	1.0	4.0	2.5	175	.77
Skip & Scrap (Backhoe)	1.0	1.0	1.0	100	.03
Big Scrapper	1.0	2.0	2.5	362	.47
Dozer (D9R)	1.0	1.0	1.0	255	.08
Low Bed Truck/Trailer	1.0	2.0	.5	400	.06
Dump Truck 10 Wheels	1.0	1.0	.5	400	.03
Backhoe	1.0	2.0	.54	100	.04
Loader	1.0	3.0	2.5	100	.26
Loader	1.0	2.0	1.0	100	.07
Escavator (Backoe/tracks)	1.0	1.0	1.0	163	.03
Dozer (D8T)	1.0	1.0	1.0	255	.08
End Dump Truck & Trailer	1.0	1.0	.50	400	.03
Grader	1.0	1.0	.50	175	.04
Annual Emissions From Offroad Source Activity (Lb/Year)					5.91

2015 Emissions from a 5000 Ft. Well

Construction Activity: B.1 Drilling Survey

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Rig	1.0	1.0	12.00	100	.58
Cement Truck	1.0	1.0	12.00	400	.70
Annual Emissions From Offroad Source Activity (Lb/Year					1.28

2015 Emission from a 5000 Ft. Well

Construction Activity: C.1 Well Drilling

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Crane	1.0	2.0	8.00	230	.81
Port Light Stands	5.0	9.0	12.00	20	4.33
Portable Gen. Hydraulic Power	1.0	9.0	22.00	80	6.60
Portable Gen. DSM/Trailers	2.0	9.0	24.00	100	17.99
Portable Gen. Mud Separator	1.0	8.0	22.00	420	9.30
Rotary Table or Top Drive	1.0	8.0	22.00	135	11.26
Diesel Engine For Hoist	1.0	8.0	22.00	455	13.48
Diesel Engine For Hoist	1.0	8.0	22.0	442	13.09
Diesel Engine for Mud Pump	1.0	8.0	22.00	424	12.56
Annual Emissions From Offroad Source Activity					89.42

2015 Emissions from a 5000 Ft Well

Construction Activity: D.1 Well Completion

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Accumulator Generator	1.0	8.0	24.00	100	8.00
Filter Skid (Pump)	1.0	2.0	3.00	90	.22
Acid Pump #1 (Hydraulic Oil Pump)	1.0	1.0	22.00	175	.85
Acid Pump #2 (Acid Fluid Pumping)	1.0	1.0	22.00	765	2.17
Generator for Doghouse for WO Rig	1.0	8.0	24.00	70	5.60
3 Light Plants for WO Rig	3.0	8.0	12.00	20	2.31
Diesel Engine for COROD or Other	1.0	1.0	22.00	450	1.67
Portable Den. Mud Separator	1.0	8.0	22.00	420	9.30
Rotary Table or Top Drive	1.0	8.0	22.00	135	11.26
Diesel Engine for Hoist	1.0	8.0	22.00	455	13.48
Diesel Engine for Hoist	1.0	8.0	22.00	442	13.09
Diesel Engine for Mud Pump	1.0	8.0	22.00	424	12.56
Annual Emissions From Offroad Source Activity (Lb/Year)					80.51

2015 Emissions from a 5000 Ft. Well

Construction Activity: E.1 Well Flowline

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Side Boom D4/Crawler	1.0	3.0	10.00	520	.92
Backhoe	1.0	3.0	10.00	95	.98
Pipe Fitting or Welders	1.0	3.0	10.00	40	.48
Hydrotest Pump	1.0	1.0	1.00	.08	.01
Forklift	1.0	3.0	10.00	125	.56
Other Equipment/Bending Machine	1.0	3.0	10.00	80	1.12
Annual Emissions From Offroad Source Activity					4.07

2015 Emissions from a 5000 Ft. Well

Construction Activity: F.1 Pump Unit

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Power Generator	1.0	2.0	8.00	10	.06
Backhoe	1.0	2.0	4.00	80	.22
Welder	1.0	2.0	8.00	25	.16
Annual Emissions From Offroad Source Activity					.44

2015 Emissions from a 5000 Ft. Well

Construction Activity: G.1 Electrical

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Line Truck	1.0	4.0	10.00	250	1.73
Bucket Truck	1.0	4.0	10.00	250	1.73
Electrical Service Truck	1.0	4.0	1.00	300	.15
Power Generators	1.0	4.0	1.00	10	.02
Back-Hoe	1.0	1.0	10.00	650	.80
Annual Emissions From Offroad Source Activity					4.43

2029/2035 Emissions from a 5000 ft. Well

Construction Activity: A1. Land Preparation

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Water Truck	1.0	7.0	8.48	400	.58
Loader	1.0	4.0	2.5	100	.04
35 Yard Dump Truck	1.0	2 .0	1.00	400	.02
Grader	1.0	4.0	2.5	175	.15
Skip & Scrap (Backhoe)	1.0	1.0	1.0	100	.00
Big Scrapper	1.0	2.0	2.5	362	.11
Dozer (D9R)	1.0	1.0	1.0	255	.03
Low Bed Truck/Trailer	1.0	2.0	.5	400	.01
Dump Truck 10 Wheels	1.0	1.0	.5	400	.00
Backhoe	1.0	2.0	.54	100	.00
Loader	1.0	3.0	2.5	100	.03
Loader	1.0	2.0	1.0	100	.01
Escavator (Backoe/tracks)	1.0	1.0	1.0	163	.01
Dozer (D8T)	1.0	1.0	1.0	255	.03
End Dump Truck & Trailer	1.0	1.0	.50	400	.00
Grader	1.0	1.0	.50	175	.01
Annual Emissions From Offroad Source Activity (Lb/Year)					1.03

2029/2035 Emissions from a 5000 Ft. Well

Construction Activity: B.1 Drilling Survey

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Rig-Truck Mounted	1.0	1.0	12.00	100	.58
Cement Truck-Cement Mousehole	1.0	1.0	12.00	400	.12
Annual Emissions From Offroad Source Activity (Lb/Year)					.70

2029/2035 Emission from a 5000 Ft. Well

Construction Activity: C.1 Well Drilling

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Crane	1.0	2.0	8.00	230	.19
Port Light Stands	5.0	9.0	12.00	20	.60
Portable Gen. Hydraulic Power	1.0	9.0	22.00	80	.86
Portable Gen. DSM/Trailers	2.0	9.0	24.00	100	2.35
Portable Gen. Mud Separator	1.0	8.0	22.00	420	1.37
Rotary Table or Top Drive	1.0	8.0	22.00	135	.74
Diesel Engine For Hoist	1.0	8.0	22.00	455	4.11
Diesel Engine For Hoist	1.0	8.0	22.00	442	3.99
Diesel Engine for Mud Pump	1.0	8.0	22.00	424	3.83
Annual Emissions From Offroad Source Activity (Lb/Year)					18.04

2029/2035 Emissions from a 5000 Ft Well

Construction Activity: D.1 Well Completion

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Accumulator Generator	1.0	8.0	24.00	100	1.04
Filter Skid (Pump)	1.0	2.0	3.00	90	.03
Acid Pump #1 (Hydraulic Oil Pump)	1.0	1.0	22.00	175	.12
Acid Pump #2 (Acid Fluid Pumping)	1.0	1.0	22.00	765	1.01
Generator for Doghouse for WO Rig	1.0	8.0	24.00	70	.73
3 Light Plants for WO Rig	3.0	8.0	12.00	20	.32
Diesel Engine for COROD or Other	1.0	1.0	22.00	450	.51
Portable Den. Mud Separator	1.0	8.0	22.00	420	1.37
Rotary Table or Top Drive	1.0	8.0	22.00	135	.74
Diesel Engine for Hoist	1.0	8.0	22.00	455	4.11
Diesel Engine for Hoist	1.0	8.0	22.00	442	3.99
Diesel Engine for Mud Pump	1.0	8.0	22.00	424	3.83
Annual Emissions From Offroad Source Activity (Lb/Year)					17.80

2029/2035 Emissions from a 5000 Ft. Well

Construction Activity: E.1 Well Flowline

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Side Boom D4/Crawler	1.0	3.0	10.00	520	.15
Backhoe	1.0	3.0	10.00	95	.12
Pipe Fitting or Welders	1.0	3.0	10.00	40	.07
Hydrotest Pump	1.0	1.0	1.00	.08	.00
Forklift	1.0	3.0	10.00	125	.08
Other Equipment/Bending Machine	1.0	3.0	10.00	80	.31
Annual Emissions From Offroad Source Activity					.73

2029/2035 Emissions from a 5000 Ft. Well

Construction Activity: F.1 Pump Unit

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Power Generator	1.0	2.0	8.00	10	.01
Backhoe	1.0	2.0	4.00	80	.03
Welder	1.0	2.0	8.00	25	.02
Annual Emissions From Offroad Source Activity					.06

2029/2035 Emissions from a 5000 Ft. Well Construction Activity: G.1 Electrical

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Line Truck	\1.0	4.0	10.00	250	.20
Bucket Truck	1.0	4.0	10.00	250	.20
Electrical Service Truck	1.0	4.0	1.00	300	.02
Power Generators	1.0	4.0	1.00	10	.00
Back-Hoe	1.0	1.0	10.00	650	.19
Annual Emissions From Offroad Source Activity					.61

2015 Emissions from a 10,000' Well
Construction Activity: A1. Land Preparation

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Water Truck	1.0	7.0	8.48	400	3.46
Loader	1.0	4.0	2.50	100	0.34
35 Yard Dump Truck	1.0	2.0	1.00	400	0.12
Grader	1.0	4.0	2.50	175	0.77
Skip & Scrap (Backhoe)	1.0	1.0	1.00	100	0.03
Big Scrapper	1.0	2.0	2.50	362	0.47
Dozer (D9R)	1.0	1.0	1.00	255	0.08
Low Bed Truck/Trailer	1.0	2.0	0.50	400	0.06
Dump Truck 10 Wheels	1.0	1.0	0.50	400	0.03
Backhoe	1.0	2.0	0.54	100	0.04
Loader	1.0	3.0	2.50	100	0.26
Loader	1.0	2.0	1.00	100	0.07
Escavator (Backoe/tracks)	1.0	1.0	1.00	163	0.03
Dozer (D8T)	1.0	1.0	1.00	255	0.08
End Dump Truck & Trailer	1.0	1.0	0.50	400	0.03
Grader	1.0	1.0	0.50	175	0.04
Annual Emissions From Offroad Source Activity (Lb/Year)					5.91

2015 Emissions from a 10,000 Ft. Well

Construction Activity: B.1 Drilling Survey

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Rig	1.0	1.0	12.00	100	0.58
Cement Truck	1.0	1.0	12.00	400	0.70
Annual Emissions From Offroad Source Activity (Lb/Year)					1.28

2010 Emission from a 10,000 Ft. Well

Construction Activity: C.1 Well Drilling

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Crane	1.0	2.0	8.00	230	0.81
Port Light Stands	5.0	24.0	12.00	20	11.55
Portable Gen. Hydraulic Power	1.0	24.0	22.00	80	17.59
Portable Gen. DSM/Trailers	2.0	24.0	24.00	100	47.97
Portable Gen. Mud Separator	1.0	23.0	22.00	420	26.75
Rotary Table or Top Drive	1.0	23.0	22.00	144	34.52
Diesel Engine For Hoist	1.0	23.0	22.00	996	88.93
Diesel Engine For Hoist	1.0	23.0	22.00	981	87.59
Diesel Engine for Mud Pump	1.0	23.0	22.00	1145	102.23
Annual Emissions From Offroad Source Activity (Lb/Year)					417.94

2015 Emissions from a 10,000 Ft Well

Construction Activity: D.1 Well Completion

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Accumulator Generator	1.0	13.0	24.00	100	12.99
Filter Skid (Pump)	1.0	2.0	3.00	90	0.22
Acid Pump #1 (Hydraulic Oil Pump)	1.0	1.0	22.00	175	0.85
Acid Pump #2 (Acid Fluid Pumping)	1.0	1.0	22.00	765	2.017
Generator for Doghouse for WO Rig	1.0	13.0	24.00	70	9.10
3 Light Plants for WO Rig	3.0	13.0	12.00	20	3.75
Diesel Engine for COROD or Other	1.0	1.0	22.00	450	1.67
Portable Den. Mud Separator	1.0	13.0	22.00	420	15.12
Rotary Table or Top Drive	1.0	13.0	22.00	135	18.29
Diesel Engine for Hoist	1.0	13.0	22.00	455	21.90
Diesel Engine for Hoist	1.0	13.0	22.00	442	21.28
Diesel Engine for Mud Pump	1.0	13.0	22.00	424	20.41
Annual Emissions From Offroad Source Activity (Lb/Year)					127.75

2015 Emissions from a 10,000 Ft. Well Construction Activity: E.1 Well Flowline

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Side Boom D4/Crawler	1.0	3.0	10.00	520	0.92
Backhoe	1.0	3.0	10.00	95	0.98
Pipe Fitting or Welders	1.0	3.0	10.00	40	0.48
Hydrotest Pump	1.0	1.0	1.00	20	0.01
Forklift	1.0	3.0	10.00	125	0.56
Other Equipment/Bending Machine	1.0	3.0	10.00	80	1.12
Annual Emissions From Offroad Source Activity (Lb/Year)					4.07

2015 Emissions from a 10,000 Ft. Well

Construction Activity: F.1 Pump Unit

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Power Generator	1.0	2.0	8.00	10	0.06
Backhoe	1.0	2.0	4.00	80	0.22
Welder	1.0	2.0	8.00	25	0.16
Annual Emissions From Offroad Source Activity (Lb/Year)					0.44

2015 Emissions from a 10,000 Ft. Well

Construction Activity: G.1 Electrical

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Line Truck	1.0	4.0	10.00	250	1.73
Bucket Truck	1.0	4.0	10.00	250	1.73
Electrical Service Truck	1.0	4.0	1.00	300	0.15
Power Generators	1.0	4.0	1.00	10	0.02
Back-Hoe	1.0	1.0	10.00	650	0.80
Annual Emissions From Offroad Source Activity (Lb/Year)					4.43

2029/2035 Emissions from a 10,000 Ft. Well					
Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Water Truck	1.0	7.0	8.48	400	0.58
Loader	1.0	4.0	2.50	100	0.04
35 Yard Dump Truck	1.0	2.0	1.00	400	0.02
Grader	1.0	4.0	2.50	175	0.15
Skip & Scrap (Backhoe)	1.0	1.0	1.00	100	0.00
Big Scrapper	1.0	2.0	2.50	362	0.11
Dozer (D9R)	1.0	1.0	1.00	255	0.03
Low Bed Truck/Trailer	1.0	2.0	0.50	400	0.01
Dump Truck 10 Wheels	1.0	1.0	0.50	400	0.00
Backhoe	1.0	2.0	0.54	100	0.00
Loader	1.0	3.0	2.50	100	0.03
Loader	1.0	2.0	1.00	100	0.01
Escavator (Backoe/tracks)	1.0	1.0	1.00	163	0.01
Dozer (D8T)	1.0	1.0	1.00	255	0.03
End Dump Truck & Trailer	1.0	1.0	0.50	400	0.00
Grader	1.0	1.0	0.50	175	0.01
Annual Emissions From Offroad Source Activity (Lb/Year)					1.03
Construction Activity: A.1 Land Preparation					

2029/2035 Emissions from a 10,000 Ft. Well Construction Activity: B.1 Drilling Survey

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Rig	1.0	1.0	12.00	100	0.58
Cement Truck	1.0	1.0	12.00	400	0.12
Annual Emissions From Offroad Source Activity (Lb/Year)					0.70

2029/2035 Emission from a 10,000 Ft. Well

Construction Activity: C.1 Well Drilling

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Crane	1.0	2.00	8.00	230	0.19
Port Light Stands	5.0	24.0	12.00	20	1.61
Portable Gen. Hydraulic Power	1.0	24.0	22.00	80	2.30
Portable Gen. DSM/Trailers	2.0	24.0	24.00	100	6.27
Portable Gen. Mud Separator	1.0	23.0	22.00	420	3.94
Rotary Table or Top Drive	1.0	23.0	22.00	144	2.28
Diesel Engine For Hoist	1.0	23.0	22.00	996	37.47
Diesel Engine For Hoist	1.0	23.0	22.00	981	36.90
Diesel Engine for Mud Pump	1.0	23.0	22.00	1145	43.07
Annual Emissions From Offroad Source Activity (Lb/Year)					134.03

2029/2035 Emissions from a 10,000 Ft Well

Construction Activity: D.1 Well Completion

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Accumulator Generator	1.0	13.0	24.00	100	1.70
Filter Skid (Pump)	1.0	2.0	3.00	90	0.03
Acid Pump #1 (Hydraulic Oil Pump)	1.0	1.0	22.00	175	0.12
Acid Pump #2 (Acid Fluid Pumping)	1.0	1.0	22.00	765	1.01
Generator for Doghouse for WO Rig	1.0	13.0	24.00	70	1.19
3 Light Plants for WO Rig	3.0	13.0	12.00	20	0.52
Diesel Engine for COROD or Other	1.0	1.0	22.00	450	0.51
Portable Den. Mud Separator	1.0	13.0	22.00	420	2.22
Rotary Table or Top Drive	1.0	13.0	22.00	135	1.21
Diesel Engine for Hoist	1.0	13.0	22.00	455	6.67
Diesel Engine for Hoist	1.0	13.0	22.00	442	6.48
Diesel Engine for Mud Pump	1.0	13.0	22.00	424	6.22
Annual Emissions From Offroad Source Activity (Lb/Year)					27.88

2029/2035 Emissions from a 10,000 Ft. Well

Construction Activity: E.1 Well Flowline

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Side Boom D4/Crawler	1.0	3.0	10.00	520	0.15
Backhoe	1.0	3.0	10.00	95	0.12
Pipe Fitting or Welders	1.0	3.0	10.00	40	0.07
Hydrotest Pump	1.0	1.0	1.00	20	0.00
Forklift	1.0	3.0	10.00	125	0.08
Other Equipment/Bending Machine	1.0	3.0	10.00	80	0.31
Annual Emissions From Offroad Source Activity (Lb/Year)					0.73

2029/2035 Emissions from a 10,000 Ft. Well Construction Activity: F.1 Pump Unit

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Power Generator	1.0	2.0	8.00	10	0.01
Backhoe	1.0	2.0	4.00	80	0.03
Welder	1.0	2.0	8.00	25	0.02
Annual Emissions From Offroad Source Activity (Lb/Year)					0.06

2029/2035 Emissions from a 10,000 Ft. Well

Construction Activity: G.1 Electrical

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Line Truck	1.0	4.0	10.00	250	0.20
Bucket Truck	1.0	4.0	10.00	250	0.20
Electrical Service Truck	1.0	4.0	1.00	300	0.02
Power Generators	1.0	4.0	1.00	10	0.00
Back-Hoe	1.0	1.0	10.00	650	0.19
Annual Emissions From Offroad Source Activity (Lb/Year)					0.61

2017 Emissions from a 15,000 ft. Well

Construction Activity: A1. Land Preparation

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Water Truck	1.0	7.0	8.48	400	2.72
Loader	1.0	4.0	2.50	100	0.29
35 Yard Dump Truck	1.0	2.0	1.00	400	0.09
Grader	1.0	4.0	2.5	175	0.68
Skip & Scrap (Backhoe)	1.0	1.0	1.0	100	0.03
Big Scrapper	1.0	2.0	2.5	362	0.41
Dozer (D9R)	1.0	1.0	1.0	255	0.08
Low Bed Truck/Trailer	1.0	2.0	.50	400	0.05
Dump Truck 10 Wheels	1.0	1.0	.50	400	0.02
Backhoe	1.0	2.0	.54	100	0.03
Loader	1.0	3.0	2.50	100	0.22
Loader	1.0	2.0	1.00	100	0.06
Escavator (Backoe/tracks)	1.0	1.0	1.00	163	0.02
Dozer (D8T)	1.0	1.0	1.00	255	0.08
End Dump Truck & Trailer	1.0	1.0	.50	400	0.02
Grader	1.0	1.0	.50	175	0.03
Annual Emissions From Offroad Source Activity (Lb/Year)					4.83

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Rig	1.0	1.0	12.00	100	0.58
Cement Truck	1.0	1.0	12.00	400	0.55
Annual Emissions From Offroad Source Activity (Lb/Year)					1.13

2017 Emission from a 15,000 Ft. Well

Construction Activity: C.1 Well Drilling

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Crane	1.0	2.0	8.00	230	0.69
Port Light Stands	5.0	66.0	12.00	20	28.59
Portable Gen. Hydraulic Power	1.0	66.0	22.00	80	41.17
Portable Gen. DSM/Trailers	2.0	66.0	24.00	100	112.28
Portable Gen. Mud Separator	1.0	65.0	22.00	420	68.79
Rotary Table or Top Drive	1.0	65.0	22.00	158	86.28
Diesel Engine For Hoist	1.0	65.0	22.00	1094	276.05
Diesel Engine For Hoist	1.0	65.0	22.00	962	242.74
Diesel Engine for Mud Pump	1.0	65.0	22.00	1898	478.93
Annual Emissions From Offroad Source Activity (Lb/Year)					1335.52

2017 Emissions from a 15,000 Ft Well

Construction Activity: D.1 Well Completion

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Accumulator Generator	1.0	17.0	24.00	100	14.46
Filter Skid (Pump)	1.0	2.0	3.00	90	0.19
Acid Pump #1 (Hydraulic Oil Pump)	1.0	1.0	22.00	175	0.72
Acid Pump #2 (Acid Fluid Pumping)	1.0	1.0	22.00	765	1.45
Generator for Doghouse for WO Rig	1.0	17.0	24.00	70	10.12
3 Light Plants for WO Rig	3.0	17.0	12.00	20	4.42
Diesel Engine for COROD or Other	1.0	1.0	22.00	450	1.49
Portable Den. Mud Separator	1.0	17.0	22.00	420	17.99
Rotary Table or Top Drive	1.0	17.0	22.00	144	20.57
Diesel Engine for Hoist	1.0	17.0	22.00	996	65.73
Diesel Engine for Hoist	1.0	17.0	22.00	981	64.74
Diesel Engine for Mud Pump	1.0	17.0	22.00	1145	75.56
Annual Emissions From Offroad Source Activity (Lb/Year)					277.44

2017 Emissions from a 15,000 Ft. Well

Construction Activity: E.1 Well Flowline

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Side Boom D4/Crawler	1.0	3.0	10.00	520	0.79
Backhoe	1.0	3.0	10.00	95	0.84
Pipe Fitting or Welders	1.0	3.0	10.00	40	0.43
Hydrotest Pump	1.0	1.0	1.00	20	0.01
Forklift	1.0	3.0	10.00	125	0.49
Other Equipment/Bending Machine	1.0	3.0	10.00	80	1.04
Annual Emissions From Offroad Source Activity (Lb/Year)					3.60

2017 Emissions from a 15,000 Ft. Well Construction Activity: F.1 Pump Unit

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Power Generator	1.0	2.0	8.00	10	0.06
Backhoe	1.0	2.0	4.00	80	0.19
Welder	1.0	2.0	8.00	25	0.14
Annual Emissions From Offroad Source Activity (Lb/Year)					0.39

2017 Emissions from a 15,000 Ft. Well

Construction Activity: G.1 Electrical

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Line Truck	1.0	4.0	10.00	250	1.50
Bucket Truck	1.0	4.0	10.00	250	1.50
Electrical Service Truck	1.0	4.0	1.00	300	0.14
Power Generators	1.0	4.0	1.00	10	0.01
Back-Hoe	1.0	1.0	10.00	650	0.74
Annual Emissions From Offroad Source Activity (Lb/Year)					3.89

Appendix C
Emission Calculations

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KERN EIR
CRITERIA POLLUTANTS
Updated May 7, 2015

100	PPMV H2S
1000	Btu/ft3

SRC ID			NOx	VOC	CO	SO2	PM10	PM2.5	H2S
FHC01	1-Hour	lb/hr		0.013					2.66E-06
FHC01	Daily	lb/day		0.300					6.38E-05
FHC01	Annual	tpy		0.055					1.16E-05
FLR01	1-Hour	lb/hr	1.330	0.027	0.680	0.165	0.076	0.076	1.79E-03
FLR01	Daily	lb/day	31.920	0.648	16.320	3.966	1.824	1.824	4.30E-02
FLR01	Annual	tpy	5.825	0.118	2.978	0.724	0.333	0.333	7.85E-03
SMP01	1-Hour	lb/hr		0.263					5.58E-05
SMP01	Daily	lb/day		6.300					1.34E-03
SMP01	Annual	tpy		1.150					2.44E-04
LDR01	1-Hour	lb/hr		0.732					1.56E-04
LDR01	Daily	lb/day		17.571					3.73E-03
LDR01	Annual	tpy		3.207					6.81E-04
TNK03	1-Hour	lb/hr		0.869					1.85E-04
TNK03	Daily	lb/day		20.850					4.43E-03
TNK03	Annual	tpy		3.805					8.09E-04
TNK02	1-Hour	lb/hr		0.869					1.85E-04
TNK02	Daily	lb/day		20.850					4.43E-03
TNK02	Annual	tpy		3.805					8.09E-04
TNK01	1-Hour	lb/hr		0.686					1.46E-04
TNK01	Daily	lb/day		16.470					3.50E-03
TNK01	Annual	tpy		3.006					6.39E-04
PHT01	1-Hour	lb/hr	0.088	0.044	0.672	0.132	0.061	0.061	1.43E-03
PHT01	Daily	lb/day	2.112	1.056	16.128	3.173	1.459	1.459	3.44E-02
PHT01	Annual	tpy	0.385	0.193	2.943	0.579	0.266	0.266	6.28E-03
SGR01	1-Hour	lb/hr	0.595	0.468	7.140	1.405	0.646	0.646	1.52E-02
SGR01	Daily	lb/day	14.280	11.220	171.360	33.715	15.504	15.504	3.66E-01
SGR01	Annual	tpy	2.606	2.048	31.273	6.153	2.829	2.829	6.67E-02
ICE01	1-Hour	lb/hr	0.259	0.322	1.126	0.140	0.044	0.044	1.52E-03
ICE01	Daily	lb/day	6.217	7.724	27.032	3.362	1.058	1.058	3.64E-02
ICE01	Annual	tpy	1.135	1.410	4.933	0.613	0.193	0.193	6.65E-03
DRL01	1-Hour	lb/hr					2.033	2.033	
DRL01	Daily	lb/day					24.391	24.391	
DRL01	Annual	tpy					0.009	0.009	
COG01	1-Hour	lb/hr	1.692	0.592	23.123	4.660	1.861	1.861	5.05E-02
COG01	Daily	lb/day	40.606	14.212	554.946	111.849	44.666	44.666	1.21E+00
COG01	Annual	tpy	7.411	2.594	101.278	20.412	8.152	8.152	2.21E-01
SMP02	1-Hour	lb/hr		0.011					2.34E-06
SMP02	Daily	lb/day		0.265					5.62E-05
SMP02	Annual	tpy		0.048					1.03E-05
BLR01	1-Hour	lb/hr	0.110	0.055	0.840	0.165	0.076	0.076	1.79E-03
BLR01	Daily	lb/day	2.640	1.320	20.160	3.966	1.824	1.824	4.30E-02
BLR01	Annual	tpy	0.482	0.241	3.679	0.724	0.333	0.333	7.85E-03
TEOR	1-Hour	lb/hr		0.037					7.79E-06
TEOR	Daily	lb/day		0.880					1.87E-04
TEOR	Annual	tpy		0.161					3.41E-05
FLR02	1-Hour	lb/hr	13.300	0.270	6.800	1.653	0.760	0.760	1.79E-02
FLR02	Daily	lb/day	319.200	6.480	163.200	39.665	18.240	18.240	4.30E-01
FLR02	Annual	tpy	58.254	1.183	29.784	7.239	3.329	3.329	7.85E-02

Notes
1. Only change yellow highlighted cells
2. Do not change toxic summary or toxic source sheets

KERN EIR

SRC ID	0	0	CAS	NAME		lb/yr	lb/hr	
FHC01	0	0	95636	"1,2,4 Trimethylbenzene"	1	0.01	0.00	1
FHC01	0	0	71432	Benzene	1	0.32	0.00	1
FHC01	0	0	110827	Cyclohexane	1	0.02	0.00	1
FHC01	0	0	100414	Ethylbenzene	1	0.10	0.00	1
FHC01	0	0	110543	n-Hexane	1	2.38	0.00	1
FHC01	0	0	108883	Toluene	1	0.36	0.00	1
FHC01	0	0	1330207	Xylenes	1	0.19	0.00	1
FHC01	0	0	7783064	Hydrogen sulfide	1	0.02	0.00	1
FLR01	0	0	75070	Acetaldehyde	1	3.77	0.00	1
FLR01	0	0	107028	Acrolein	1	0.88	0.00	1
FLR01	0	0	71432	Benzene	1	13.93	0.00	1
FLR01	0	0	110827	Cyclohexane	1	0.00	0.00	1
FLR01	0	0	100414	Ethylbenzene	1	126.49	0.01	1
FLR01	0	0	50000	Formaldehyde	1	102.40	0.01	1
FLR01	0	0	110543	n-Hexane	1	2.54	0.00	1
FLR01	0	0	7783064	Hydrogen sulfide	1	15.70	0.00	1
FLR01	0	0	91203	Naphthalene	1	0.96	0.00	1
FLR01	0	0	1151	PAH's	1	1.23	0.00	1
FLR01	0	0	115071	Propylene	1	213.74	0.02	1
FLR01	0	0	108883	Toluene	1	5.08	0.00	1
FLR01	0	0	1330207	Xylenes	1	2.54	0.00	1
SMP01	0	0	95636	"1,2,4 Trimethylbenzene"	1	0.23	0.00	1
SMP01	0	0	71432	Benzene	1	6.78	0.00	1
SMP01	0	0	110827	Cyclohexane	1	0.33	0.00	1
SMP01	0	0	100414	Ethylbenzene	1	2.16	0.00	1
SMP01	0	0	110543	n-Hexane	1	50.00	0.01	1
SMP01	0	0	108883	Toluene	1	7.60	0.00	1
SMP01	0	0	1330207	Xylenes	1	4.01	0.00	1
SMP01	0	0	7783064	Hydrogen sulfide	1	0.49	0.00	1
LDR01	0	0	95636	"1,2,4 Trimethylbenzene"	1	0.63	0.00	1
LDR01	0	0	71432	Benzene	1	18.92	0.00	1
LDR01	0	0	110827	Cyclohexane	1	0.92	0.00	1
LDR01	0	0	100414	Ethylbenzene	1	6.02	0.00	1
LDR01	0	0	110543	n-Hexane	1	139.46	0.02	1
LDR01	0	0	108883	Toluene	1	21.20	0.00	1
LDR01	0	0	1330207	Xylenes	1	11.18	0.00	1
LDR01	0	0	7783064	Hydrogen sulfide	1	1.36	0.00	1
TNK03	0	0	95636	"1,2,4 Trimethylbenzene"	1	0.75	0.00	1
TNK03	0	0	71432	Benzene	1	22.45	0.00	1
TNK03	0	0	110827	Cyclohexane	1	1.10	0.00	1
TNK03	0	0	100414	Ethylbenzene	1	7.15	0.00	1
TNK03	0	0	110543	n-Hexane	1	165.48	0.02	1
TNK03	0	0	108883	Toluene	1	25.16	0.00	1
TNK03	0	0	1330207	Xylenes	1	13.26	0.00	1
TNK03	0	0	7783064	Hydrogen sulfide	1	1.62	0.00	1
TNK02	0	0	95636	"1,2,4 Trimethylbenzene"	1	0.75	0.00	1
TNK02	0	0	71432	Benzene	1	22.45	0.00	1
TNK02	0	0	110827	Cyclohexane	1	1.10	0.00	1
TNK02	0	0	100414	Ethylbenzene	1	7.15	0.00	1
TNK02	0	0	110543	n-Hexane	1	165.48	0.02	1
TNK02	0	0	108883	Toluene	1	25.16	0.00	1
TNK02	0	0	1330207	Xylenes	1	13.26	0.00	1
TNK02	0	0	7783064	Hydrogen sulfide	1	1.62	0.00	1
TNK01	0	0	95636	"1,2,4 Trimethylbenzene"	1	0.60	0.00	1
TNK01	0	0	71432	Benzene	1	17.73	0.00	1
TNK01	0	0	110827	Cyclohexane	1	0.87	0.00	1
TNK01	0	0	100414	Ethylbenzene	1	5.64	0.00	1
TNK01	0	0	110543	n-Hexane	1	130.72	0.02	1
TNK01	0	0	108883	Toluene	1	19.87	0.00	1
TNK01	0	0	1330207	Xylenes	1	10.48	0.00	1
TNK01	0	0	7783064	Hydrogen sulfide	1	1.28	0.00	1
PHT01	0	0	83329	Acenaphthene	1	0.00	0.00	1
PHT01	0	0	208968	Acenaphthylene	1	0.01	0.00	1

PHT01	0	0	75070	Acetaldehyde	1	1.17	0.00	1
PHT01	0	0	107028	Acrolein	1	0.20	0.00	1
PHT01	0	0	120127	Anthracene	1	0.00	0.00	1
PHT01	0	0	56553	Benz(a)anthracene	1	0.00	0.00	1
PHT01	0	0	71432	Benzene	1	1.71	0.00	1
PHT01	0	0	50328	Benzo(a)pyrene	1	0.00	0.00	1
PHT01	0	0	205992	Benzo(b)fluoranthene	1	0.00	0.00	1
PHT01	0	0	191242	"Benzo(g,h,i)perylene"	1	0.00	0.00	1
PHT01	0	0	207089	Benzo(k)fluoranthene	1	0.00	0.00	1
PHT01	0	0	218019	Chrysene	1	0.00	0.00	1
PHT01	0	0	53703	"Dibenz(a,h)anthracene"	1	0.00	0.00	1
PHT01	0	0	206440	Fluoranthene	1	0.00	0.00	1
PHT01	0	0	86737	Fluorene	1	0.12	0.00	1
PHT01	0	0	50000	Formaldehyde	1	6.23	0.00	1
PHT01	0	0	7783064	Hydrogen sulfide	1	12.56	0.00	1
PHT01	0	0	193395	"Indeno(1,2,3-cd)pyrene"	1	0.00	0.00	1
PHT01	0	0	91203	Naphthalene	1	0.43	0.00	1
PHT01	0	0	85018	Phenanthrene	1	0.03	0.00	1
PHT01	0	0	108952	Phenol	1	0.15	0.00	1
PHT01	0	0	115071	Propylene	1	0.97	0.00	1
PHT01	0	0	129000	Pyrene	1	0.00	0.00	1
PHT01	0	0	108883	Toluene	1	2.12	0.00	1
PHT01	0	0	1330207	Xylenes	1	2.45	0.00	1
SGR01	0	0	83329	Acenaphthene	1	0.00	0.00	1
SGR01	0	0	208968	Acenaphthylene	1	0.01	0.00	1
SGR01	0	0	75070	Acetaldehyde	1	19.88	0.00	1
SGR01	0	0	107028	Acrolein	1	13.55	0.00	1
SGR01	0	0	120127	Anthracene	1	0.00	0.00	1
SGR01	0	0	56553	Benz(a)anthracene	1	0.00	0.00	1
SGR01	0	0	71432	Benzene	1	4.62	0.00	1
SGR01	0	0	50328	Benzo(a)pyrene	1	0.00	0.00	1
SGR01	0	0	205992	Benzo(b)fluoranthene	1	0.00	0.00	1
SGR01	0	0	191242	"Benzo(g,h,i)perylene"	1	0.00	0.00	1
SGR01	0	0	207089	Benzo(k)fluoranthene	1	0.00	0.00	1
SGR01	0	0	218019	Chrysene	1	0.00	0.00	1
SGR01	0	0	53703	"Dibenz(a,h)anthracene"	1	0.00	0.00	1
SGR01	0	0	100414	Ethylbenzene	1	13.85	0.00	1
SGR01	0	0	206440	Fluoranthene	1	0.01	0.00	1
SGR01	0	0	86737	Fluorene	1	0.01	0.00	1
SGR01	0	0	50000	Formaldehyde	1	52.20	0.01	1
SGR01	0	0	7783064	Hydrogen sulfide	1	133.42	0.02	1
SGR01	0	0	193395	"Indeno(1,2,3-cd)pyrene"	1	0.00	0.00	1
SGR01	0	0	91203	Naphthalene	1	0.41	0.00	1
SGR01	0	0	85018	Phenanthrene	1	0.02	0.00	1
SGR01	0	0	115071	Propylene	1	469.10	0.05	1
SGR01	0	0	129000	Pyrene	1	0.01	0.00	1
SGR01	0	0	108883	Toluene	1	22.93	0.00	1
SGR01	0	0	1330207	Xylenes	1	30.01	0.00	1
ICE01	0	0	71432	Benzene	1	126.21	0.01	1
ICE01	0	0	50000	Formaldehyde	1	3118.12	0.36	1
ICE01	0	0	115071	Propylene	1	1187.86	0.14	1
ICE01	0	0	108883	Toluene	1	57.17	0.01	1
ICE01	0	0	1330207	Xylenes	1	28.95	0.00	1
ICE01	0	0	7783064	Hydrogen sulfide	1	13.30	0.00	1
DRL01	0	0	9901.00	Diesel Particulate Matter	1	18.70	2.03	1
COG01	0	0	71432	Benzene	1	36.07	0.00	1
COG01	0	0	7783064	Hydrogen sulfide	1	442.64	0.05	1
COG01	0	0	91203	Naphthalene	1	14.30	0.00	1
COG01	0	0	1151	PAH's	1	0.63	0.00	1
COG01	0	0	50000	Formaldehyde	1	454.54	0.05	1
SMP02	0	0	95636	"1,2,4 Trimethylbenzene"	1	0.01	0.00	1
SMP02	0	0	71432	Benzene	1	0.28	0.00	1
SMP02	0	0	110827	Cyclohexane	1	0.01	0.00	1
SMP02	0	0	100414	Ethylbenzene	1	0.09	0.00	1
SMP02	0	0	110543	n-Hexane	1	2.10	0.00	1
SMP02	0	0	108883	Toluene	1	0.32	0.00	1

SMP02	0	0	1330207	Xylenes	1	0.17	0.00	1
SMP02	0	0	7783064	Hydrogen sulfide	1	0.02	0.00	1
BLR01	0	0	83329	Acenaphthene	1	0.00	0.00	1
BLR01	0	0	208968	Acenaphthylene	1	0.00	0.00	1
BLR01	0	0	75070	Acetaldehyde	1	2.34	0.00	1
BLR01	0	0	107028	Acrolein	1	1.59	0.00	1
BLR01	0	0	120127	Anthracene	1	0.00	0.00	1
BLR01	0	0	56553	Benz(a)anthracene	1	0.00	0.00	1
BLR01	0	0	71432	Benzene	1	0.54	0.00	1
BLR01	0	0	50328	Benzo(a)pyrene	1	0.00	0.00	1
BLR01	0	0	205992	Benzo(b)fluoranthene	1	0.00	0.00	1
BLR01	0	0	191242	"Benzo(g,h,i)perylene"	1	0.00	0.00	1
BLR01	0	0	207089	Benzo(k)fluoranthene	1	0.00	0.00	1
BLR01	0	0	218019	Chrysene	1	0.00	0.00	1
BLR01	0	0	53703	"Dibenz(a,h)anthracene"	1	0.00	0.00	1
BLR01	0	0	100414	Ethylbenzene	1	1.63	0.00	1
BLR01	0	0	206440	Fluoranthene	1	0.00	0.00	1
BLR01	0	0	86737	Fluorene	1	0.00	0.00	1
BLR01	0	0	50000	Formaldehyde	1	6.14	0.00	1
BLR01	0	0	7783064	Hydrogen sulfide	1	15.70	0.00	1
BLR01	0	0	193395	"Indeno(1,2,3-cd)pyrene"	1	0.00	0.00	1
BLR01	0	0	91203	Naphthalene	1	0.05	0.00	1
BLR01	0	0	85018	Phenanthrene	1	0.00	0.00	1
BLR01	0	0	115071	Propylene	1	55.19	0.01	1
BLR01	0	0	129000	Pyrene	1	0.00	0.00	1
BLR01	0	0	108883	Toluene	1	2.70	0.00	1
BLR01	0	0	1330207	Xylenes	1	3.53	0.00	1
TEOR	0	0	95636	"1,2,4 Trimethylbenzene"	1	0.03	0.00	1
TEOR	0	0	71432	Benzene	1	0.95	0.00	1
TEOR	0	0	110827	Cyclohexane	1	0.05	0.00	1
TEOR	0	0	100414	Ethylbenzene	1	0.30	0.00	1
TEOR	0	0	110543	n-Hexane	1	6.98	0.00	1
TEOR	0	0	108883	Toluene	1	1.06	0.00	1
TEOR	0	0	1330207	Xylenes	1	0.56	0.00	1
TEOR	0	0	7783064	Hydrogen sulfide	1	0.07	0.00	1
FLR02	0	0	75070	Acetaldehyde	1	37.67	0.00	1
FLR02	0	0	107028	Acrolein	1	8.76	0.00	1
FLR02	0	0	71432	Benzene	1	139.28	0.02	1
FLR02	0	0	110827	Cyclohexane	1	0.00	0.00	1
FLR02	0	0	100414	Ethylbenzene	1	1264.94	0.14	1
FLR02	0	0	50000	Formaldehyde	1	1024.04	0.12	1
FLR02	0	0	110543	n-Hexane	1	25.40	0.00	1
FLR02	0	0	7783064	Hydrogen sulfide	1	15.70	0.00	1
FLR02	0	0	91203	Naphthalene	1	9.64	0.00	1
FLR02	0	0	1151	PAH's	1	12.26	0.00	1
FLR02	0	0	115071	Propylene	1	2137.44	0.24	1
FLR02	0	0	108883	Toluene	1	50.81	0.01	1
FLR02	0	0	1330207	Xylenes	1	25.40	0.00	1

Fugitive Hydrocarbons

VOC and H2S Emissions Only

0.3 Daily VOC Emissions based on Mike Kelly Analysis, Feb 2015
SJV Rule 4409

100 H2S Concentration in VOCs
Per Client

16 MW VOCs
34 MW H2S

	lb/hr	lb/day	lb/yr	tpy
VOC	0.01	0.30	109.50	0.05
H2S	2.66E-06	6.38E-05	2.33E-02	1.16E-05

Flare

10	MMBtu/hr
1000	scf/MMBtu
100	ppmv H2S[1]
0.98	H2S Destruction Efficiency
0.01	MMCF/hr
87.6	MMCF/yr

Flare					Field Gas Fuel			
FLR01	PPMV	lb/MMCF[2]	lb/MMBtu[3]	MW	Lb/hr	lb/day	lb/yr	tpy
NOx	15		0.133	46	1.330	31.920	11650.800	5.825
VOC		5.5	0.0027	16	0.027	0.648	236.520	0.118
CO		68	0.068	28	0.680	16.320	5956.800	2.978
SOx	98			64	0.165	3.966	1447.766	0.724
PM10		7.6	0.0076		0.076	1.824	665.760	0.333
PM2.5		7.6	0.0076		0.076	1.824	665.760	0.333
H2S	2			34	0.002	0.043	15.696	0.008

[1]Per Client

[2]AP-42 Tables 13.5-1

[3]SJVAPCD Rule 4311 for NOx and VOC

SUMP

30	ft	Length of side
0.007	lb/day-ft2	VOC emissions[1]
100	ppmv	H2S Content in VOCs
16	MV VOC	
34	MW H2S	

	lb/hr	lb/day	lb/yr	tpy
VOC	0.26	6.30	2299.50	1.15
H2S	5.58E-05	1.34E-03	4.89E-01	2.44E-04

[1]SJVAPCD Rule 4402

Vacuum Truck

0.082	lb/bbl	BAAQMD
6000	gallons	Vacuum Truck Capacity
1.5	Trucks/day	
42	gallons/barrel	
100	ppmv H2s	
16	MW VOC	
34	MW H2S	

	lb/hr	lb/day	lb/yr	tpy
VOC	0.73	17.57	6413.57	3.21
H2S	1.56E-04	3.73E-03	1.36E+00	6.81E-04

Tank 3

1000	BBl
100	ppmv H2S
16	MW VOC
34	MW H2S

20.85 lb VOC/day TANKS Output

	lb/hr	lb/day	lb/yr	tpy
VOC	0.87	20.85	7610.25	3.81
H2S	1.85E-04	4.43E-03	1.62E+00	8.09E-04

Tank 2

1000	BBl
100	ppmv H2S
16	MW VOC
34	MW H2S

20.85	lb VOC/day	TANKS Output

	lb/hr	lb/day	lb/yr	tpy
VOC	0.87	20.85	7610.25	3.81
H2S	1.85E-04	4.43E-03	1.62E+00	8.09E-04

Tank 1

3000	BBl
100	ppmv H2S
16	MW VOC
34	MW H2S

16.47	lb VOC/day	TANKS Output

	lb/hr	lb/day	lb/yr	tpy
VOC	0.69	16.47	6011.55	3.01
H2S	1.46E-04	3.50E-03	1.28E+00	6.39E-04

Process Heater

8	MMBtu/hr
1000	scf/MMBtu
100	ppmv H2S[1]
0.98	H2S Destruction Efficiency
0.008	MMCF/hr
70.08	MMCF/yr

Process Heater					Field Gas Fuel			
PHT01	PPMV	lb/MMCF[2]	lb/MMBtu[3]	MW	Lb/hr	lb/day	lb/yr	tpy
NOx	9		0.011	46	0.088	2.112	770.880	0.385
VOC		5.5	0.0055	16	0.044	1.056	385.440	0.193
CO	400	84	0.084	28	0.672	16.128	5886.720	2.943
SOx	98			64	0.132	3.173	1158.213	0.579
PM10		7.6	0.0076		0.061	1.459	532.608	0.266
PM2.5		7.6	0.0076		0.061	1.459	532.608	0.266
H2S	2			34	0.001	0.034	12.557	0.006

[1]Per Client

[2]AP-42 Tables 1.4-1 & 1.4-2

[3]SJVAPCD Rule 4306, Table 1, Enhanced Option for NOx and CO

Steam Generator

85	MMBtu/hr
1000	scf/MMBtu
100	ppmv H2S[1]
0.98	H2S Destruction Efficiency
0.085	
744.6	

Steam Generator					Field Gas Fuel			
SGR01	PPMV	lb/MMCF[2]	lb/MMBtu[3]	MW	Lb/hr	lb/day	lb/yr	tpy
NOx	6		0.007	46	0.595	14.280	5212.200	2.606
VOC		5.5	0.0055	16	0.468	11.220	4095.300	2.048
CO	400	84	0.084	28	7.140	171.360	62546.400	31.273
SOx	98			64	1.405	33.715	12306.011	6.153
PM10		7.6	0.0076		0.646	15.504	5658.960	2.829
PM2.5		7.6	0.0076		0.646	15.504	5658.960	2.829
H2S	2			34	0.015	0.366	133.420	0.067

[1]Per Client

[2]AP-42 Tables 1.4-1 & 1.4-2

[3]SJVAPCD Rule 4306 for NOx and CO

IC ENGINE

1000	Bhp
1000	scf/MMBtu
8475	Btu/bhp-hr
100	ppmv H2S
0.98	H2S Destruction Efficiency
0.008475	MMCF/hr
74.241	
89383	ACF@850F/MMBtu
74.241	

Natural Gas Engine				Field Gas			
IC Engine	PPMV[1]	g/Bhp-hr[2]	MW	Lb/hr	lb/day	lb/yr	tpy
NOx	7		46	0.259	6.217	2269.371	1.135
VOC	25		16	0.322	7.724	2819.094	1.410
CO	50		28	1.126	27.032	9866.829	4.933
SOx	98		64	0.140	3.362	1226.982	0.613
PM10		0.02		0.044	1.058	386.252	0.193
PM2.5		0.02		0.044	1.058	386.252	0.193
H2S	2		34	0.002	0.036	13.303	0.007

[1]SJVAPCD Rule 4702 for NOx, CO and VOC (and Mike Kelly notes)

[2]AP-42, Tables 3.2-1 and 3.2-2

Diesel Emissions
Well Construction
10000 ft well
2015 Year

30	Years	
23	Drill Days	
561	lb/well	Mike Kelly Spreadsheet Feb 2015

lb/yr	tpy	lb/day	lb/hr
18.70	0.01	24.39	2.03

Cogen

33	MW	Field Gas Turbine
5	PPMV NOx	
0.281985	MMCF/hr	
8545	Btu/kw-hr	
1000	scf/MMBtu	
100	ppmv H2S[1]	
0.98	H2S Destruction Efficiency	

Turbine Generator					Field Gas Fuel			
COG01	PPMV	lb/MMCF[2]	lb/MMBtu[3]	MW	Lb/hr	lb/day	lb/yr	tpy
NOx	5		0.006	46	1.692	40.606	14821.132	7.411
VOC		2.1	0.0021	16	0.592	14.212	5187.396	2.594
CO	400	82	0.082	28	23.123	554.946	202555.465	101.278
SOx	98			64	4.660	111.849	40824.830	20.412
PM10		6.6	0.0066		1.861	44.666	16303.245	8.152
PM2.5		6.6	0.0066		1.861	44.666	16303.245	8.152
H2S	2			34	0.051	1.213	442.616	0.221

[1]Per Client

[2]AP-42 Tables 3.1-1 & 3.1-2a

[3]SJVAPCD Rule 4703 for NOx and CO

Drilling Mud Sump

0.0021	tons/well-day	Mike Kelly Spreadsheet DRL_Emissions.xlsx received Feb 15, 2015
23	days	10,000 foot well
16	MW VOC	Per Mike Kelly
34	MW H2S	
100	PPMV H2S	Per Client

	lb/hr	lb/day	lb/yr	tpy
VOC	0.01	0.26	96.60	0.05
H2S	2.34E-06	5.62E-05	2.05E-02	1.03E-05

Boiler

10	MMBtu/hr
1000	scf/MMBtu
100	ppmv H2S[1]
0.98	H2S Destruction Efficiency
0.01	MMCF/hr
87.6	MMCF/yr

Boiler					Field Gas Fuel			
BLR01	PPMV	lb/MMCF[2]	lb/MMBtu[3]	MW	Lb/hr	lb/day	lb/yr	tpy
NOx	9		0.011	46	0.110	2.640	963.600	0.482
VOC		5.5	0.0055	16	0.055	1.320	481.800	0.241
CO		84	0.084	28	0.840	20.160	7358.400	3.679
SOx	98			64	0.165	3.966	1447.766	0.724
PM10		7.6	0.0076		0.076	1.824	665.760	0.333
PM2.5		7.6	0.0076		0.076	1.824	665.760	0.333
H2S	2			34	0.002	0.043	15.696	0.008

[1]Per Client

[2]AP-42 Tables 1.4-1 & 1.4-2

[3]SJVAPCD Rule 4306, Table 1, Enhanced Option for NOx and CO

Thermally Enhanced Oil Recovery

0.88	lb/day
16	MW VOC
34	MW H2S
100	ppmv H2S in VOC

	lb/hr	lb/day	lb/yr	tpy
VOC	0.04	0.88	321.20	0.16
H2S	7.79E-06	1.87E-04	6.83E-02	3.41E-05

Flare

100	MMBtu/hr
1000	scf/MMBtu
100	ppmv H2S[1]
0.98	H2S Destruction Efficiency
0.1	MMCF/hr
876	MMCF/yr

Flare					Field Gas Fuel			
FLR01	PPMV	lb/MMCF[2]	lb/MMBtu[3]	MW	Lb/hr	lb/day	lb/yr	tpy
NOx	15		0.133	46	13.300	319.200	116508.000	58.254
VOC		5.5	0.0027	16	0.270	6.480	2365.200	1.183
CO		68	0.068	28	6.800	163.200	59568.000	29.784
SOx	98			64	1.653	39.665	14477.660	7.239
PM10		7.6	0.0076		0.760	18.240	6657.600	3.329
PM2.5		7.6	0.0076		0.760	18.240	6657.600	3.329
H2S	2			34	0.018	0.430	156.964	0.078

[1]Per Client

[2]AP-42 Tables 13.5-1

[3]SJVAPCD Rule 4311 for NOx and VOC

Oilfield Equipment Light Crude Oil Fugitives

Name	Oilfield Equipment Light Crude Oil Fugitives				
Applicability	Use this spreadsheet for VOC fugitive emission from Oilfield Equipment using Light				
Author or updater	Matthew Cegielski		*Last Update*	June 18, 2013	
Facility:	KERN EIR				
ID#:	Piping Components				
Project #:	21815				

Inputs	lb /hr	lb /yr	**Formula**
VOC Rate	1.25E-02	109.5	Emissions are calculated by the multiplication of each VOC Rate and Emission Factor. Hydrogen Sulfide emissions are variable, depending on source and control measures and should be provided by the project engineer

Substances	CAS#	Emission Factor lbs/ lb VOC	LB/HR	LB/YR
"1,2,4 Trimethylbenzene"	**95636**	9.90E-05	1.24E-06	1.08E-02
Benzene	**71432**	2.95E-03	3.69E-05	3.23E-01
Cyclohexane	**110827**	1.44E-04	1.80E-06	1.58E-02
Ethylbenzene	**100414**	9.39E-04	1.17E-05	1.03E-01
n-Hexane	**110543**	2.17E-02	2.72E-04	2.38E+00
Toluene	**108883**	3.31E-03	4.13E-05	3.62E-01
Xylenes	**1330207**	1.74E-03	2.18E-05	1.91E-01
Hydrogen sulfide	**7783064**	100 ppmv	2.66E-06	2.33E-02

References:

Investigator: Albert C. Censullo, Ph.D. California Polytechnic State University, San Luis Obispo. 1991. A832-059.

Pollutants required for toxic reporting: HAPS w/o Risk Factor or Non - HAPs   Current as of update date

Name — Oilfield Natural Gas-Fired + Waste Gas Flare

Applicability	Use this spreadsheet for Natural Gas/Waste Gas-Fired Flares at an Oilfield or Refinery		
Author or updater	Matthew Cegielski	*Last Update*	June 18, 2013
Facility:	Kern EIR		
ID#:	10 MMBtu/hr Flare		
Project #:			

Inputs	MMscf/hr	MMscf/yr
Flare Rate	1.00E-02	87.60
Specific Gravity of Gas	0.45	
Destruction Efficiency %	98.00	
Methane %	100.00	
	MMscf/hr	MMscf/yr
Flare Gas Methane Rate	0.01	87.60
	MMscf/hr	MMscf/yr
Uncombusted VOCs Rate	2.00E-04	1.75E+00

Formula

Emissions are the result of combustion plus the pass through of uncombusted VOCs. Emissions are determined by the multiplication of each corresponding process Rate and Emission Factor. Enter the Destruction efficiency as a whole number. Default is 98. Enter specific gravity of gas as a decimal. Default is 0.45 Enter the % methane as a whole number. Flare gas assumed to be 100% as a worst case if value is unknown. Waste gas characterization defaults are listed on the Reference tab and can be modified by changing the mole fraction values if so desired.

Substance	CAS#	Flare Gas Methane Combustion Emission Factor	LB/HR	LB/YR	Refinery Gas Composition Emission Factor lbs/ MMscf**	LB/HR	LB/YR	Total LB/HR	Total LB/YR
Acetaldehyde	**75070**	4.30E-02	4.30E-04	3.77E+00	0	0.00E+00	0.00E+00	4.30E-04	3.77E+00
Acrolein	**107028**	1.00E-02	1.00E-04	8.76E-01	0	0.00E+00	0.00E+00	1.00E-04	8.76E-01
Benzene	**71432**	1.59E-01	1.59E-03	1.39E+01	1.41E+02	2.81E-02	2.46E+02	2.97E-02	2.60E+02
Cyclohexane	**110827**	0.00E+00	0.00E+00	0.00E+00	1.22E+02	2.44E-02	2.14E+02	2.44E-02	2.14E+02
Ethylbenzene	**100414**	1.44E+00	1.44E-02	1.26E+02	2.63E+00	5.26E-04	4.61E+00	1.50E-02	1.31E+02
Formaldehyde	**50000**	1.17E+00	1.17E-02	1.02E+02	0	0.00E+00	0.00E+00	1.17E-02	1.02E+02
n-Hexane	**110543**	2.90E-02	2.90E-04	2.54E+00	1.96E+02	3.91E-02	3.43E+02	3.94E-02	3.45E+02
Hydrogen sulfide	**7783064**	100 ppmv	1.79E-03	1.57E+01	2.33E+02	4.66E-02	4.08E+02	4.83E-02	4.23E+02
Naphthalene	**91203**	1.10E-02	1.10E-04	9.64E-01	0	0.00E+00	0.00E+00	1.10E-04	9.64E-01
PAH's	**1151**	1.40E-02	1.40E-04	1.23E+00	0	0.00E+00	0.00E+00	1.40E-04	1.23E+00
Propylene	**115071**	2.44E+00	2.44E-02	2.14E+02	0	0.00E+00	0.00E+00	2.44E-02	2.14E+02
Toluene	**108883**	5.80E-02	5.80E-04	5.08E+00	1.71E+01	3.43E-03	3.00E+01	4.01E-03	3.51E+01
Xylenes	**1330207**	2.90E-02	2.90E-04	2.54E+00	3.26E+00	6.53E-04	5.72E+00	9.43E-04	8.26E+00

References:

* The emission factors were based on the May 2001 update of VCAPCD AB 2588 Combustion Emission Factors

TDA's Direct Oxidation Process for Sulfur Recovery Specific gravity of the gas analyzed was 0.45

Pollutants required for toxic reporting: HAPS w/o Risk Factor or Non - HAPs Current as of update date

Name	Oilfield Equipment Light Crude Oil Fugitives			
Applicability	Use this spreadsheet for VOC fugitive emission from Oilfield Equipment using Light			
Author or updater	Matthew Cegielski	*Last Update*	June 18, 2013	
Facility:	KERN EIR			
ID#:	Sump			
Project #:	21815			

Inputs	lb /hr	lb /yr	**Formula**
VOC Rate	2.63E-01	2,299.5	Emissions are calculated by the multiplication of each VOC Rate and Emission Factor. Hydrogen Sulfide emissions are variable, depending on source and control measures and should be provided by the project engineer

Substances	CAS#	Emission Factor lbs/ lb VOC	LB/HR	LB/YR
"1,2,4 Trimethylbenzene"	**95636**	9.90E-05	2.60E-05	2.28E-01
Benzene	**71432**	2.95E-03	7.74E-04	6.78E+00
Cyclohexane	**110827**	1.44E-04	3.78E-05	3.31E-01
Ethylbenzene	**100414**	9.39E-04	2.46E-04	2.16E+00
n-Hexane	**110543**	2.17E-02	5.71E-03	5.00E+01
Toluene	**108883**	3.31E-03	8.68E-04	7.60E+00
Xylenes	**1330207**	1.74E-03	4.58E-04	4.01E+00
Hydrogen sulfide	**7783064**	100 ppmv	5.58E-05	4.89E-01

References:

Investigator: Albert C. Censullo, Ph.D. California Polytechnic State University, San Luis Obispo. 1991. A832-059.

Pollutants required for toxic reporting: HAPS w/o Risk Factor or Non - HAPs Current as of update date

Name	Oilfield Equipment Light Crude Oil Fugitives			
Applicability	Use this spreadsheet for VOC fugitive emission from Oilfield Equipment using Light			
Author or updater	Matthew Cegielski	*Last Update*	June 18, 2013	
Facility:	KERN EIR			
ID#:	Vacuum Truck			
Project #:	21815			

Inputs	lb /hr	lb /yr	**Formula**
VOC Rate	7.32E-01	6,413.6	Emissions are calculated by the multiplication of each VOC Rate and Emission Factor. Hydrogen Sulfide emissions are variable, depending on source and control measures and should be provided by the project engineer

Substances	CAS#	Emission Factor lbs/ lb VOC	LB/HR	LB/YR
"1,2,4 Trimethylbenzene"	**95636**	9.90E-05	7.25E-05	6.35E-01
Benzene	**71432**	2.95E-03	2.16E-03	1.89E+01
Cyclohexane	**110827**	1.44E-04	1.05E-04	9.24E-01
Ethylbenzene	**100414**	9.39E-04	6.87E-04	6.02E+00
n-Hexane	**110543**	2.17E-02	1.59E-02	1.39E+02
Toluene	**108883**	3.31E-03	2.42E-03	2.12E+01
Xylenes	**1330207**	1.74E-03	1.28E-03	1.12E+01
Hydrogen sulfide	**7783064**	100 ppmv	1.56E-04	1.36E+00

References:
Investigator: Albert C. Censullo, Ph.D. California Polytechnic State University, San Luis Obispo. 1991. A832-059.
Pollutants required for toxic reporting: HAPS w/o Risk Factor or Non - HAPs   Current as of update date

Name	Oilfield Equipment Light Crude Oil Fugitives			
Applicability	Use this spreadsheet for VOC fugitive emission from Oilfield Equipment using Light			
Author or updater	Matthew Cegielski	*Last Update*	June 18, 2013	
Facility:	KERN EIR			
ID#:	Tank 3 - 1000 Bbl			
Project #:	21815			

Inputs	lb /hr	lb /yr
VOC Rate	8.69E-01	7,610.3

Formula

Emissions are calculated by the multiplication of each VOC Rate and Emission Factor. Hydrogen Sulfide emissions are variable, depending on source and control measures and should be provided by the project engineer

Substances	CAS#	Emission Factor lbs/ lb VOC	LB/HR	LB/YR
"1,2,4 Trimethylbenzene"	**95636**	9.90E-05	8.60E-05	7.53E-01
Benzene	**71432**	2.95E-03	2.56E-03	2.25E+01
Cyclohexane	**110827**	1.44E-04	1.25E-04	1.10E+00
Ethylbenzene	**100414**	9.39E-04	8.16E-04	7.15E+00
n-Hexane	**110543**	2.17E-02	1.89E-02	1.65E+02
Toluene	**108883**	3.31E-03	2.87E-03	2.52E+01
Xylenes	**1330207**	1.74E-03	1.51E-03	1.33E+01
Hydrogen sulfide	**7783064**	100 ppmv	1.85E-04	1.62E+00

References:
Investigator: Albert C. Censullo, Ph.D. California Polytechnic State University, San Luis Obispo. 1991. A832-059.
Pollutants required for toxic reporting: HAPS w/o Risk Factor or Non - HAPs   Current as of update date

Name	Oilfield Equipment Light Crude Oil Fugitives			
Applicability	Use this spreadsheet for VOC fugitive emission from Oilfield Equipment using Light			
Author or updater	Matthew Cegielski	*Last Update*	June 18, 2013	
Facility:	KERN EIR			
ID#:	Tank 2 - 1000 Bbl			
Project #:	21815			

Inputs	lb /hr	lb /yr	**Formula**
VOC Rate	8.69E-01	7,610.3	Emissions are calculated by the multiplication of each VOC Rate and Emission Factor. Hydrogen Sulfide emissions are variable, depending on source and control measures and should be provided by the project engineer

Substances	**CAS#**	**Emission Factor lbs/ lb VOC**	**LB/HR**	**LB/YR**
"1,2,4 Trimethylbenzene"	**95636**	9.90E-05	8.60E-05	7.53E-01
Benzene	**71432**	2.95E-03	2.56E-03	2.25E+01
Cyclohexane	**110827**	1.44E-04	1.25E-04	1.10E+00
Ethylbenzene	**100414**	9.39E-04	8.16E-04	7.15E+00
n-Hexane	**110543**	2.17E-02	1.89E-02	1.65E+02
Toluene	**108883**	3.31E-03	2.87E-03	2.52E+01
Xylenes	**1330207**	1.74E-03	1.51E-03	1.33E+01
Hydrogen sulfide	**7783064**	100 ppmv	1.85E-04	1.62E+00

References:
Investigator: Albert C. Censullo, Ph.D. California Polytechnic State University, San Luis Obispo. 1991. A832-059.
Pollutants required for toxic reporting: HAPS w/o Risk Factor or Non - HAPs Current as of update date

Name	Oilfield Equipment Light Crude Oil Fugitives			
Applicability	Use this spreadsheet for VOC fugitive emission from Oilfield Equipment using Light			
Author or updater	Matthew Cegielski	*Last Update*	June 18, 2013	
Facility:	KERN EIR			
ID#:	Tank 1 - 3000 Bbl			
Project #:	21815			

Inputs	lb /hr	lb /yr	**Formula**
VOC Rate	6.86E-01	6,011.6	Emissions are calculated by the multiplication of each VOC Rate and Emission Factor. Hydrogen Sulfide emissions are variable, depending on source and control measures and should be provided by the project engineer

Substances	CAS#	Emission Factor lbs/ lb VOC	LB/HR	LB/YR
"1,2,4 Trimethylbenzene"	95636	9.90E-05	6.79E-05	5.95E-01
Benzene	71432	2.95E-03	2.02E-03	1.77E+01
Cyclohexane	110827	1.44E-04	9.88E-05	8.66E-01
Ethylbenzene	100414	9.39E-04	6.44E-04	5.64E+00
n-Hexane	110543	2.17E-02	1.49E-02	1.31E+02
Toluene	108883	3.31E-03	2.27E-03	1.99E+01
Xylenes	1330207	1.74E-03	1.20E-03	1.05E+01
Hydrogen sulfide	7783064	100 ppmv	1.46E-04	1.28E+00

References:

Investigator: Albert C. Censullo, Ph.D. California Polytechnic State University, San Luis Obispo. 1991. A832-059.

Pollutants required for toxic reporting: HAPS w/o Risk Factor or Non - HAPs   Current as of update date

Name

Petroleum Process Heaters-Natural Gas and Refinery Gas

Applicability	Use this spreadsheet for Petroleum Process Heaters fueled by Natural Gas and Refinery Gas. Entries required in yellow areas, output in grey areas.				
Author or updater	Matthew Cegielski		*Last Update*	December 9, 2013	
Facility:	Kern EIR				
ID#:	8MMBtu/hr Process Heater				
Project #:					

Inputs	MMscf/hr	MMscf /yr	**Formula**
Usage Rate	8.00E-03	70.1	Emissions are calculated by the multiplication of the Usage Rate and Emission Factors.

Substances	CAS#	Natural Gas and Refinery Gas Emission Factor lbs/MMscf*	LB/HR	LB/YR
Acenaphthene	**83329**	1.81E-05	1.45E-07	1.27E-03
Acenaphthylene	**208968**	1.72E-04	1.38E-06	1.21E-02
Acetaldehyde	**75070**	1.67E-02	1.34E-04	1.17E+00
Acrolein	**107028**	2.84E-03	2.27E-05	1.99E-01
Anthracene	**120127**	1.43E-05	1.14E-07	1.00E-03
Benz(a)anthracene	**56553**	1.67E-05	1.34E-07	1.17E-03
Benzene	**71432**	2.44E-02	1.95E-04	1.71E+00
Benzo(a)pyrene	**50328**	1.10E-05	8.80E-08	7.71E-04
Benzo(b)fluoranthene	**205992**	4.19E-06	3.35E-08	2.94E-04
"Benzo(g,h,i)perylene"	**191242**	9.55E-07	7.64E-09	6.69E-05
Benzo(k)fluoranthene	**207089**	3.18E-06	2.54E-08	2.23E-04
Chrysene	**218019**	1.24E-06	9.92E-09	8.69E-05
"Dibenz(a,h)anthracene"	**53703**	2.08E-07	1.66E-09	1.46E-05
Fluoranthene	**206440**	3.82E-05	3.06E-07	2.68E-03
Fluorene	**86737**	1.69E-03	1.35E-05	1.18E-01

Formaldehyde	**50000**	8.89E-02	7.11E-04	6.23E+00
Hydrogen sulfide	**7783064**	100 ppmv	1.43E-03	1.26E+01
"Indeno(1,2,3-cd)pyrene"	**193395**	6.67E-07	5.34E-09	4.67E-05
Naphthalene	**91203**	6.18E-03	4.94E-05	4.33E-01
Phenanthrene	**85018**	4.30E-04	3.44E-06	3.01E-02
Phenol	**108952**	2.08E-03	1.66E-05	1.46E-01
Propylene	**115071**	1.38E-02	1.10E-04	9.67E-01
Pyrene	**129000**	2.62E-05	2.10E-07	1.84E-03
Toluene	**108883**	3.03E-02	2.42E-04	2.12E+00
Xylenes	**1330207**	3.49E-02	2.79E-04	2.45E+00

References:

* The emission factors were taken from the API and WSPA emission source tests (Hansell and England, 1998) see Table D-8a pg. D-22 in (Review Draft) December 2009 Emission Estimation Protocol for Petroleum Refineries

Pollutants required for toxic reporting: HAPS w/o Risk Factor or Non - HAPs   Current as of update date

Name	Petroleum Steam Generators-Natural Gas and Casing Vapor Recovery Gas			
Applicability	Use this spreadsheet for Petroleum Steam Generators fueled by Natural Gas and Casing Vapor Recovery Gas. Entries required in yellow areas, output in grey areas.			
Author or updater	Matthew Cegielski	*Last Update*	December 4, 2013	
Facility:	Kern EIR			
ID#:	85 MMBtu/hr Steam Generator			
Project #:				

Inputs	MMscf /hr	MMscf /yr	**Formula**
Usage Rate	8.50E-02	744.6	Emissions are calculated by the multiplication of the Usage Rate and Emission Factors.

Substance	CAS#	Natural Gas and Casing Vapor Recovery Gas Emission Factor lbs/MMscf*	LB/HR	LB/YR
Acenaphthene	**83329**	2.38E-06	2.02E-07	1.77E-03
Acenaphthylene	**208968**	1.03E-05	8.76E-07	7.67E-03
Acetaldehyde	**75070**	2.67E-02	2.27E-03	1.99E+01
Acrolein	**107028**	1.82E-02	1.55E-03	1.36E+01
Anthracene	**120127**	3.82E-06	3.25E-07	2.84E-03
Benz(a)anthracene	**56553**	2.16E-06	1.84E-07	1.61E-03
Benzene	**71432**	6.21E-03	5.28E-04	4.62E+00
Benzo(a)pyrene	**50328**	1.33E-06	1.13E-07	9.90E-04
Benzo(b)fluoranthene	**205992**	4.78E-06	4.06E-07	3.56E-03
"Benzo(g,h,i)perylene"	**191242**	1.75E-06	1.49E-07	1.30E-03
Benzo(k)fluoranthene	**207089**	1.39E-06	1.18E-07	1.03E-03
Chrysene	**218019**	2.16E-06	1.84E-07	1.61E-03
"Dibenz(a,h)anthracene"	**53703**	6.82E-07	5.80E-08	5.08E-04

Ethylbenzene	**100414**	1.86E-02	1.58E-03	1.38E+01
Fluoranthene	**206440**	9.03E-06	7.68E-07	6.72E-03
Fluorene	**86737**	1.30E-05	1.11E-06	9.68E-03
Formaldehyde	**50000**	7.01E-02	5.96E-03	5.22E+01
Hydrogen sulfide	**7783064**	100 ppm	1.52E-02	1.33E+02
"Indeno(1,2,3-cd)pyrene"	**193395**	2.38E-06	2.02E-07	1.77E-03
Naphthalene	**91203**	5.54E-04	4.71E-05	4.13E-01
Phenanthrene	**85018**	3.17E-05	2.69E-06	2.36E-02
Propylene	**115071**	6.30E-01	5.36E-02	4.69E+02
Pyrene	**129000**	1.74E-05	1.48E-06	1.30E-02
Toluene	**108883**	3.08E-02	2.62E-03	2.29E+01
Xylenes	**1330207**	4.03E-02	3.43E-03	3.00E+01

References:
* The emission factors were taken from the API and WSPA emission source tests (Hansell and England, 1998) see page 4-18 Table 4-4 in (Review Draft) December 2009 Emission Estimation Protocol for Petroleum Refineries (note reference c, emission factors specifically for steam generators, even though table states boilers,max value taken from appendix table D-21A)
Non - HAPs, Toxics current as of update date

Name	Field Gas-Fired Four Stroke Lean Burn (4SLB) Internal Combustion Engine			
Applicability	Use this spreadsheet for Field Gas-Fired Internal Combustion 4 Stroke Lean Burn (4SLB) Engine. Entries			
Author or updater	Matthew Cegielski	*Last Update*	December 15, 2014	
Facility:	Kern EIR			
ID#:	1000 bhp ICE			
Project #:				

Inputs	MMscf /hr	MMscf /yr	**Formula**
Field Gas usage rate	8.48E-03	74.241	Supply the necessary rate in MMscf. Emissions are calculated by the multiplication of Fuel Rates and Emission Factors.

Substances	**CAS#**	**Emission Factor lbs/ MMscf**	**LB/HR**	**LB/YR**
Benzene	**71432**	1.70E+00	1.44E-02	1.26E+02
Formaldehyde	**50000**	4.20E+01	3.56E-01	3.12E+03
Propylene	**115071**	1.60E+01	1.36E-01	1.19E+03
Toluene	**108883**	7.70E-01	6.53E-03	5.72E+01
Xylenes	**1330207**	3.90E-01	3.31E-03	2.90E+01
Hydrogen sulfide	**7783064**	100 ppmv	1.52E-03	1.33E+01

References:

Petroleum Refineries . Source data is from API and WSPA emission source tests (Hansell and England, 1998)

Pollutants required for toxic reporting: HAPS w/o Risk Factor or Non - HAPs   Current as of update date

Diesel Emissions
Well Construction

Diesel Particulate Matter	9901	2.03	18.70

Name	Oilfield Field Gas Turbine - CATEF				
Applicability	Use this spreadsheet for Natural Gas/Waste Gas-Fired Flares at an Oilfield or Refinery				
Author or updater	Matthew Cegielski	*Last Update*	June 18, 2013		
Facility:	Kern EIR				
ID#:	33 MW Field Gas Cogeneration Turbine				
Project #:					

Inputs	MMscf/hr	MMscf/yr	Formula
Fuel Rate	2.82E-01	2,470.32	Emissions are the result of combustion plus the pass through of uncombusted VOCs. Emissions are determined by the multiplication of each corresponding process Rate and Emission Factor. 98% Destruction efficiency is assumed. Enter specific gravity of gas as a decimal. Default is 0.45 Enter the % methane as a whole number. Waste gas characterization defaults are listed on the Reference tab and can be modified by changing the mole fraction values if so desired.
Specific Gravity of Gas	0.45		
Destruction Efficiency %	98.00		
Methane %	100.00		
	MMscf/hr	MMscf/yr	
Flare Gas Methane Rate	0.282	2,470.32	
	MMscf/hr	MMscf/yr	
Uncombusted VOCs Rate	5.64E-03	4.94E+01	

Substance	CAS#	CATEF lbs/ MMscf*	LB/HR	LB/YR
Benzene	71432	1.46E-02	4.12E-03	3.61E+01
Hydrogen sulfide	7783064	1.79E-01	5.05E-02	4.43E+02
Naphthalene	91203	5.79E-03	1.63E-03	1.43E+01
PAH's	1151	2.55E-04	7.20E-05	6.30E-01
Formaldehyde	50000	1.84E-01	5.19E-02	4.55E+02

PAH	CAS
1.26E-05	206440
8.53E-08	91587
8.10E-05	91576
1.62E-05	83329
1.10E-06	208968
2.48E-07	120127
3.30E-07	56556
7.99E-07	50328
1.44E-06	205992
2.24E-06	192972
5.31E-06	191242
2.45E-07	207089
1.78E-05	218019
6.91E-06	53703
3.24E-05	86737
3.92E-06	193395
9.50E-07	198550
6.19E-05	85018
9.67E-06	129000
2.55E-04	**TOTAL**

H2S
34 MW
379.5 Ft3/lb-mol
100 ppmv
0.98
0.179183

References:
* The emission factors were based on the May 2001 update of VCAPCD AB 2588 Combustion Emission Factors
TDA's Direct Oxidation Process for Sulfur Recovery Specific gravity of the gas analyzed was 0.45
Pollutants required for toxic reporting: HAPS w/o Risk Factor or Non - HAPs Current as of update date

Name	Oilfield Equipment Light Crude Oil Fugitives				
Applicability	Use this spreadsheet for VOC fugitive emission from Oilfield Equipment using Light				
Author or updater	Matthew Cegielski		*Last Update*	June 18, 2013	
Facility:	KERN EIR				
ID#:	Sump				
Project #:	21815				

Inputs	lb /hr	lb /yr	**Formula**
VOC Rate	1.10E-02	96.6	Emissions are calculated by the multiplication of each VOC Rate and Emission Factor. Hydrogen Sulfide emissions are variable, depending on source and control measures and should be provided by the project engineer

Substances	CAS#	Emission Factor lbs/ lb VOC	LB/HR	LB/YR
"1,2,4 Trimethylbenzene"	95636	9.90E-05	1.09E-06	9.56E-03
Benzene	71432	2.95E-03	3.25E-05	2.85E-01
Cyclohexane	110827	1.44E-04	1.59E-06	1.39E-02
Ethylbenzene	100414	9.39E-04	1.04E-05	9.07E-02
n-Hexane	110543	2.17E-02	2.40E-04	2.10E+00
Toluene	108883	3.31E-03	3.65E-05	3.19E-01
Xylenes	1330207	1.74E-03	1.92E-05	1.68E-01
Hydrogen sulfide	7783064	100 ppmv	2.34E-06	2.05E-02

References:

Investigator: Albert C. Censullo, Ph.D. California Polytechnic State University, San Luis Obispo. 1991. A832-059.

Pollutants required for toxic reporting: HAPS w/o Risk Factor or Non - HAPs   Current as of update date

Name

Petroleum Steam Generators-Natural Gas and Casing Vapor Recovery Gas

Applicability	Use this spreadsheet for Petroleum Steam Generators fueled by Natural Gas and Casing Vapor Recovery Gas. Entries required in yellow areas, output in grey areas.				
Author or updater	Matthew Cegielski		*Last Update*	December 4, 2013	
Facility:	Kern EIR				
ID#:	10 MMBtu/hr Boiler				
Project #:					
Inputs	MMscf /hr	MMscf /yr	**Formula**		
Usage Rate	1.00E-02	87.6	Emissions are calculated by the multiplication of the Usage Rate and Emission Factors.		

Substance	CAS#	Natural Gas and Casing Vapor Recovery Gas Emission Factor lbs/MMscf*	LB/HR	LB/YR
Acenaphthene	**83329**	2.38E-06	2.38E-08	2.08E-04
Acenaphthylene	**208968**	1.03E-05	1.03E-07	9.02E-04
Acetaldehyde	**75070**	2.67E-02	2.67E-04	2.34E+00
Acrolein	**107028**	1.82E-02	1.82E-04	1.59E+00
Anthracene	**120127**	3.82E-06	3.82E-08	3.35E-04
Benz(a)anthracene	**56553**	2.16E-06	2.16E-08	1.89E-04
Benzene	**71432**	6.21E-03	6.21E-05	5.44E-01
Benzo(a)pyrene	**50328**	1.33E-06	1.33E-08	1.17E-04
Benzo(b)fluoranthene	**205992**	4.78E-06	4.78E-08	4.19E-04
"Benzo(g,h,i)perylene"	**191242**	1.75E-06	1.75E-08	1.53E-04
Benzo(k)fluoranthene	**207089**	1.39E-06	1.39E-08	1.22E-04
Chrysene	**218019**	2.16E-06	2.16E-08	1.89E-04
"Dibenz(a,h)anthracene"	**53703**	6.82E-07	6.82E-09	5.97E-05

Ethylbenzene	**100414**	1.86E-02	1.86E-04	1.63E+00
Fluoranthene	**206440**	9.03E-06	9.03E-08	7.91E-04
Fluorene	**86737**	1.30E-05	1.30E-07	1.14E-03
Formaldehyde	**50000**	7.01E-02	7.01E-04	6.14E+00
Hydrogen sulfide	**7783064**	100 ppmv	1.79E-03	1.57E+01
"Indeno(1,2,3-cd)pyrene"	**193395**	2.38E-06	2.38E-08	2.08E-04
Naphthalene	**91203**	5.54E-04	5.54E-06	4.85E-02
Phenanthrene	**85018**	3.17E-05	3.17E-07	2.78E-03
Propylene	**115071**	6.30E-01	6.30E-03	5.52E+01
Pyrene	**129000**	1.74E-05	1.74E-07	1.52E-03
Toluene	**108883**	3.08E-02	3.08E-04	2.70E+00
Xylenes	**1330207**	4.03E-02	4.03E-04	3.53E+00

References:
* The emission factors were taken from the API and WSPA emission source tests (Hansell and England, 1998) see page 4-18 Table 4-4 in (Review Draft) December 2009 Emission Estimation Protocol for Petroleum Refineries (note reference c, emission factors specifically for steam generators, even though table states boilers,max value taken from appendix table D-21A)
Non - HAPs, Toxics current as of update date

Name	**Oilfield Equipment Light Crude Oil Fugitives**			
Applicability	Use this spreadsheet for VOC fugitive emission from Oilfield Equipment using Light			
Author or updater	Matthew Cegielski	*Last Update*	June 18, 2013	
Facility:	KERN EIR			
ID#:	TEOR			
Project #:	21815			

Inputs	lb /hr	lb /yr	**Formula**
VOC Rate	3.67E-02	321.2	Emissions are calculated by the multiplication of each VOC Rate and Emission Factor. Hydrogen Sulfide emissions are variable, depending on source and control measures and should be provided by the project engineer

Substances	CAS#	Emission Factor lbs/ lb VOC	LB/HR	LB/YR
"1,2,4 Trimethylbenzene"	**95636**	9.90E-05	3.63E-06	3.18E-02
Benzene	**71432**	2.95E-03	1.08E-04	9.48E-01
Cyclohexane	**110827**	1.44E-04	5.28E-06	4.63E-02
Ethylbenzene	**100414**	9.39E-04	3.44E-05	3.02E-01
n-Hexane	**110543**	2.17E-02	7.97E-04	6.98E+00
Toluene	**108883**	3.31E-03	1.21E-04	1.06E+00
Xylenes	**1330207**	1.74E-03	6.39E-05	5.60E-01
Hydrogen sulfide	**7783064**	100 ppmv	7.79E-06	6.83E-02

References:

Investigator: Albert C. Censullo, Ph.D. California Polytechnic State University, San Luis Obispo. 1991. A832-059.

Pollutants required for toxic reporting: HAPS w/o Risk Factor or Non - HAPs   Current as of update date

Name — Oilfield Natural Gas-Fired + Waste Gas Flare

Applicability	Use this spreadsheet for Natural Gas/Waste Gas-Fired Flares at an Oilfield or Refinery			
Author or updater	Matthew Cegielski	*Last Update*	June 18, 2013	
Facility:	Kern EIR			
ID#:	100 MMBtu/hr Flare			
Project #:				

Inputs	MMscf/hr	MMscf/yr
Flare Rate	1.00E-01	876.00
Specific Gravity of Gas	0.45	
Destruction Efficiency %	98.00	
Methane %	100.00	
	MMscf/hr	MMscf/yr
Flare Gas Methane Rate	0.1	876.00
	MMscf/hr	MMscf/yr
Uncombusted VOCs Rate	2.00E-03	1.75E+01

Formula

Emissions are the result of combustion plus the pass through of uncombusted VOCs. Emissions are determined by the multiplication of each corresponding process Rate and Emission Factor. Enter the Destruction efficiency as a whole number. Default is 98. Enter specific gravity of gas as a decimal. Default is 0.45 Enter the % methane as a whole number. Flare gas assumed to be 100% as a worst case if value is unknown. Waste gas characterization defaults are listed on the Reference tab and can be modified by changing the mole fraction values if so desired.

Substance	CAS#	Flare Gas Methane Combustion Emission Factor	LB/HR	LB/YR	Refinery Gas Composition Emission Factor lbs/ MMscf**	LB/HR	LB/YR	Total LB/HR	Total LB/YR
Acetaldehyde	**75070**	4.30E-02	4.30E-03	3.77E+01	0	0.00E+00	0.00E+00	4.30E-03	3.77E+01
Acrolein	**107028**	1.00E-02	1.00E-03	8.76E+00	0	0.00E+00	0.00E+00	1.00E-03	8.76E+00
Benzene	**71432**	1.59E-01	1.59E-02	1.39E+02	1.41E+02	2.81E-01	2.46E+03	2.97E-01	2.60E+03
Cyclohexane	**110827**	0.00E+00	0.00E+00	0.00E+00	1.22E+02	2.44E-01	2.14E+03	2.44E-01	2.14E+03
Ethylbenzene	**100414**	1.44E+00	1.44E-01	1.26E+03	2.63E+00	5.26E-03	4.61E+01	1.50E-01	1.31E+03
Formaldehyde	**50000**	1.17E+00	1.17E-01	1.02E+03	0	0.00E+00	0.00E+00	1.17E-01	1.02E+03
n-Hexane	**110543**	2.90E-02	2.90E-03	2.54E+01	1.96E+02	3.91E-01	3.43E+03	3.94E-01	3.45E+03
Hydrogen sulfide	**7783064**	100 ppmv	1.79E-03	1.57E+01	2.33E+02	4.66E-01	4.08E+03	4.67E-01	4.09E+03
Naphthalene	**91203**	1.10E-02	1.10E-03	9.64E+00	0	0.00E+00	0.00E+00	1.10E-03	9.64E+00
PAH's	**1151**	1.40E-02	1.40E-03	1.23E+01	0	0.00E+00	0.00E+00	1.40E-03	1.23E+01
Propylene	**115071**	2.44E+00	2.44E-01	2.14E+03	0	0.00E+00	0.00E+00	2.44E-01	2.14E+03
Toluene	**108883**	5.80E-02	5.80E-03	5.08E+01	1.71E+01	3.43E-02	3.00E+02	4.01E-02	3.51E+02
Xylenes	**1330207**	2.90E-02	2.90E-03	2.54E+01	3.26E+00	6.53E-03	5.72E+01	9.43E-03	8.26E+01

References:

* The emission factors were based on the May 2001 update of VCAPCD AB 2588 Combustion Emission Factors

TDA's Direct Oxidation Process for Sulfur Recovery Specific gravity of the gas analyzed was 0.45

Pollutants required for toxic reporting: HAPS w/o Risk Factor or Non - HAPs Current as of update date

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Appendix D –
AERMOD

(Files on CD at County office)

Appendix E –
HARP2

(Files on CD at County office)

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Health Risk Assessment Report (July 2015)

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Health Risk Assessment
Kern County DEIR –
Proposed Drilling and Oil and Gas Operations

<u>Prepared by:</u>

Environmental Compliance Solutions, Inc.

171 Pier Avenue #337
Santa Monica, CA 90405

June 5, 2015

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1.0 - PROJECT OVERVIEW

This Health Risk Assessment (HRA) was prepared to support the Draft Environmental Impact Report (DEIR) currently being prepared for the proposed Amendment to Title 19 – Kern County Zoning Ordinance – Chapter 19.98 for Oil and Gas Local Permitting.

This HRA evaluates potential calculated cancer risk and acute and chronic health risk from toxic emissions associated with well construction, drilling, and completion as well as oil and gas processing equipment.

Typical well construction phasing and equipment lists were provided as part of our scope of work; along with emission calculations from all well drilling equipment. All well construction emissions were assumed to occur simultaneously for worst case, conservative assumptions.

In March 2015, the state of California released a new HRA guidance document and software. This new program was used to complete this analysis. Use of the new methodology results in calculated risk three to six times higher (300% - 600%) than results for the same emissions profiles using the model previously required for use from 1990 – February 2015.

2.0 - HEALTH RISK ASSESSMENT OVERVIEW

This HRA was performed following the Office of Environmental Health Hazard Assessment (OEHHA), Air Toxics Hot Spots Program Risk Assessment Guidelines (OEHHA, March 2015).

As recommended by the guidelines, the California Air Resources Board (CARB) Hotspots Analysis and Reporting Program, Version 2 (HARP2) (CARB, 2015) was used to perform a refined health risk assessment for potential future drilling and operational emissions. HARP2 includes three modules: a dispersion model, an exposure/dose module and a risk module. The dispersion model incorporates the United States Environmental Protection Agency (USEPA'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:

1) Emissions Estimations of Hazardous Air Pollutants;
2) Exposure Assessments;
3) Dose-response Assessments; and
4) Potential Health Risk Quantification.

Emissions Estimations of Hazardous Air Pollutants

Emission estimates involve identifying and quantifying emissions of potential regulated toxic substances from each source. OEHHA determines the relative toxicity of chemicals regulated by the State of California and determines whether or not they are carcinogenic or possibly associated with short-term or long-term non-cancer health impacts. Toxic emissions from each source were quantified.

"Hazardous air pollutants" is a term used by the federal Clean Air Act (CAA) that includes a variety of pollutants generated or emitted by industrial production activities. HAPs are also referred to as Toxic Air Contaminants (TACs) under California law (pursuant to the Tanner Act of 1983, codified at Health and Safety Code Section 39650 et. seq.).

California listed diesel exhaust or diesel particulate matter (DPM) as a toxic air contaminant in 1998. 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 mode.

The diesel particulate matter (DPM) toxicity number incorporates the cumulative health effects of all of the constituents of diesel exhaust into one risk number. Therefore, the only TAC associated with diesel equipment from well construction and completion is DPM. The primary TACs of concern for this project are diesel exhaust associated with construction equipment and drill rigs and benzene (associated with oil processing equipment).

DPM was the only set of toxic emissions analyzed from drilling operations as it accounts for 100 percent of the risk from drilling operations. Benzene accounts for approximately 94 percent of the risk from the oil processing equipment. Although the oil processing equipment scenarios did not result in off-site risk greater than 10 in one million, the risk is attributable to benzene, formaldehyde and polycyclic aromatic hydrocarbons (PAHs). All three are byproducts of natural gas combustion. Potential health effects from these compounds are summarized here.

Diesel Particulate Matter (DPM)

Respirable particles (particulate matter less than about 10 micrometers in diameter [PM_{10}]) can accumulate in the respiratory system and aggravate health problems such as asthma, bronchitis, and other lung diseases. Children, the elderly, exercising adults, and those suffering from asthma are especially vulnerable to adverse health effects of PM_{10} and $PM_{2.5}$. For purposes of this study, all PM2.5 from diesel equipment associated with well drilling (including potential dust and mobile equipment) is conservatively assumed to be toxic diesel particulate matter. DPM represents 100% of the risk associated with well drilling as it is the only TAC expected emitted during construction.

Benzene

The primary risk driver from oil processing equipment is benzene. Benzene is naturally occurring in oil and gas. Approximately 84 percent of the benzene emitted in California comes from motor vehicles, including evaporative leakage and unburned fuel exhaust. Currently, the benzene content of gasoline is less than 1 percent.

Benzene is potentially carcinogenic and naturally occurs throughout California. Benzene also has noncancer health effects. 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 liquid and vapor may irritate the skin, eyes, and upper respiratory tract in humans. Redness and blisters may result from dermal exposure to benzene.

Formaldehyde

Formaldehyde is a colorless, flammable, chemical typically used in building materials and many household products such as pressed-wood, particle board, plywood; glues and adhesives. Formaldehyde is also naturally occurring in the environment. It is a by-product of natural gas combustion.

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 by-products of natural gas combustion.

Well Drilling Emissions

Seven phases of drilling were considered as detailed below. All particulate matter of 2.5 microns (PM2.5) was considered to be toxic diesel particulate matter.

Well depths of 2,000’, 5,000’ and 10,000’ were evaluated. Using a very conservative approach, emissions from all seven phases were assumed to occur simultaneously. An initial year of 2015 was modeled and the final year of 2035 was modeled. For the 10,000’ well, 2020 was also evaluated to account for a significant decrease in diesel exhaust emissions from drill rigs and off-road diesel engines as the next CARB regulatory limits become effective. CARB’s OFFROAD emissions estimate model was used to calculate emissions from the primarily mobile and off-road diesel equipment. CARB has extensive regulations for diesel equipment with future compliance dates that will result in significant emission reductions of PM2.5 over time. CARB’s OFFROAD model can only project emissions to 2029 based on today’s available engine technologies. As a result, all emissions between 2029 – 2035 are assumed to be the same.

For this analysis, the following sources were included for evaluation:

- Well drilling (all aspects of construction, well drilling and completion) for a 2,000’, 5,000’ and 10,000’ well.

Each well evaluation consists of the following phases:

- Land Preparation;
- Drilling Survey;
- Well Drilling;
- Well Completion;
- Well Flowline;
- Pump Unit; and
- Electrical.

Numbers and types of equipment associated with each well depth are listed below. An exact equipment list for each of the seven phases and their associated emissions is included as Appendix B.

Both drilling and operational emissions are assumed to occur along a fenceline shared by an oil producer and a private resident.

Table 1 – Equipment Associated with Well Construction, Drilling and Completion*

Depth Feet	Number of Trucks	Off-Road Construction Equip.	Drill Rig HP totals	Drilling Days
10,000	9	45	3 rigs at 1,040HP each	23
5000	9	45	3 rigs at 440HP each	8
2000	9	45	3 rigs at 440HP each	4

*As previously noted, this equipment is for the combined operation of all seven phases of construction, drilling and completion.

Table 2 – Emissions Associated with Well Construction, Drilling and Completion

Depth Feet	Year[1]	Total PM2.5[2] pounds	Annual PM2.5[3] pounds	Days[4]
10,000	2015	516.89	17.23	23
10,000	2018	444.00	14.8	23
10,000	2035	151.83	5.06	23
5000	2015	171.18	5.71	8
5000	2035	35.86	1.20	8
2000	2015	97.12	3.24	4
2000	2035	20.42	0.68	4

[1]2029-2035 emissions are the same.
[2]From Vector Environmental Spreadsheet titled “DRL_EMISSIONS.xlsx”, worksheet “EMF”.

[3]Total emissions divided by 30 years per OEHHA's HARP2 exposure duration requirements.
[4]From Vector Spreadsheet titled "DRL_EMISSIONS.xlsx", worksheet "MUD".

Operational Equipment Emissions

Maximum daily and annual emissions were also quantified from an oil processing facility and a natural gas combustion facility. The equipment list and parameters was provided as part of our Scope of Work.

Oil Processing Equipment

Emissions from the following equipment were analyzed in the oil processing scenario:

- Two – 1,000 Bbl above-ground tanks;
- One – 3,000 Bbl above-ground tank;
- One 10 MMBtu/hour Flare;
- Truck loading rack;
- Fugitive emissions from valves, flanges, and one underground sump; and
- Thermally enhanced oil recovery (TEOR) equipment.

Natural Gas Combustion 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 MW Cogeneration Plant.

Potential toxic emissions from each of these sources are summarized in Appendix A.

3.0 - EXPOSURE ASSESSMENT

Exposure assessment includes air dispersion modeling, identification of emission exposure routes and estimation of exposure levels. The modeling estimates ground level concentrations based on an emission rate of one gram per second. This rate is then multiplied by the worst case potential emission rate for each substance to obtain ground level concentrations. In addition to inhalation, potential pathways of exposure to offsite receptors include dermal exposure and ingestion.

HARP2 incorporates the USEPA AERMOD (v14134) model. AERMOD predicts resulting cumulative concentrations from various emission sources. The rural setting was selected in AERMOD for this analysis. AERMOD's terrain processor, AERMAP, was used to incorporate actual terrain elevations for sources and receptors. Five years of meteorological data required for AERMOD was obtained from the San Joaquin Valley Air Pollution Control District (SJVAPCD). Bakersfield station 23155 was used for this analysis.

Three different locations within Kern County were assessed in order to capture various terrain characteristics within Kern County.

These areas were previously determined as being representative of various aspects of the county and were included as part of our Scope of Work: Western, Central and Eastern Kern County.

- Western Subarea – Midway Sunset Oilfield
- Central Subarea – No. Shafter Oilfield
- Eastern Subarea – Kern River Oilfield

Terrain in the Central Subarea is relatively flat, and modeling results would best represent dispersion characteristics with minimal terrain disturbances. More site location and terrain specific influences were observed in the Western Subarea and even more in the Eastern Subarea. Sufficient analysis of different factors that affect dispersion and other modeling inputs were covered by modeling three separate areas within Kern County. The rural setting in AERMOD was selected and the model selects the terrain variability based on real-world conditions.

Table 3 shows the UTM location of the project centers for each selected Subarea.

Table 3 - Modeled Kern County Project Locations[1]

Subarea	Easterly	Northerly
Western	255,000	3918,100
Central	293,650	3934,400
Eastern	319,800	3925,150

[1]Based on Subarea modeling locations provided by Vector dated 2/15/2015 and rounded to the nearest 164 feet. (UTM NAD83, Zone 11)

Source Modeling Parameters

Potential sources were modeled as described in the table below. Both drilling and operational emissions are assumed to occur along a fenceline shared by an oil producer and a private residence.

Table 4 - Modeling Source Characteristics and Release Parameters

Point Sources				
Source Name	Height, ft	Temp, ºF	Velocity, fps	Diameter, ft
10 MMBtu/hr Flare[1]	49.3	1831.7	65.6	1.82
100 MMBtu/hr Flare[1]	68.0	1831.7	65.6	5.76
85 MMBtu/hr Steam Generator[2]	20	200	32.0	2.5
33 MW Cogen	30	991	67.8	10.0
8 mm Btu/hour process heater[2]	15	600	29.9	1.5
1000 bhp Natural Gas Engine[2]	20	850	30	2
10 mm Btu/hour boiler[2]	20	400	23.9	1.5
Area Sources				
Source Name	Release Height, feet	X, feet	Y, feet	
Fugitive leaks	3.28	65.5	65.6	
Sump	0	30	30	
Drilling Mud Sump	0	32.8	32.8	
TEOR	0	16.5	16.5	
Circular Area Sources				
Source Name	Height, ft	Radius, ft		
1000 Bbl Tank	16.0	10.8		
1000 Bbl Tank	16.0	10.8		
3000 Bbl Tank	24.1	14.9		
Volume Sources				
Source Name	Release Height, feet	Initial Lateral Dimension, feet	Initial Vertical Dimension, feet	
Drilling	30	16.5	16.5	
Vacuum Truck Loading	13.1	1.97	3.05	

[1]Adjusted per Ohio EPA methodology.
[2]Per Scope of Work amendment 2-15-2015.
[3]Tank dimensions from tank vendor website.

4.0 - 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 a Health Risk Assessment.

Exposure Pathways

A receptor can be hypothetically exposed to a substance through several different pathways. Typically, the primary environmental exposure pathway in a health risk assessment 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 (diesel particulate matter) in the environment. For this analysis, HARP2 requires assumptions that diesel particulate matter could also be ingested via dermal (skin) absorption, soil ingestion and mother's milk ingestion. PAHs were the only pollutants analyzed for which there is a non-inhalation pathway.

Relative Toxicity

The following table represents the relative toxicity of the compounds which contributed to most of the calculated risk. For example, diesel particulate matter (DPM) (with an inhalation potency factor of 1.1) is approximately 10 times more toxic than benzene (inhalation potency factor of 0.10) and PAHs are almost four times more toxic than DPM.

Table 5 - Chemical Cancer Risk Factors[1]

Chemical	Inhalation Unit Risk[2]	Inhalation Potency Factor[2]	Non-Inhalation Oral Slope Factor
	$(\mu g/m^3)^{-1}$	$(mg/kg\text{-}d)^{-1}$	$(mg/kg\text{-}d)^{-1}$
Diesel Particulate Matter	0.0003	1.1	NA (inhalation only)
Total PAHs[3]	0.001	3.9	12.0
Formaldehyde	0.000006	0.02	NA (inhalation only)
Benzene	0.029	0.10	NA (inhalation only)

[1]May 13, 2015.
[2]Inhalation cancer potency factor: The "unit risk factor" has been replaced in the new risk assessment algorithms by a factor called the "inhalation cancer potency factor". Inhalation cancer potency factors are expressed as units of inverse dose [i.e., (mg/kg-day)-1]. They were derived from unit risk factors [units = (ug/m3)-1] by assuming that a receptor weighs 70 kilograms and breathes 20 cubic meters of air per day. The inhalation potency factor is used to calculate a potential inhalation cancer risk using the new risk assessment algorithms defined in the OEHHA, *Air Toxics Hot Spots Program; Technical Support Document for Exposure Assessment and Stochastic Analysis (August 2012)*.
[3]Polycyclic Aromatic Hydrocarbons (PAHs): (Not including naphthalene.) These substances are PAH or PAH-derivatives that have OEHHA-developed Potency Equivalency Factors (PEFs) which were approved by the Scientific Review Panel in April 1994 (see ARB document entitled *Benzo[a]pyrene as a Toxic Air Contaminant*). PAH inhalation slope factors listed here have been adjusted by the PEFs. See OEHHA's Technical Support Document: Methodologies for Derivation, Listing of Available Values, and Adjustments to Allow for Early Life Exposures (2009) for more information about the scheme. Section 8.2.3 and Appendix G of OEHHA's *The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments (2003)* also contains information on PAHs.

5.0 - SIGNIFICANCE THRESHOLDS

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
- 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).

Note: SJAPCD is currently planning to increase the risk standard to 20 in one million theoretical excess cancer cases. However, this study is based on the current standard of 10 in one million theoretical excess cancer cases.

6.0 - HEALTH RISK ASSESSMENT RESULTS

A refined health risk assessment was performed using the HARP2 model. As shown, calculated cancer risk from drilling a 10,000' well exceeds a threshold of 10 cases in one million (Table 6). The maximum distances from the shared property boundary (oil company and private resident) are illustrated in Figure 1 below.

The 5,000' well scenario also exceeds 10 in one million in 2015 only. Therefore, after 2015, any well drilled shallower than 5,000' would not result in a risk greater than 10 in one million. (Table 6)

None of the gas fired equipment exceeds a risk of 10 in one million (Table 7).

The scenario in which all of the oil processing equipment operates full time and is located in the exact same location with a shared fenceline to private property results in a 10 in one million risk level from 478 – 701 feet depending on the subarea of Kern County (Table 7).

None of the noncancer hazards for either an oil processing facility or a gas processing facility exceed the regulatory threshold of 1.0 (Tables 9 and 10).

Figure 1 -

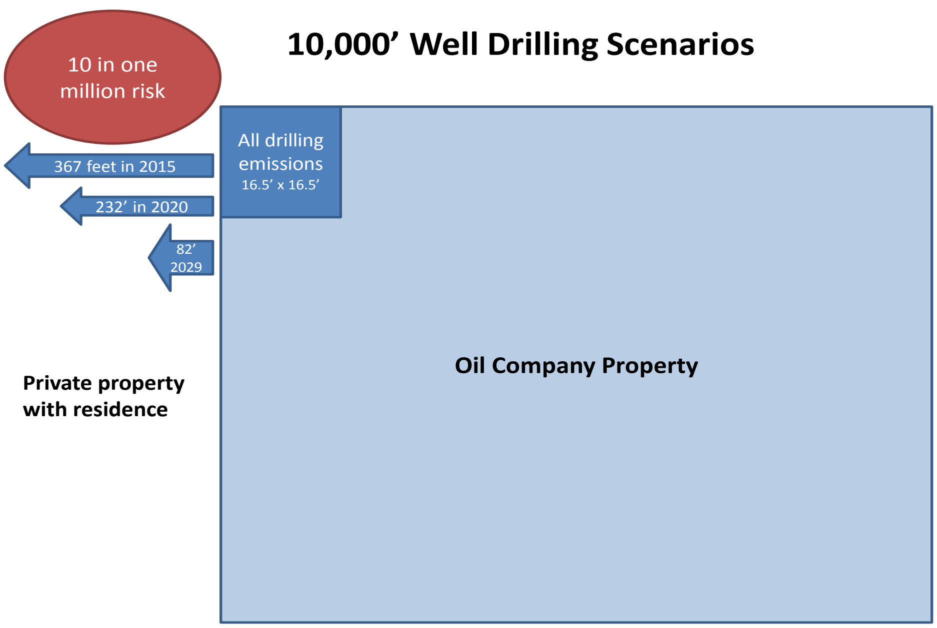

Table 6 –

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
Western Subarea		
10,000	2015	367 feet
10,000	2020	232 feet
10,000	2029	82 feet
5000	2015	116 feet
5000	2029	NA*
2000	2015	NA
2000	2029/2035	NA
Central Subarea		
10,000	2015	367 feet
10,000	2020	232 feet
10,000	2029	82 feet
5000	2015	116 feet
5000	2029	NA
2000	2015	NA
2000	2029/2035	NA
Eastern Subarea		
10,000	2015	296 feet
10,000	2019	183 feet
10,000	2029	NA
5000	2015	NA
5000	2029	NA
2000	2015	NA
2000	2029/2035	NA

*NA = no offsite risk greater than 10 in one million.

Table 7 -

Potential health risks from gas processing equipment

Equipment	**Risk greater than 10 in one million?**
1000 bhp natural gas ICE	No
100 mmbtu/hr flare	No
85 mmbtu/hour steam generator	No
8 mm btu/hour boiler	No
33 MW cogen	No
TEOR Equipment	No

Table 8 –

Potential health risks from all oil processing equipment

Equipment	**Western Subregion Cancer Risk Distance to 10 in one million***	**Central Subregion Cancer Risk Distance to 10 in one million***	**Eastern Subregion Cancer Risk Distance to 10 in one million***
1,000 bbl oil tank			
1,000 bbl oil tank			
3,000 bbl oil tank			
truck loading rack			
30'x30' sump			
10,000 btu/hour flare			
Fugitive VOCs			
TOTAL CUMULATIVE RISK Distances	701'	625'	478'

*Risk distances assume that all equipment is placed along a shared fence line between the oil site and a private residence.

NOTE: All of this equipment would require SVAPCD air permits. As such, the risk threshold must be complied with or permits cannot be issued. So, in this scenario either less equipment could be used and/or the receptors cannot share a fence line in order for this scenario to be viable.

Table 9
Potential Acute Impacts

Equipment	Western Subregion Acute Risk	Central Subregion Acute Risk	Eastern Subregion Acute Risk	Hazard Index Standard	Significant Risk?
Drilling Emissions 10,000' well	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

Table 10
Potential Chronic (Non Cancer Impacts)

Equipment	Western Subregion Chronic Risk	Central Subregion Chronic Risk	Eastern Subregion Chronic Risk	Hazard Index Standard	Significant Risk?
Drilling Emissions 10,000' well	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

7.0 - REFERENCES

California Code of Regulations, Title 22, Division 2, Chapter 3, Section 12000 "Safe Drinking Water and Toxic Enforcement Act of 1986." California regulations can be downloaded at the following link: http://www.oal.ca.gov/.

CARB. 2015. "HARP User Guide." The document can be downloaded at the following link: http://www.arb.ca.gov/toxics/harp/harpug.htm

SCAQMD. 2007. "General Instruction Book for the 2006-2007 Annual Emission Reporting Program." The document can be downloaded at the following link: http://www.ecotek.com/aqmd/2006/forms_and_instructions_pdf/0607_GuideBook.pdf

SCAQMD. 2005. "Risk Assessment Procedures for Rules 1401 and 212". The document can be downloaded at the following links: http://www.aqmd.gov/prdas/pdf/riskassessmentprocedures-v7.pdf and http://www.aqmd.gov/prdas/pdf/attachmentpkg-l.pdf.

SCAQMD. 2005. "Supplemental Guidelines for Preparing Risk Assessments for the Air Toxics "Hot Spots" Information and Assessment Act (AB2588). The document can be downloaded at the following link: http://www.aqmd.gov/prdas/AB2588/pdf/AB2588_Guidelines.pdf.

United States Environmental Protection Agency (U.S. EPA) 2004. User's Guide for the AMS/EPA Regulatory Model – AERMOD, EPA-454/B-03-001.

Meteorological data used by AERMOD was obtained by SJVAPCD for Bakersfield Station 23155.

OEHHA. 2003. "The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments." The document can be downloaded at the following link:http://www.oehha.ca.gov/air/hot_spots/HRSguide.html.

Vector Environmental: Emissions from Offroad Mobile Sources and Portable Equipment Required for the Construction of Wells. 2015. Criteria pollutant emission data by activity, phase and task for years 2012-2029.

Vector Environmental: MS Excel spreadsheet entitled: "DRL_EMISSIONS.xlsx".

Appendix A

Toxic Air Contaminants by Device

Source Name	Source ID	CAS #	Chemical Name	Pounds/year	Pounds/hour
Fugitive VOCs	FHC01	95636	"1,2,4 Trimethylbenzene"	0.01	0.00
Fugitive VOCs	FHC01	71432	Benzene	0.32	0.00
Fugitive VOCs	FHC01	110827	Cyclohexane	0.02	0.00
Fugitive VOCs	FHC01	100414	Ethylbenzene	0.10	0.00
Fugitive VOCs	FHC01	110543	n-Hexane	2.38	0.00
Fugitive VOCs	FHC01	108883	Toluene	0.36	0.00
Fugitive VOCs	FHC01	1330207	Xylenes	0.19	0.00
Fugitive VOCs	FHC01	7783064	Hydrogen sulfide	2.02	0.00
10 MMBtu/hr Flare	FLR01	75070	Acetaldehyde	3.77	0.00
10 MMBtu/hr Flare	FLR01	107028	Acrolein	0.88	0.00
10 MMBtu/hr Flare	FLR01	71432	Benzene	13.93	0.00
10 MMBtu/hr Flare	FLR01	110827	Cyclohexane	0.00	0.00
10 MMBtu/hr Flare	FLR01	100414	Ethylbenzene	126.49	0.01
10 MMBtu/hr Flare	FLR01	50000	Formaldehyde	102.40	0.01
10 MMBtu/hr Flare	FLR01	110543	n-Hexane	2.54	0.00
10 MMBtu/hr Flare	FLR01	7783064	Hydrogen sulfide	15.70	0.00
10 MMBtu/hr Flare	FLR01	91203	Naphthalene	0.96	0.00
10 MMBtu/hr Flare	FLR01	1151	PAH's	1.23	0.00
10 MMBtu/hr Flare	FLR01	115071	Propylene	213.74	0.02
10 MMBtu/hr Flare	FLR01	108883	Toluene	5.08	0.00
10 MMBtu/hr Flare	FLR01	1330207	Xylenes	2.54	0.00

Sump	SMP01	95636	"1,2,4 Trimethylbenzene"	0.23	0.00
Sump	SMP01	71432	Benzene	6.78	0.00
Sump	SMP01	110827	Cyclohexane	0.33	0.00
Sump	SMP01	100414	Ethylbenzene	2.16	0.00
Sump	SMP01	110543	n-Hexane	50.00	0.01
Sump	SMP01	108883	Toluene	7.60	0.00
Sump	SMP01	1330207	Xylenes	4.01	0.00
Sump	SMP01	7783064	Hydrogen sulfide	0.49	0.00
Truck Loading Rack	LDR01	95636	"1,2,4 Trimethylbenzene"	0.63	0.00
Truck Loading Rack	LDR01	71432	Benzene	18.92	0.00
Truck Loading Rack	LDR01	110827	Cyclohexane	0.92	0.00
Truck Loading Rack	LDR01	100414	Ethylbenzene	6.02	0.00
Truck Loading Rack	LDR01	110543	n-Hexane	139.46	0.02
Truck Loading Rack	LDR01	108883	Toluene	21.20	0.00
Truck Loading Rack	LDR01	1330207	Xylenes	11.18	0.00
Truck Loading Rack	LDR01	7783064	Hydrogen sulfide	1.36	0.00
Oil Storage Tank (1,000 bbls)	TNK03	95636	"1,2,4 Trimethylbenzene"	0.75	0.00
Oil Storage Tank (1,000 bbls)	TNK03	71432	Benzene	22.45	0.00
Oil Storage Tank (1,000 bbls)	TNK03	110827	Cyclohexane	1.10	0.00
Oil Storage Tank (1,000 bbls)	TNK03	100414	Ethylbenzene	7.15	0.00
Oil Storage Tank (1,000 bbls)	TNK03	110543	n-Hexane	165.48	0.02

Oil Storage Tank (1,000 bbls)	TNK03	108883	Toluene	25.16	0.00
Oil Storage Tank (1,000 bbls)	TNK03	1330207	Xylenes	13.26	0.00
Oil Storage Tank (1,000 bbls)	TNK03	7783064	Hydrogen sulfide	1.62	0.00
Oil Storage Tank (1,000 bbls)	TNK02	95636	"1,2,4 Trimethylbenzene"	0.75	0.00
Oil Storage Tank (1,000 bbls)	TNK02	71432	Benzene	22.45	0.00
Oil Storage Tank (1,000 bbls)	TNK02	110827	Cyclohexane	1.10	0.00
Oil Storage Tank (1,000 bbls)	TNK02	100414	Ethylbenzene	7.15	0.00
Oil Storage Tank (1,000 bbls)	TNK02	110543	n-Hexane	165.48	0.02
Oil Storage Tank (1,000 bbls)	TNK02	108883	Toluene	25.16	0.00
Oil Storage Tank (1,000 bbls)	TNK02	1330207	Xylenes	13.26	0.00
Oil Storage Tank (1,000 bbls)	TNK02	7783064	Hydrogen sulfide	1.62	0.00
Oil Storage Tank (3,000 bbls)	TNK01	95636	"1,2,4 Trimethylbenzene"	0.60	0.00
Oil Storage Tank (3,000 bbls)	TNK01	71432	Benzene	17.73	0.00
Oil Storage Tank (3,000 bbls)	TNK01	110827	Cyclohexane	0.87	0.00
Oil Storage Tank (3,000 bbls)	TNK01	100414	Ethylbenzene	5.64	0.00
Oil Storage Tank	TNK01	110543	n-Hexane	130.72	0.02

(3,000 bbls)					
Oil Storage Tank (3,000 bbls)	TNK01	108883	Toluene	19.87	0.00
Oil Storage Tank (3,000 bbls)	TNK01	1330207	Xylenes	10.48	0.00
Oil Storage Tank (3,000 bbls)	TNK01	7783064	Hydrogen sulfide	1.28	0.00
Process Heater	PHT01	83329	Acenaphthene	0.00	0.00
Process Heater	PHT01	208968	Acenaphthylene	0.01	0.00
Process Heater	PHT01	75070	Acetaldehyde	1.17	0.00
Process Heater	PHT01	107028	Acrolein	0.20	0.00
Process Heater	PHT01	120127	Anthracene	0.00	0.00
Process Heater	PHT01	56553	Benz(a)anthracene	0.00	0.00
Process Heater	PHT01	71432	Benzene	1.71	0.00
Process Heater	PHT01	50328	Benzo(a)pyrene	0.00	0.00
Process Heater	PHT01	205992	Benzo(b)fluoranthene	0.00	0.00
Process Heater	PHT01	191242	"Benzo(g,h,i)perylene"	0.00	0.00
Process Heater	PHT01	207089	Benzo(k)fluoranthene	0.00	0.00
Process Heater	PHT01	218019	Chrysene	0.00	0.00
Process Heater	PHT01	53703	"Dibenz(a,h)anthracene"	0.00	0.00
Process Heater	PHT01	206440	Fluoranthene	0.00	0.00
Process Heater	PHT01	86737	Fluorene	0.12	0.00
Process Heater	PHT01	50000	Formaldehyde	6.23	0.00
Process Heater	PHT01	7783064	Hydrogen sulfide	12.56	0.00
Process Heater	PHT01	193395	"Indeno(1,2,3-cd)pyrene"	0.00	0.00
Process Heater	PHT01	91203	Naphthalene	0.43	0.00

Process Heater	PHT01	85018	Phenanthrene	0.03	0.00
Process Heater	PHT01	108952	Phenol	0.15	0.00
Process Heater	PHT01	115071	Propylene	0.97	0.00
Process Heater	PHT01	129000	Pyrene	0.00	0.00
Process Heater	PHT01	108883	Toluene	2.12	0.00
Process Heater	PHT01	1330207	Xylenes	2.45	0.00
Steam Generator	SGR01	83329	Acenaphthene	0.00	0.00
Steam Generator	SGR01	208968	Acenaphthylene	0.01	0.00
Steam Generator	SGR01	75070	Acetaldehyde	19.88	0.00
Steam Generator	SGR01	107028	Acrolein	13.55	0.00
Steam Generator	SGR01	120127	Anthracene	0.00	0.00
Steam Generator	SGR01	56553	Benz(a)anthracene	0.00	0.00
Steam Generator	SGR01	71432	Benzene	4.62	0.00
Steam Generator	SGR01	50328	Benzo(a)pyrene	0.00	0.00
Steam Generator	SGR01	205992	Benzo(b)fluoranthene	0.00	0.00
Steam Generator	SGR01	191242	"Benzo(g,h,i)perylene"	0.00	0.00
Steam Generator	SGR01	207089	Benzo(k)fluoranthene	0.00	0.00
Steam Generator	SGR01	218019	Chrysene	0.00	0.00
Steam Generator	SGR01	53703	"Dibenz(a,h)anthracene"	0.00	0.00
Steam Generator	SGR01	100414	Ethylbenzene	13.85	0.00
Steam Generator	SGR01	206440	Fluoranthene	0.01	0.00
Steam Generator	SGR01	86737	Fluorene	0.01	0.00
Steam Generator	SGR01	50000	Formaldehyde	52.20	0.01
Steam Generator	SGR01	7783064	Hydrogen sulfide	133.42	0.02

Steam Generator	SGR01	193395	"Indeno(1,2,3-cd)pyrene"	0.00	0.00
Steam Generator	SGR01	91203	Naphthalene	0.41	0.00
Steam Generator	SGR01	85018	Phenanthrene	0.02	0.00
Steam Generator	SGR01	115071	Propylene	469.10	0.05
Steam Generator	SGR01	129000	Pyrene	0.01	0.00
Steam Generator	SGR01	108883	Toluene	22.93	0.00
Steam Generator	SGR01	1330207	Xylenes	30.01	0.00
1,000 hp ICE	ICE01	71432	Benzene	126.21	0.01
1,000 hp ICE	ICE01	50000	Formaldehyde	3118.12	0.36
1,000 hp ICE	ICE01	115071	Propylene	1187.86	0.14
1,000 hp ICE	ICE01	108883	Toluene	57.17	0.01
1,000 hp ICE	ICE01	1330207	Xylenes	28.95	0.00
1,000 hp ICE	ICE01	7783064	Hydrogen sulfide	13.30	0.00
Drilling Emissions	DRL01	9901.00	Diesel Particulate Matter	17.23	1
33 MW Cogen	COG01	71432	Benzene	36.07	0.00
33 MW Cogen	COG01	7783064	Hydrogen sulfide	442.64	0.05
33 MW Cogen	COG01	91203	Naphthalene	14.30	0.00
33 MW Cogen	COG01	1151	PAH's	0.63	0.00
33 MW Cogen	COG01	50000	Formaldehyde	454.54	0.05
Drilling Mud Sump	SMP02	95636	"1,2,4 Trimethylbenzene"	0.01	0.00
Drilling Mud Sump	SMP02	71432	Benzene	0.28	0.00
Drilling Mud Sump	SMP02	110827	Cyclohexane	0.01	0.00
Drilling Mud Sump	SMP02	100414	Ethylbenzene	0.09	0.00
Drilling Mud Sump	SMP02	110543	n-Hexane	2.10	0.00

Drilling Mud Sump	SMP02	108883	Toluene	0.32	0.00
Drilling Mud Sump	SMP02	1330207	Xylenes	0.17	0.00
Drilling Mud Sump	SMP02	7783064	Hydrogen sulfide	0.02	0.00
Boiler	BLR01	83329	Acenaphthene	0.00	0.00
Boiler	BLR01	208968	Acenaphthylene	0.00	0.00
Boiler	BLR01	75070	Acetaldehyde	2.34	0.00
Boiler	BLR01	107028	Acrolein	1.59	0.00
Boiler	BLR01	120127	Anthracene	0.00	0.00
Boiler	BLR01	56553	Benz(a)anthracene	0.00	0.00
Boiler	BLR01	71432	Benzene	0.54	0.00
Boiler	BLR01	50328	Benzo(a)pyrene	0.00	0.00
Boiler	BLR01	205992	Benzo(b)fluoranthene	0.00	0.00
Boiler	BLR01	191242	"Benzo(g,h,i)perylene"	0.00	0.00
Boiler	BLR01	207089	Benzo(k)fluoranthene	0.00	0.00
Boiler	BLR01	218019	Chrysene	0.00	0.00
Boiler	BLR01	53703	"Dibenz(a,h)anthracene"	0.00	0.00
Boiler	BLR01	100414	Ethylbenzene	1.63	0.00
Boiler	BLR01	206440	Fluoranthene	0.00	0.00
Boiler	BLR01	86737	Fluorene	0.00	0.00
Boiler	BLR01	50000	Formaldehyde	6.14	0.00
Boiler	BLR01	7783064	Hydrogen sulfide	15.70	0.00
Boiler	BLR01	193395	"Indeno(1,2,3-cd)pyrene"	0.00	0.00
Boiler	BLR01	91203	Naphthalene	0.05	0.00
Boiler	BLR01	85018	Phenanthrene	0.00	0.00

Boiler	BLR01	115071	Propylene	55.19	0.01
Boiler	BLR01	129000	Pyrene	0.00	0.00
Boiler	BLR01	108883	Toluene	2.70	0.00
Boiler	BLR01	1330207	Xylenes	3.53	0.00
Thermally Enhanced Oil Recovery Equipment	TEOR	95636	"1,2,4 Trimethylbenzene"	0.03	0.00
Thermally Enhanced Oil Recovery Equipment	TEOR	71432	Benzene	0.95	0.00
Thermally Enhanced Oil Recovery Equipment	TEOR	110827	Cyclohexane	0.05	0.00
Thermally Enhanced Oil Recovery Equipment	TEOR	100414	Ethylbenzene	0.30	0.00
Thermally Enhanced Oil Recovery Equipment	TEOR	110543	n-Hexane	6.98	0.00
Thermally Enhanced Oil Recovery Equipment	TEOR	108883	Toluene	1.06	0.00
Thermally Enhanced Oil Recovery Equipment	TEOR	1330207	Xylenes	0.56	0.00
Thermally Enhanced Oil	TEOR	7783064	Hydrogen sulfide	0.07	0.00

Recovery Equipment					
100 MMBtu/hr Flare	FLR02	75070	Acetaldehyde	37.67	0.00
100 MMBtu/hr Flare	FLR02	107028	Acrolein	8.76	0.00
100 MMBtu/hr Flare	FLR02	71432	Benzene	139.28	0.02
100 MMBtu/hr Flare	FLR02	110827	Cyclohexane	0.00	0.00
100 MMBtu/hr Flare	FLR02	100414	Ethylbenzene	1264.94	0.14
100 MMBtu/hr Flare	FLR02	50000	Formaldehyde	1024.04	0.12
100 MMBtu/hr Flare	FLR02	110543	n-Hexane	25.40	0.00
100 MMBtu/hr Flare	FLR02	7783064	Hydrogen sulfide	15.70	0.00
100 MMBtu/hr Flare	FLR02	91203	Naphthalene	9.64	0.00
100 MMBtu/hr Flare	FLR02	1151	PAH's	12.26	0.00
100 MMBtu/hr Flare	FLR02	115071	Propylene	2137.44	0.24
100 MMBtu/hr Flare	FLR02	108883	Toluene	50.81	0.01
100 MMBtu/hr Flare	FLR02	1330207	Xylenes	25.40	0.00

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Appendix B –

Equipment and Emissions for Well Depths

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2015 Emissions from a 2000 ft. Well

Construction Activity: A1. Land Preparation

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Water Truck	1.0	7.0	8.48	400	3.46
Loader	1.0	4.0	2.5	100	.34
35 Yard Dump Truck	1.0	2 .0	1.00	400	.12
Grader	1.0	4.0	2.5	175	.77
Skip & Scrap (Backhoe)	1.0	1.0	1.0	100	.03
Big Scrapper	1.0	2.0	2.5	362	.47
Dozer (D9R)	1.0	1.0	1.0	255	.08
Low Bed Truck/Trailer	1.0	2.0	.5	400	.06
Dump Truck 10 Wheels	1.0	1.0	.5	400	.03
Backhoe	1.0	2.0	.54	100	.04
Loader	1.0	3.0	2.5	100	.26
Loader	1.0	2.0	1.0	100	.07
Escavator (Backoe/tracks)	1.0	1.0	1.0	163	.03
Dozer (D8T)	1.0	1.0	1.0	255	.08
End Dump Truck & Trailer	1.0	1.0	.50	400	.03
Grader	1.0	1.0	.50	175	.04
Annual Emissions From Offroad Source Activity					5.91

2015 Emissions from a 2000 Ft. Well

Construction Activity: B.1 Drilling Survey

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Rig	1.0	1.0	12.00	100	.58
Cement Truck	1.0	4.0	12.00	400	.70
Annual Emissions From Offroad Source Activity					1.28

2015 Emission from a 2000 Ft. Well

Construction Activity: C.1 Well Drilling

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Crane	1.0	2.0	8.00	230	.81
Port Light Stands	5.0	5.0	12.00	20	2.41
Portable Gen. Hydraulic Power	1.0	5.0	22.00	80	3.66
Portable Gen. DSM/Trailers	2.0	5.0	24.00	100	9.99
Portable Gen. Mud Separator	1.0	4.0	22.00	420	4.65
Rotary Table or Top Drive	1.0	4.0	22.00	135	5.63
Diesel Engine For Hoist	1.0	4.0	22.00	455	6.74
Diesel Engine For Hoist	1.0	4.0	22.0	442	6.55
Diesel Engine for Mud Pump	1.0	4.0	22.00	424	6.28
Annual Emissions From Offroad Source Activity					46.72

2015 Emissions from a 2000 Ft Well

Construction Activity: D.1 Well Completion

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Accumulator Generator	1.0	4.0	24.00	100	4.0
Filter Skid (Pump)	1.0	2.0	3.00	90	.22
Acid Pump #1 (Hydraulic Oil Pump)	1.0	1.0	22.00	175	.85
Acid Pump #2 (Acid Fluid Pumping)	1.0	4.0	22.00	765	2.17
Generator for Doghouse for WO Rig	1.0	4.0	24.00	70	2.8
3 Light Plants for WO Rig	3.0	4.0	12.00	20	1.15
Diesel Engine for COROD or Other	1.0	1.0	22.00	450	1.67
Portable Den. Mud Separator	1.0	4.0	22.00	420	4.65
Rotary Table or Top Drive	1.0	4.0	22.00	135	5.63
Diesel Engine for Hoist	1.0	4.0	22.00	455	6.74
Diesel Engine for Hoist	1.0	3.0	22.00	442	6.55
Diesel Engine for Mud Pump	1.0	4.0	22.00	424	6.28
Annual Emissions From Offroad Source Activity (Lb/Year)					42.71

2015 Emissions from a 2000 Ft. Well Construction Activity: E.1 Well Flowline

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Side Boom D4/Crawler	1.0	3.0	10.00	520	.92
Backhoe	1.0	3.0	10.00	95	.98
Pipe Fitting or Welders	1.0	3.0	10.00	40	.48
Hydrotest Pump	1.0	1.0	1.00	.08	.01
Forklift	1.0	3.0	10.00	125	.56
Other Equipment/Bending Machine	1.0	3.0	10.00	80	1.12
Annual Emissions From Offroad Source Activity					4.07

2015 Emissions from a 2000 Ft. Well

Construction Activity: F.1 Pump Unit

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Power Generator	1.0	2.0	8.00	10	.06
Backhoe	1.0	2.0	4.00	80	.22
Welder	1.0	2.0	8.00	25	.16
Annual Emissions From Offroad Source Activity					.44

2015 Emissions from a 2000 Ft. Well Construction Activity: G.1 Electrical

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Line Truck	1.0	4.0	10.00	250	1.73
Bucket Truck	1.0	4.0	10.00	250	1.73
Electrical Service Truck	1.0	4.0	1.00	300	.15
Power Generators	1.0	4.0	1.00	10	.02
Back-Hoe	1.0	1.0	10.00	650	.80
Annual Emissions From Offroad Source Activity					4.43

2015 Emissions from a 5000 ft. Well

Construction Activity: A1. Land Preparation

2015 Emissions from a 5000 Ft. Well

Construction Activity: B.1 Drilling Survey

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Rig	1.0	1.0	12.00	100	.58
Cement Truck	1.0	1.0	12.00	400	.70
Annual Emissions From Offroad Source Activity (Lb/Year					1.28

2015 Emission from a 5000 Ft. Well Construction Activity: C.1 Well Drilling

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Crane	1.0	2.0	8.00	230	.81
Port Light Stands	5.0	9.0	12.00	20	4.33
Portable Gen. Hydraulic Power	1.0	9.0	22.00	80	6.60
Portable Gen. DSM/Trailers	2.0	9.0	24.00	100	17.99
Portable Gen. Mud Separator	1.0	8.0	22.00	420	9.30
Rotary Table or Top Drive	1.0	8.0	22.00	135	11.26
Diesel Engine For Hoist	1.0	8.0	22.00	455	13.48
Diesel Engine For Hoist	1.0	8.0	22.0	442	13.09
Diesel Engine for Mud Pump	1.0	8.0	22.00	424	12.56
Annual Emissions From Offroad Source Activity					89.42

2015 Emissions from a 5000 Ft Well

Construction Activity: D.1 Well Completion

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Accumulator Generator	1.0	8.0	24.00	100	8.00
Filter Skid (Pump)	1.0	2.0	3.00	90	.22
Acid Pump #1 (Hydraulic Oil Pump)	1.0	1.0	22.00	175	.85
Acid Pump #2 (Acid Fluid Pumping)	1.0	1.0	22.00	765	2.17
Generator for Doghouse for WO Rig	1.0	8.0	24.00	70	5.60
3 Light Plants for WO Rig	3.0	8.0	12.00	20	2.31
Diesel Engine for COROD or Other	1.0	1.0	22.00	450	1.67
Portable Den. Mud Separator	1.0	8.0	22.00	420	9.30
Rotary Table or Top Drive	1.0	8.0	22.00	135	11.26
Diesel Engine for Hoist	1.0	8.0	22.00	455	13.48
Diesel Engine for Hoist	1.0	8.0	22.00	442	13.09
Diesel Engine for Mud Pump	1.0	8.0	22.00	424	12.56
Annual Emissions From Offroad Source Activity (Lb/Year)					80.51

2015 Emissions from a 5000 Ft. Well

Construction Activity: E.1 Well Flowline

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Side Boom D4/Crawler	1.0	3.0	10.00	520	.92
Backhoe	1.0	3.0	10.00	95	.98
Pipe Fitting or Welders	1.0	3.0	10.00	40	.48
Hydrotest Pump	1.0	1.0	1.00	.08	.01
Forklift	1.0	3.0	10.00	125	.56
Other Equipment/Bending Machine	1.0	3.0	10.00	80	1.12
Annual Emissions From Offroad Source Activity					4.07

2015 Emissions from a 5000 Ft. Well

Construction Activity: F.1 Pump Unit

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Power Generator	1.0	2.0	8.00	10	.06
Backhoe	1.0	2.0	4.00	80	.22
Welder	1.0	2.0	8.00	25	.16
Annual Emissions From Offroad Source Activity					.44

2015 Emissions from a 5000 Ft. Well

Construction Activity: G.1 Electrical

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Line Truck	1.0	4.0	10.00	250	1.73
Bucket Truck	1.0	4.0	10.00	250	1.73
Electrical Service Truck	1.0	4.0	1.00	300	.15
Power Generators	1.0	4.0	1.00	10	.02
Back-Hoe	1.0	1.0	10.00	650	.80
Annual Emissions From Offroad Source Activity					4.43

2015 Emissions from a 5000 ft. Well

Construction Activity: A1. Land Preparation

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Water Truck	1.0	7.0	8.48	400	3.46
Loader	1.0	4.0	2.5	100	.34
35 Yard Dump Truck	1.0	2 .0	1.00	400	.12
Grader	1.0	4.0	2.5	175	.77
Skip & Scrap (Backhoe)	1.0	1.0	1.0	100	.03
Big Scrapper	1.0	2.0	2.5	362	.47
Dozer (D9R)	1.0	1.0	1.0	255	.08
Low Bed Truck/Trailer	1.0	2.0	.5	400	.06
Dump Truck 10 Wheels	1.0	1.0	.5	400	.03
Backhoe	1.0	2.0	.54	100	.04
Loader	1.0	3.0	2.5	100	.26
Loader	1.0	2.0	1.0	100	.07
Escavator (Backoe/tracks)	1.0	1.0	1.0	163	.03
Dozer (D8T)	1.0	1.0	1.0	255	.08
End Dump Truck & Trailer	1.0	1.0	.50	400	.03
Grader	1.0	1.0	.50	175	.04
Annual Emissions From Offroad Source Activity (Lb/Year)					5.91

2015 Emissions from a 5000 Ft. Well

Construction Activity: B.1 Drilling Survey

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Rig	1.0	1.0	12.00	100	.58
Cement Truck	1.0	1.0	12.00	400	.70
Annual Emissions From Offroad Source Activity (Lb/Year					1.28

2015 Emission from a 5000 Ft. Well

Construction Activity: C.1 Well Drilling

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Crane	1.0	2.0	8.00	230	.81
Port Light Stands	5.0	9.0	12.00	20	4.33
Portable Gen. Hydraulic Power	1.0	9.0	22.00	80	6.60
Portable Gen. DSM/Trailers	2.0	9.0	24.00	100	17.99
Portable Gen. Mud Separator	1.0	8.0	22.00	420	9.30
Rotary Table or Top Drive	1.0	8.0	22.00	135	11.26
Diesel Engine For Hoist	1.0	8.0	22.00	455	13.48
Diesel Engine For Hoist	1.0	8.0	22.0	442	13.09
Diesel Engine for Mud Pump	1.0	8.0	22.00	424	12.56
Annual Emissions From Offroad Source Activity					89.42

2015 Emissions from a 5000 Ft Well

Construction Activity: D.1 Well Completion

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Accumulator Generator	1.0	8.0	24.00	100	8.00
Filter Skid (Pump)	1.0	2.0	3.00	90	.22
Acid Pump #1 (Hydraulic Oil Pump)	1.0	1.0	22.00	175	.85
Acid Pump #2 (Acid Fluid Pumping)	1.0	1.0	22.00	765	2.17
Generator for Doghouse for WO Rig	1.0	8.0	24.00	70	5.60
3 Light Plants for WO Rig	3.0	8.0	12.00	20	2.31
Diesel Engine for COROD or Other	1.0	1.0	22.00	450	1.67
Portable Den. Mud Separator	1.0	8.0	22.00	420	9.30
Rotary Table or Top Drive	1.0	8.0	22.00	135	11.26
Diesel Engine for Hoist	1.0	8.0	22.00	455	13.48
Diesel Engine for Hoist	1.0	8.0	22.00	442	13.09
Diesel Engine for Mud Pump	1.0	8.0	22.00	424	12.56
Annual Emissions From Offroad Source Activity (Lb/Year)					80.51

2015 Emissions from a 5000 Ft. Well

Construction Activity: E.1 Well Flowline

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Side Boom D4/Crawler	1.0	3.0	10.00	520	.92
Backhoe	1.0	3.0	10.00	95	.98
Pipe Fitting or Welders	1.0	3.0	10.00	40	.48
Hydrotest Pump	1.0	1.0	1.00	.08	.01
Forklift	1.0	3.0	10.00	125	.56
Other Equipment/Bending Machine	1.0	3.0	10.00	80	1.12
Annual Emissions From Offroad Source Activity					4.07

2015 Emissions from a 5000 Ft. Well

Construction Activity: F.1 Pump Unit

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Power Generator	1.0	2.0	8.00	10	.06
Backhoe	1.0	2.0	4.00	80	.22
Welder	1.0	2.0	8.00	25	.16
Annual Emissions From Offroad Source Activity					.44

2015 Emissions from a 5000 Ft. Well

Construction Activity: G.1 Electrical

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Line Truck	1.0	4.0	10.00	250	1.73
Bucket Truck	1.0	4.0	10.00	250	1.73
Electrical Service Truck	1.0	4.0	1.00	300	.15
Power Generators	1.0	4.0	1.00	10	.02
Back-Hoe	1.0	1.0	10.00	650	.80
Annual Emissions From Offroad Source Activity					4.43

2029/2035 Emissions from a 5000 ft. Well

Construction Activity: A1. Land Preparation

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Water Truck	1.0	7.0	8.48	400	.58
Loader	1.0	4.0	2.5	100	.04
35 Yard Dump Truck	1.0	2 .0	1.00	400	.02
Grader	1.0	4.0	2.5	175	.15
Skip & Scrap (Backhoe)	1.0	1.0	1.0	100	.00
Big Scrapper	1.0	2.0	2.5	362	.11
Dozer (D9R)	1.0	1.0	1.0	255	.03
Low Bed Truck/Trailer	1.0	2.0	.5	400	.01
Dump Truck 10 Wheels	1.0	1.0	.5	400	.00
Backhoe	1.0	2.0	.54	100	.00
Loader	1.0	3.0	2.5	100	.03
Loader	1.0	2.0	1.0	100	.01
Escavator (Backoe/tracks)	1.0	1.0	1.0	163	.01
Dozer (D8T)	1.0	1.0	1.0	255	.03
End Dump Truck & Trailer	1.0	1.0	.50	400	.00
Grader	1.0	1.0	.50	175	.01
Annual Emissions From Offroad Source Activity (Lb/Year)					1.03

2029/2035 Emissions from a 5000 Ft. Well Construction Activity: B.1 Drilling Survey

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Rig-Truck Mounted	1.0	1.0	12.00	100	.58
Cement Truck-Cement Mousehole	1.0	1.0	12.00	400	.12
Annual Emissions From Offroad Source Activity (Lb/Year)					.70

2029/2035 Emission from a 5000 Ft. Well

Construction Activity: C.1 Well Drilling

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Crane	1.0	2.0	8.00	230	.19
Port Light Stands	5.0	9.0	12.00	20	.60
Portable Gen. Hydraulic Power	1.0	9.0	22.00	80	.86
Portable Gen. DSM/Trailers	2.0	9.0	24.00	100	2.35
Portable Gen. Mud Separator	1.0	8.0	22.00	420	1.37
Rotary Table or Top Drive	1.0	8.0	22.00	135	.74
Diesel Engine For Hoist	1.0	8.0	22.00	455	4.11
Diesel Engine For Hoist	1.0	8.0	22.00	442	3.99
Diesel Engine for Mud Pump	1.0	8.0	22.00	424	3.83
Annual Emissions From Offroad Source Activity (Lb/Year)					18.04

2029/2035 Emissions from a 5000 Ft Well

Construction Activity: D.1 Well Completion

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Accumulator Generator	1.0	8.0	24.00	100	1.04
Filter Skid (Pump)	1.0	2.0	3.00	90	.03
Acid Pump #1 (Hydraulic Oil Pump)	1.0	1.0	22.00	175	.12
Acid Pump #2 (Acid Fluid Pumping)	1.0	1.0	22.00	765	1.01
Generator for Doghouse for WO Rig	1.0	8.0	24.00	70	.73
3 Light Plants for WO Rig	3.0	8.0	12.00	20	.32
Diesel Engine for COROD or Other	1.0	1.0	22.00	450	.51
Portable Den. Mud Separator	1.0	8.0	22.00	420	1.37
Rotary Table or Top Drive	1.0	8.0	22.00	135	.74
Diesel Engine for Hoist	1.0	8.0	22.00	455	4.11
Diesel Engine for Hoist	1.0	8.0	22.00	442	3.99
Diesel Engine for Mud Pump	1.0	8.0	22.00	424	3.83
Annual Emissions From Offroad Source Activity (Lb/Year)					17.80

2029/2035 Emissions from a 5000 Ft. Well

Construction Activity: E.1 Well Flowline

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Side Boom D4/Crawler	1.0	3.0	10.00	520	.15
Backhoe	1.0	3.0	10.00	95	.12
Pipe Fitting or Welders	1.0	3.0	10.00	40	.07
Hydrotest Pump	1.0	1.0	1.00	.08	.00
Forklift	1.0	3.0	10.00	125	.08
Other Equipment/Bending Machine	1.0	3.0	10.00	80	.31
Annual Emissions From Offroad Source Activity					.73

2029/2035 Emissions from a 5000 Ft. Well

Construction Activity: F.1 Pump Unit

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Power Generator	1.0	2.0	8.00	10	.01
Backhoe	1.0	2.0	4.00	80	.03
Welder	1.0	2.0	8.00	25	.02
Annual Emissions From Offroad Source Activity					.06

2029/2035 Emissions from a 5000 Ft. Well Construction Activity: G.1 Electrical

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Line Truck	\1.0	4.0	10.00	250	.20
Bucket Truck	1.0	4.0	10.00	250	.20
Electrical Service Truck	1.0	4.0	1.00	300	.02
Power Generators	1.0	4.0	1.00	10	.00
Back-Hoe	1.0	1.0	10.00	650	.19
Annual Emissions From Offroad Source Activity					.61

2015 Emissions from a 10,000’ Well
Construction Activity: A1. Land Preparation

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Water Truck	1.0	7.0	8.48	400	3.46
Loader	1.0	4.0	2.50	100	0.34
35 Yard Dump Truck	1.0	2.0	1.00	400	0.12
Grader	1.0	4.0	2.50	175	0.77
Skip & Scrap (Backhoe)	1.0	1.0	1.00	100	0.03
Big Scrapper	1.0	2.0	2.50	362	0.47
Dozer (D9R)	1.0	1.0	1.00	255	0.08
Low Bed Truck/Trailer	1.0	2.0	0.50	400	0.06
Dump Truck 10 Wheels	1.0	1.0	0.50	400	0.03
Backhoe	1.0	2.0	0.54	100	0.04
Loader	1.0	3.0	2.50	100	0.26
Loader	1.0	2.0	1.00	100	0.07
Escavator (Backoe/tracks)	1.0	1.0	1.00	163	0.03
Dozer (D8T)	1.0	1.0	1.00	255	0.08
End Dump Truck & Trailer	1.0	1.0	0.50	400	0.03
Grader	1.0	1.0	0.50	175	0.04
Annual Emissions From Offroad Source Activity (Lb/Year)					5.91

2015 Emissions from a 10,000 Ft. Well

Construction Activity: B.1 Drilling Survey

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Rig	1.0	1.0	12.00	100	0.58
Cement Truck	1.0	1.0	12.00	400	0.70
Annual Emissions From Offroad Source Activity (Lb/Year)					1.28

2010 Emission from a 10,000 Ft. Well

Construction Activity: C.1 Well Drilling

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Crane	1.0	2.0	8.00	230	0.81
Port Light Stands	5.0	24.0	12.00	20	11.55
Portable Gen. Hydraulic Power	1.0	24.0	22.00	80	17.59
Portable Gen. DSM/Trailers	2.0	24.0	24.00	100	47.97
Portable Gen. Mud Separator	1.0	23.0	22.00	420	26.75
Rotary Table or Top Drive	1.0	23.0	22.00	144	34.52
Diesel Engine For Hoist	1.0	23.0	22.00	996	88.93
Diesel Engine For Hoist	1.0	23.0	22.00	981	87.59
Diesel Engine for Mud Pump	1.0	23.0	22.00	1145	102.23
Annual Emissions From Offroad Source Activity (Lb/Year)					417.94

2015 Emissions from a 10,000 Ft Well

Construction Activity: D.1 Well Completion

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Accumulator Generator	1.0	13.0	24.00	100	12.99
Filter Skid (Pump)	1.0	2.0	3.00	90	0.22
Acid Pump #1 (Hydraulic Oil Pump)	1.0	1.0	22.00	175	0.85
Acid Pump #2 (Acid Fluid Pumping)	1.0	1.0	22.00	765	2.017
Generator for Doghouse for WO Rig	1.0	13.0	24.00	70	9.10
3 Light Plants for WO Rig	3.0	13.0	12.00	20	3.75
Diesel Engine for COROD or Other	1.0	1.0	22.00	450	1.67
Portable Den. Mud Separator	1.0	13.0	22.00	420	15.12
Rotary Table or Top Drive	1.0	13.0	22.00	135	18.29
Diesel Engine for Hoist	1.0	13.0	22.00	455	21.90
Diesel Engine for Hoist	1.0	13.0	22.00	442	21.28
Diesel Engine for Mud Pump	1.0	13.0	22.00	424	20.41
Annual Emissions From Offroad Source Activity (Lb/Year)					127.75

2015 Emissions from a 10,000 Ft. Well

Construction Activity: E.1 Well Flowline

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Side Boom D4/Crawler	1.0	3.0	10.00	520	0.92
Backhoe	1.0	3.0	10.00	95	0.98
Pipe Fitting or Welders	1.0	3.0	10.00	40	0.48
Hydrotest Pump	1.0	1.0	1.00	20	0.01
Forklift	1.0	3.0	10.00	125	0.56
Other Equipment/Bending Machine	1.0	3.0	10.00	80	1.12
Annual Emissions From Offroad Source Activity (Lb/Year)					4.07

2015 Emissions from a 10,000 Ft. Well

Construction Activity: F.1 Pump Unit

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Power Generator	1.0	2.0	8.00	10	0.06
Backhoe	1.0	2.0	4.00	80	0.22
Welder	1.0	2.0	8.00	25	0.16
Annual Emissions From Offroad Source Activity (Lb/Year)					0.44

2015 Emissions from a 10,000 Ft. Well Construction Activity: G.1 Electrical

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Line Truck	1.0	4.0	10.00	250	1.73
Bucket Truck	1.0	4.0	10.00	250	1.73
Electrical Service Truck	1.0	4.0	1.00	300	0.15
Power Generators	1.0	4.0	1.00	10	0.02
Back-Hoe	1.0	1.0	10.00	650	0.80
Annual Emissions From Offroad Source Activity (Lb/Year)					4.43

2029/2035 Emissions from a 10,000 Ft. Well

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Water Truck	1.0	7.0	8.48	400	0.58
Loader	1.0	4.0	2.50	100	0.04
35 Yard Dump Truck	1.0	2.0	1.00	400	0.02
Grader	1.0	4.0	2.50	175	0.15
Skip & Scrap (Backhoe)	1.0	1.0	1.00	100	0.00
Big Scrapper	1.0	2.0	2.50	362	0.11
Dozer (D9R)	1.0	1.0	1.00	255	0.03
Low Bed Truck/Trailer	1.0	2.0	0.50	400	0.01
Dump Truck 10 Wheels	1.0	1.0	0.50	400	0.00
Backhoe	1.0	2.0	0.54	100	0.00
Loader	1.0	3.0	2.50	100	0.03
Loader	1.0	2.0	1.00	100	0.01
Escavator (Backoe/tracks)	1.0	1.0	1.00	163	0.01
Dozer (D8T)	1.0	1.0	1.00	255	0.03
End Dump Truck & Trailer	1.0	1.0	0.50	400	0.00
Grader	1.0	1.0	0.50	175	0.01
Annual Emissions From Offroad Source Activity (Lb/Year)					1.03

Construction Activity: A.1 Land Preparation

2029/2035 Emissions from a 10,000 Ft. Well

Construction Activity: B.1 Drilling Survey

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Rig	1.0	1.0	12.00	100	0.58
Cement Truck	1.0	1.0	12.00	400	0.12
Annual Emissions From Offroad Source Activity (Lb/Year)					0.70

2029/2035 Emission from a 10,000 Ft. Well

Construction Activity: C.1 Well Drilling

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Crane	1.0	2.00	8.00	230	0.19
Port Light Stands	5.0	24.0	12.00	20	1.61
Portable Gen. Hydraulic Power	1.0	24.0	22.00	80	2.30
Portable Gen. DSM/Trailers	2.0	24.0	24.00	100	6.27
Portable Gen. Mud Separator	1.0	23.0	22.00	420	3.94
Rotary Table or Top Drive	1.0	23.0	22.00	144	2.28
Diesel Engine For Hoist	1.0	23.0	22.00	996	37.47
Diesel Engine For Hoist	1.0	23.0	22.00	981	36.90
Diesel Engine for Mud Pump	1.0	23.0	22.00	1145	43.07
Annual Emissions From Offroad Source Activity (Lb/Year)					134.03

2029/2035 Emissions from a 10,000 Ft Well

Construction Activity: D.1 Well Completion

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Accumulator Generator	1.0	13.0	24.00	100	1.70
Filter Skid (Pump)	1.0	2.0	3.00	90	0.03
Acid Pump #1 (Hydraulic Oil Pump)	1.0	1.0	22.00	175	0.12
Acid Pump #2 (Acid Fluid Pumping)	1.0	1.0	22.00	765	1.01
Generator for Doghouse for WO Rig	1.0	13.0	24.00	70	1.19
3 Light Plants for WO Rig	3.0	13.0	12.00	20	0.52
Diesel Engine for COROD or Other	1.0	1.0	22.00	450	0.51
Portable Den. Mud Separator	1.0	13.0	22.00	420	2.22
Rotary Table or Top Drive	1.0	13.0	22.00	135	1.21
Diesel Engine for Hoist	1.0	13.0	22.00	455	6.67
Diesel Engine for Hoist	1.0	13.0	22.00	442	6.48
Diesel Engine for Mud Pump	1.0	13.0	22.00	424	6.22
Annual Emissions From Offroad Source Activity (Lb/Year)					27.88

2029/2035 Emissions from a 10,000 Ft. Well

Construction Activity: E.1 Well Flowline

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Side Boom D4/Crawler	1.0	3.0	10.00	520	0.15
Backhoe	1.0	3.0	10.00	95	0.12
Pipe Fitting or Welders	1.0	3.0	10.00	40	0.07
Hydrotest Pump	1.0	1.0	1.00	20	0.00
Forklift	1.0	3.0	10.00	125	0.08
Other Equipment/Bending Machine	1.0	3.0	10.00	80	0.31
Annual Emissions From Offroad Source Activity (Lb/Year)					0.73

2029/2035 Emissions from a 10,000 Ft. Well

Construction Activity: F.1 Pump Unit

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Power Generator	1.0	2.0	8.00	10	0.01
Backhoe	1.0	2.0	4.00	80	0.03
Welder	1.0	2.0	8.00	25	0.02
Annual Emissions From Offroad Source Activity (Lb/Year)					0.06

2029/2035 Emissions from a 10,000 Ft. Well

Construction Activity: G.1 Electrical

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Line Truck	1.0	4.0	10.00	250	0.20
Bucket Truck	1.0	4.0	10.00	250	0.20
Electrical Service Truck	1.0	4.0	1.00	300	0.02
Power Generators	1.0	4.0	1.00	10	0.00
Back-Hoe	1.0	1.0	10.00	650	0.19
Annual Emissions From Offroad Source Activity (Lb/Year)					0.61

Appendix B-1

Supplemental Health Risk Assessment Technical Memorandum (October 2020)

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Technical Memorandum on Health Risk Assessments

Kern County Draft Supplemental Recirculated Environmental Impact Report for Revisions to the Kern County Zoning Ordinance – 2020A, Oil and Gas Local Permitting

Prepared by:

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October 2020

Overview

In 2015, Environmental Compliance Solutions, Inc. completed numerous air quality health risk assessments (HRAs) for various well drilling scenarios in Kern County as part of a draft CEQA assessment prepared to evaluate potential impacts associated with *Proposed Amendments to Title 19- Kern County Zoning Ordinance – Chapter 19.98 for Oil and Gas Local Permitting*.

As a general overview, the 2015 FEIR included numerous single well HRAs which included well drilling and on-site processing and production equipment (See Appendix M of the 2015 DEIR). Well drilling was assumed to involve seven different construction phases which are included again here as Appendix A.

As part of the 2015 Final Environmental Impact Report (FEIR) prepared for the proposed Amendment to Title 19 – Kern County Zoning Ordinance – Chapter 19.98 for Oil and Gas Local Permitting, a multi-well HRA was also included. This HRA (Technical Appendix M-2) assumed that 48 wells could all be drilled simultaneously within 1 mile of a sensitive receptor. In addition to including the seven construction phases included in Appendix A below, emissions from well rework and drilling sumps were also included.

All HRAs were completed by following California guidelines and utilized all required regulatory models.

The multi-well HRA assumed 48 wells would be drilled in concentric circles around a sensitive receptor. Although 48 wells cannot be drilled and completed simultaneously, that scenario was assumed for illustrative purposes. The results of the multi-well HRA demonstrated that even if it was possible to drill 48 wells in concentric circles in distances of up to a mile around a sensitive receptor, the resulting risk calculated would be 9.3 in one million; significantly below the threshold of 20 in one million established by the San Joaquin Valley Air Pollution Control District (SJVAPCD) for use in permitting and CEQA documents.

All modeling input assumptions, documentation and modeling files were submitted to and reviewed by SJVAPCD.

This technical memorandum has been prepared to address the assumptions, modeling, and conclusions in the multi-well HRA.

Updates to HRA Modeling since 2015

ECS completed a review of all modeling changes/updates that have been made to HRA guidelines and requirements since 2015. A summary of our findings is included in Appendix B below.

The California Air Resources Board (CARB) publishes a model (OFFROAD) which summarizes criteria pollutant emission rates (including PM10) from all off-road engines in the state. This program was used to calculate diesel emission estimates used to prepare the 2015 HRAs.

Since 2015, CARB has revised their OFFROAD model. The current version of the program shows a reduction in diesel exhaust from off-road engines of approximately 48% in California since 2015. Therefore, if the HRAs were re-run in 2020, the previously calculated risk results from 2015 would be expected to reduce by almost half.

Thus, merely based on the change in assumptions regarding diesel exhaust, if the multi-well HRA were to be remodeled today, resulting risk would be approximately 4.84 in one million. This is significantly below the SJVAPCD health risk threshold of 20 in one million.

HRA Analysis

HRA Assumptions

The multi-well HRA included a very conservative scenario which modeled 48 13,00-foot wells, 12 located 1/8 of one mile away from a sensitive receptor, 12 located ¼ of a mile away, 12 located ¾ of a mile away and 12 located one mile away. This density of wells is within information stating that between 3-633 wells could "fit" within one square mile. Because, as described below, the risk driver for the HRA is drilling, what matters for density is not how many wells could be located in close proximity to each other but how many could be drilled in close proximity over a short period of time (such that the same sensitive receptor would be affected by their emissions).

Forty-eight wells cannot feasibly be drilled at the same time, or even that close in time, in Kern County as there have historically been between 4 to 12 drill rigs in the County and, since April 2020, there have only been 3 to 4 drill rigs in the County (Baker Hughes 2020). As it takes approximately 53 days to drill a 13,000-foot well, it would take 8 rigs drilling consecutively for almost a year all in one location in order to drill forty-eight 13,000 foot wells. Given that recently there have only been 3 to 4 drill rigs operating in Kern County, that this number is unlikely to increase in the near future given oil and gas production activities, and that this scenario would require all 8 of the theoretical rigs to be drilling in the same place for an entire year, jettisoning drilling throughout the rest of the County, the assumed scenario is extremely conservative.

In addition, while there may be areas of Kern County where well density is high, these may be locations where there are no sensitive receptors near to these wells. Further, less than five percent of all wells in Kern County are greater than 13,000 feet. Even with all of these very conservative assumptions, the multi-well HRA indicated a potential calculated risk value of 9.3 in one million. This is significantly below the air district's 20 in one million standard, the adopted standard of the expert agency on air quality in the Project region.

In the HRA it was assumed that the sensitive receptor had a 300m x 300m (or approximately 1,000 foot fence around it). This may have resulted in slightly different measurements of distance from the wells to the sensitive receptor in various calculations. The third ring of 12 wells was actually closer to the sensitive receptor than stated in the text and the final 12 rings are exactly as stated in the text. Slight differences in distances with respect to 24 of the 48 wells would not be expected to alter the results presented.

All particulate matter 10 microns in diameter and smaller (PM10) was considered to be toxic DPM and all diesel exhaust used in the HRA was assumed to be inhalable, a conservative assumption. Approximately 9% of DPM or diesel exhaust may not be inhalable. Therefore, this was a conservative assumption which overstated potential calculated risks. [CARB Fact Sheet: *Inhalable Particulate Matter and Health (PM2.5 and PM10*) ww2.arb.ca.gov]

The HRA annualized emissions for some Project activities, such as well rework (which assumed the need for a 500 hp Tier 2 diesel engine every other year for 9 hours and 30 minutes each time), as that is likely to occur during the day. Therefore, annualized emissions could potentially overstate calculated risk as nighttime meteorology is typically characterized by low wind speeds and stable atmospheric conditions resulting in higher modeled concentrations. During the day, the atmosphere would generally be less stable with higher wind speeds and therefore, there could be more dispersion resulting in lowered modeled concentrations. Thus, annualized emissions do not underestimate exposure impacts, but instead represent a conservative assumption of Project health risks. In addition, the assumption of well workover being conducted every other year was also conservative and likely overstates risk.

It is true that the "modeled emission rate (1 g/s) is multiplied by the worst case potential emission rate for each substance to obtain ground level concentrations." All methodologies and inputs to the HRA (including all production-related equipment) were reviewed and verified by the SJVAPCD. They requested minor adjustments which were incorporated into the final 2015 single-well HRA (Appendix M of the 2015 FEIR). The SJVAPCD also approved and confirmed the methodology used to complete each of the 2015 HRAs.

In the single-well HRAs, which included production-related equipment, multi-pathway exposure was used (including adding ingestion at the request of the air district although not part of the normal HRA procedures). For the multi-well HRA, inhalation is overwhelmingly the dominant pathway for exposure to and potential risk from diesel exhaust and thus multi-pathway exposure was not necessary.

While the multi-well HRA does not address chronic or acute impacts of cumulative well drilling and cancer risk is not the only toxic endpoint that could be considered, DPM results in approximately 99.9 percent of the risk associated with the multi-well scenario. Acute and chronic risk results are included in the "single well with production equipment" scenarios. 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 standard of 1. Isopleth maps are not required to be included in HRAs and, in this case, because they were hypothetical example locations which already included sensitive receptors and homes nearby, an isopleth would not be informative. Generally, isopleths are used to demonstrate specific concentration levels and associated risk results to a specific neighborhood.

Hazardous VOCs, including benzene emissions are included in the multi-well analysis as potentially part of drilling muds. It was also included as part of the single well HRAs with operational equipment. None of the other compounds mentioned (crystalline silica, radionuclides, radon, and trimethylsilanol) are regulated as carcinogens in California and thus they are not required to be addressed in HRAs. [OEHHA Table, August 2020]

Hazardous Air Pollutant (HAP) VOCs associated with well construction operations, production equipment and sumps were included in all HRAs. We cannot comment on the EPA estimate that 8.14 tons of VOCs would be released during a 3-day drilling event. That estimate of 5,427 pounds of VOC emissions in one day from well drilling appears to be in error. HRA emission calculations contained in these CEQA documents were derived from air district, CARB and EPA-approved emission factors including, but not limited to: EPA's TANKS program, EPA's AP-42: Compilation of Air Emissions Factors, and SJVAPCD regulatory limits. Flare emission factors were provided by SJVAPCD. Diesel exhaust emission factors were provided by CARB's OFF-ROAD model.

HAP emission factors are included in the appendix to the SREIR (Volume 2).

Diesel exhaust (not VOC-HAPs) represent 99.9 percent of the risk calculated in the multi-well HRA. SJVAPCD reviewed and approved the HRA and all associated emission factors used

We are unaware of any studies showing that methane can convert to formaldehyde in the upper atmosphere. There is some current research regarding conversion of methane to formaldehyde through the use of high temperature catalysts [*Methane Activation by Heterogeneous Catalysts*, Raiumund Horn, Robert Schloegl, 29 November 2014, Springer Science+Business Media New York].

As to the emission scenarios and change in the future due to the potential changing nature of drilling in the Monterey formation, this would be speculation and thus worst-case real world well drilling equipment and scenarios were used to complete the multi-well HRA. Again, well drilling operations (not chemicals associated with fracturing operations or any other potential fugitive hazardous VOCs) drove the risk result conclusions.

Various pieces of equipment and sources of emissions were not modeled in the multiple HRAs for various reasons or were included, as described below. Gas well are very rare and thus were not included. Artificial lift engines are typically electric so they would not result in emissions. Wellhead compressor engines, lateral compressor engines and hydraulic fracturing pumps all receive their power from the diesel drill rigs which are already accounted for in the HRAs. Well completion venting is put into production within 24 hours. Active venting is required to go through a flare and flare emissions were accounted for in the HRA. Blowdown venting (liquids uploading) and casing gas venting are prohibited and thus were not included. Dehydrators were included in the multi-well HRA. CARB regulations currently prohibit gas operated pneumatic devices. They are now required to be air operated. Product processing was included in the multi-well HRA. Well bore leakage and flowback are considered upset conditions and thus were not modeled in the HRAs. Hydraulic fracking proppants can contain toluene, methanol, benzene, naphthalene, but hydraulic fracturing, or well stimulation treatments (WST), 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. While silica can be used in fracturing sand and shipped to sites by truck, silica is not a known carcinogen in California and thus was not included in the HRAs. [CARB, February 2005 Reference exposure limits]. As demonstrated by the numerous HRA scenarios, VOCs do not contribute much to the overall health risk from drilling. Surface expressions from shallow cyclical steam products which emit VOCs and H2S are prohibited and are thus not included in the model. Gathering facilities, including separators, compressors, piping network, gathering tank, liquid knockout vessels, were part of the modeled sources. It is unclear how pig launchers or pipeline plugging would result in emissions.

An extensive list of production equipment was included in the single well HRA. Any electrified engines would not be included in an HRA as they do not result in emissions. Upset conditions and any fugitive leaks and/or other scenarios prohibited by law would also not be included in an HRA as they are speculative and not reasonably foreseeable. The HRA was intended to reflect worst-case potential scenarios. CEQA prohibits speculating on potential environmental impacts associated with unlikely or legally prohibited events.

The 2015 HRAs included an assumption of a thermally enhanced (TEOR) well as part of a worst-case emissions assumption. This is because hydraulic fracturing, or well stimulation treatments (WST) 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 would not cause air emissions. Instead, the chemicals are underground in the wells into which they were injected. Potential emissions associated with large diesel-fired frill rigs or workover rigs which could also be associated with well stimulation, have already been included and accounted for in all HRAs. To the extent that WST would cause air emissions separate from diesel exhaust, any potential off-gassing of WST fluids after well stimulation occurs are already included in the HRAs. Thus, the assumption that a hydraulic or acid fracked well or a combination of such rather than a thermally enhanced well was not necessary for the HRA analysis.

There was no need to consider deeper wells as only 5% of all wells in Kern County are deeper than 13,000 feet. An estimate that 198 wells per year could be drilled beyond 13,000 feet in Kern County is not accurate as it would be impossible to drill 198 wells to this depth in any one year given the limitations on drill rigs in Kern County discussed above. Even the multi-well HRA was based on very conservative assumptions that would be very hard to replicate in reality, due to both time required to drill and availability of drilling rigs.

HRA Modeling

Emission estimates included seven different construction phases (land preparation, drilling survey, well drilling, well completion, flowlines, pumping unit, and electrical) occurring simultaneously on a 13,000 foot well. This resulted in 1,143.76 pounds of diesel exhaust (primarily from well drilling and well completion) per well with the vast majority coming from well drilling (884.67 lbs/year) and well completion (245.25 lbs/year). *See* Appendix A of the Multi-Well HRA. This number was used for each of the Project HRAs. In addition to well construction, the multi-well scenario included potential well re-work every other year. This involved adding an additional 18.24 pounds per well of rework emissions.

The per well emission rate (without well-rework) is 16.3 pounds/well. However, the inclusion of well re-work (18.24 pounds) every other year results in approximately another 0.6 pounds (18.25/30 years = 0.60) or 16.9 pounds of diesel emissions per well. Therefore, that number was used to model wells identified as "E" wells. To be even more conservative, the wells identified as H, O and Q were assumed to have rework occur approximately 20 times during someone's lifetime (18.24/20 = 0.9 pounds per well). 16.3 + 0.9 = 17.2. Each of these scenarios included well emissions in excess of the 16.3 pounds used in the single well HRAs to account for well rework. Emissions were thus likely overstated for each well in order to be conservative.

Therefore, the actual emission rates used in the cumulative HRA are greater than only the well drilling rates as they include well rework. For 24 of the wells it was assumed that well rework would occur 20 times over the course of someone's lifetime (17.2 pounds per well), while for the other 24 wells it was assumed that rework would occur over 30 times during a person's lifetime (16.9 pounds per well). This results in a very slight net difference of 0.30 pounds of diesel particulate matter emissions over a 70-year exposure timeframe associated with the 24 hypothetical wells. Both scenarios significantly overstate actual expected emissions as all 48 wells are based on a very rare well depth of 13,000 feet.

The California Air Resources Board's Off-road emission factors show an approximate 48% reduction in diesel exhaust from off-road engines since the previous HRAs were completed in 2015, which, if the multi-well HRA were re-run in 2020, would result in emissions and corresponding risk of 4.84 in one million vs. the 9.3 in one million included in the multi-well HRA.

Exhaust temperature (761.9K) and stack exhaust velocity (71.23 m/s) were obtained from a local group of production engineers. These exhaust parameters for drill rigs were further confirmed in a 2014 study conducted by AECOM (AECOM 2014). This study showed primary drilling rig exhaust temperatures of 783K and an exit velocity of 71.1 m/s. (AECOM 2014, p.32].

The California AERMOD (air dispersion model used for health risk assessments) requires the use of local meteorological data. That data is obtained, processed and validated by each California air district for use in HRAs. That dataset known as AERMET was provided for this project by SJVAPCD, despite the fact that AERMINUTE may be recommended by EPA. AERMET was required to be used for HRA analysis in 2015 and continues to be required today for use in all permit applications, dispersion modeling and health risk assessments. Thus, re-running the HRA in 2020 would not change this modeling choice.

SJVAPCD required that the drill rigs be modeled as point sources. The area source is the mud sump.

HRA Conclusions

A third party perfectly recreated, correlated and replicated to four decimal places the findings of the multi-well HRA, finding modeled concentrations of 0.000964 ug/m^3 while the multi-well HRA's modeled concentrations of diesel exhaust were 0.000946 ug/m^3.

Again, diesel exhaust from off-road engines has reduced by approximately 48% in California since 2015. Therefore, previously calculated risk results would also be expected to reduce by almost half of the multi-well HRA were re-run in 2020. Therefore, if the previously completed very conservative theoretical example in the multi-well HRA were to be remodeled today, resulting risk would be approximately 4.84 in one million. This is significantly below the SJVAPCD health risk threshold of 20 in one million.

References

AECOM. 2014. North Slope Allowable Drill Rig Operation through Modeling and Monitoring Drill Rig Policy Working Group. August 1, 2014.

Baker Hughes. 2020. "North American Rotary Rig Count Pivot Table (Feb 2011–current)." North America Rig Count, Pivot Table. https://rigcount.bakerhughes.com/static-files/6c34be5d-447f-49db-a9a7-78e30b2408c3.

APPENDIX A – Well Construction Input Assumptions

2017 Emissions from a 13,000' Well

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Water Truck	1	7	8.48	400	2.72
Loader	1	4	2.5	100	.29
35 Yard Dump Truck	1	2	1.00	400	.09
Grader	1	4	2.5	175	.68
Skip & Scrap (Backhoe)	1	1	1.0	100	.03
Big Scrapper	1	2	2.5	362	.41
Dozer (D9R)	1	1	1.0	255	.08
Low Bed Truck/Trailer	1	2	.5	400	.05
Dump Truck 10 Wheels	1	1	.5	400	.02
Backhoe	1	2	.54	100	.03
Loader	1	3	2.5	100	.22
Loader	1	2	1.0	100	.06
Escavator (Backoe/tracks)	1	1	1.0	163	.02
Dozer (D8T)	1	1	1.0	255	.08
End Dump Truck & Trailer	1	1	.50	400	.02
Grader	1.0	1.0	.50	175	.03

Construction Activity: A.1 Land Preparation

2017 Emissions from a 13,000' Well
Construction Activity: B.1 Drilling Survey

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Rig	1	1	12	100	0.58
Cement Truck	1	1	12	400	0.55

2017 Emissions from a 13,000' Well
Construction Activity: C.1 Well Drilling

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equipment (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Portable Crane	1	2	8	230	0.69
Port Light Stands	5	44	12	20	19.06
Portable Gen. Hydraulic Power	1	44	22	80	27.45
Portable Gen. DSM/Trailers	2	44	24	100	74.85
Portable Gen. Mud Separator	1	43	22	420	45.51
Diesel Electric – Rotary	1	43	22	158	57.08
Diesel Electric Hoist	1	43	22	1094	182.62
Diesel Electric Hoist	1	43	22	962	160.58
Diesel Electric Hoist	1	43	22	1898	316.83

2017 Emissions from a 13,000' Well
Construction Activity: D.1 Well Completion

Vehicle Category and Use	Equipment		Engine		
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Accumulator Generator	1	17	24	100	12.76
Filter Skid (Pump)	1	2	3	90	0.19
Acid Pump #1 (Hydraulic Oil Pump)	1	1	22	175	0.72
Acid Pump #2 (Acid Fluid Pumping)	1	1	22	765	1.45
Generator for Doghouse for WO Rig	1	17	24	70	8.93
3 Light Plants for WO Rig	3	17	12	20	3.90
Diesel Engine for COROD or Other	1	1	22	450	1.49
Portable Den. Mud Separator	1	17	22	420	15.87
Diesel Electric – Rotary	1	17	22	144	18.15
Diesel Electric Hoist and Pump	1	17	22	996	58.00
Diesel Electric Hoist and Pump	1	17	22	981	57.12
Diesel Electric Hoist and Pump	1	17	22	1145	66.67

2017 Emissions from a 13,000' Well
Construction Activity: E.1 Well Flowline

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equip (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Side Boom D4/Crawler	1	3	10	520	0.79
Backhoe	1	3	10	95	0.84
Pipe Fitting or Welders	1	3	10	40	0.43
Hydrotest Pump	1	1	1	20	0.01
Forklift	1	3	10	125	0.49
Other Equipment/Bending Machine	1	3	10	80	1.04

2017 Emissions from a 13,000' Well
Construction Activity: F.1 Pump Unit

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equip (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Power Generator	1	2	8	10	0.06
Backhoe	1	2	4	80	0.19
Welder	1	2	8	25	0.14

2017 Emissions from a 13,000' Well
Construction Activity: G.1 Electrical

Vehicle Category and Use	Equipment		Engine		Emissions from Offroad Mobile Source Equip (Lb/Well)
Description of Offroad Equipment	Count	Op Days	Hr/Day	HP	PM10
Line Truck	1	4	10	250	1.50
Bucket Truck	1	4	10	250	1.50
Electrical Service Truck	1	4	1	300	0.14
Power Generators	1	4	1	10	0.01
Back-Hoe	1	1	10	650	0.74

APPENDIX B

SUMMARY OF AIR DISPERSION MODELING PROGRAM CHANGES SINCE 2015

In 2015, Environmental Compliance Solutions, Inc. (ECS) assisted with the Environmental Impact Report for *Revisions to the Kern County Zoning Ordinance – 2015C, focused on Oil and Gas Local Permitting*. We completed the Health Risk Assessment (HRA) technical appendix which included numerous HRAs prepared to calculate potential air quality health risks from various hypothetical well drilling scenarios throughout the county.

California's HRA procedures require the use of both the United States Environmental Protection Agency's (EPA's) AERMOD model and the California Air Resources Board's (CARB's) Hotspots Analysis and Reporting Program (HARP2) model (CARB 2015). California's Office of Health Hazard Assessment (OEHHA) provides toxicity levels for all hazardous air pollutants to be modeled.

CARB made significant modifications to the HARP2 model in March 2015 and that version of the model was used for all calculations completed for the abovementioned CEQA document.

Between 2015 and now, minor updates to AERMOD and HARP2 have been released. Specific changes to each model are outlined in Attachment A. OEHHA has not modified or revised the toxicity factors for any of the chemicals (diesel particulate matter, benzene, cyclohexane, ethylbenzene, n-hexane, toluene, xylenes, 1,2,4 trimethylbenzene, and hydrogen sulfide) used in the 2015 well drilling study.

Conclusion

As is detailed in Attachment A, none of the changes or updates from the three regulatory agencies are believed to potentially alter the conclusions of the 2015 Kern County study.

Attachment A
Summary of Specific Modeling Updates Since 2015

EPA's AERMOD Updates

Subsequent to the Kern County analysis, EPA released three updated versions (16286, 18086, and 19191) of AERMOD. Specific revisions are summarized below.

v.16286: EPA updated a source release height input. This could potentially change previous results in a small, negligible way.

v.18086: This model version changed the wind downwash algorithm, but downwash was not needed as part of the previous study; therefore, no change to results is expected.

v.19191: Key updates included incorporating background concentrations into model results, particle deposition, low wind speed options and buoyant line sources. This would not be expected to change previous results.

CARB's HARP2 Updates

CARB has updated HARP2 nine times since 2015. Specific version changes are outlined below. No change was identified that might alter the conclusions of the 2015 HRAs in any substantive way.

v.16057: This version involved corrections to repair problems that were causing the model to fail; and thus would not affect previously-run analyses. Additionally, multipathway options and reporting presentation methods were updated that would not be expected to change previous results.

v.16088: This version fixed issues with a non-default model that was not used in the 2015 studies. New health table (risk factors) processors were also incorporated in this version for toxic compounds that were not part of the Kern County 2015 HRAs.

v.16217: Changes in this release affected operational aspects of the model and were not related to risk calculations.

v.17023: This version updated the computer program's functionality and efficiency of use (i.e., HRACalc processor and data importer upgrades). These were not areas that affected the Kern study.

v.17052: This release improved model functionality and updated information for some substances not part of the study.

v.17320: This update included additional model functionality, added specific air district health data tables and updated the AERMOD model. These changes would not affect the Kern study.

v.18159: This update included an updated AERMOD module, corrected importing and exporting information, and updated the health table. The updated health table did not make changes to any of the hazardous air pollutants analyzed in the previous study.

v.19044: This update improved functionality, updated the health table and updated the HRACalc processor. These changes would not be expected to affect the results of the Kern study.

v.19121: This update changed the building downwash algorithm. Building downwash was not used in the Kern study and thus would not alter the results.

Appendix C

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

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Kern County
Agt.# 890-2016

OIL AND GAS EMISSION REDUCTION AGREEMENT 20160168

This Oil and Gas Emission Reduction Agreement ("Agreement") is entered into as of August 18th [date], 2016, by and between the COUNTY OF KERN ("County") and the SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, an air pollution control district formed pursuant to California Health and Safety Code section 40150, et seq. ("District").

RECITALS

WHEREAS, the County approved amendments to the Kern County Zoning Ordinance regulating oil and gas production, including Chapter 19.98 and related sections of the Zoning Ordinance ("Project" or "Ordinance"), and certified an Environmental Impact Report ("EIR") for the Project, on November 9, 2015; and

WHEREAS, the Project requires compliance with the Ordinance and the EIR mitigation measures, including but not limited to Air Quality Mitigation Measures 4.3-1 to 4.3-8, attached hereto as Exhibit A, and incorporated herein ("Emission Reduction Mitigation Measures"), in order to significantly reduce Project air quality impacts associated with the Project; and

WHEREAS, despite incorporation of various emission reduction mitigation measures, without additional emission reductions the Project would cause impacts on air quality within the geographical boundaries of the San Joaquin Valley Unified Air Pollution Control District, as depicted on Exhibit B attached hereto and incorporated herein (the "District Boundaries"); and

WHEREAS, County has required in Mitigation Measure 4.3-8 that applicants for County oil and gas permits issued under the Ordinance ("Applicants") fully mitigate emissions of Nitrogen Oxide (NOx), Reactive Organic Compounds (ROGs) and Particulate Matter 10 microns or less in size (PM_{10}) of County-permitted applicant activities ("Applicant Activities") under the Ordinance through emission reductions that are either: (1) implemented by the Applicant, with

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the quantity of emission reductions verified by the District; or (2) funded by the Applicant through the District's incentive programs, as described below; and

WHEREAS, the District is an air pollution control district formed by the counties of Fresno, Kern, Kings, Madera, Merced, San Joaquin, Stanislaus and Tulare, pursuant to California Health and Safety Code section 40150, et seq.; and

WHEREAS, District is responsible for developing and implementing air quality control measures within the District Boundaries, including air quality control measures for stationary sources, transportation sources, and indirect sources; and

WHEREAS, the District has developed emission reduction incentive programs that have been designed around several core principles, including cost-effectiveness, integrity, effective program administration, excellent customer service, the efficient use of District resources, fiscal transparency and public accountability; and

WHEREAS, the District's incentive programs and regulatory activities are regularly audited by independent outside agencies including professional accountancy corporations on behalf of the federal government, the California Air Resources Board (ARB), the California Department of Finance and the California Bureau of State Audits; and

WHEREAS, the District has determined that with appropriate funding, where necessary, the District can provide: (1) protocols for measuring and verifying emission reductions achieved by Applicants to offset emission increases; and (2) reductions of emissions through District incentive programs to achieve emission reductions in sufficient quantities to comply with Mitigation Measure 4-3-8; and

WHEREAS, consistent with their lead and responsible agency roles under CEQA, the County and the District will consult, and the District will provide the County with its expert advice, as to the emission reductions in greenhouse gas emissions (GHG) that can be achieved from GHG emission reduction proposals by Applicants and/or by other third parties as part of the implementation and monitoring of Greenhouse Gas Mitigation Measure (GHG-2a), but that this Agreement does not encompass GHG Mitigation Measures; and

WHEREAS, County and District desire to enter into this Agreement in order to assure implementation of Mitigation Measure 4.3-8, with per well emission reductions in the amounts set forth in Exhibit C ("Per Well Emission Schedule"). As a result of the implementation of this Agreement, the development of the Project will result in no net increase in these designated criteria emissions from the oil and gas production activities regulated by the Ordinance.

AGREEMENT

NOW THEREFORE, in exchange of the mutual covenants herein contained, County and District hereby agree as follows:

1. Mitigation of Project-Related Impacts on Air Quality

Project-related Criteria Pollutant Emissions not required to be offset per District rules shall be fully mitigated by achieving surplus, quantifiable and enforceable emission reductions for ROG, NOx, and PM_{10} (collectively, "Mitigation of Criteria Pollutants"). "Surplus" emission reductions are reductions that are not otherwise required by laws or regulations. The determination of whether proposed emission reductions are surplus shall be performed by the District.

1.1 Required Emission Mitigation

County shall require Applicants to mitigate Criteria Pollutants for each well for which Site Conformity Review is required under Section 19.98.070 of the Kern County Zoning Ordinance ("County Permit Process"), in the amounts set forth in Exhibit C, and as adjusted annually per Paragraph 1.2(b).

1.2 Required Emission Mitigation Fee

(a) County shall require Applicants to pay to the County, as part of the County Permit Process, an Emission Mitigation Fee ("Mitigation Fee").

(b) The Mitigation Fee amount due to the County from each Applicant shall be calculated by multiplying the applicable Per Well Emission

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Factor by the per ton emission reduction cost average ("Cost Effectiveness") as reported by the District in the most recently published annual San Joaquin Valley Air Pollution Control District Indirect Source Review Program Report ("ISR Report"). The Cost Effectiveness as set forth in the District's 2015 ISR Report is $7,231 per ton.

(c) The County shall deposit all Mitigation Fee payments received in a dedicated account which includes the identity of each Applicant paying a Mitigation Fee, and shall transfer such funds to the District quarterly to fund emission reduction projects or programs pursuant to this Agreement.

(d) If an Applicant pays a Mitigation Fee in accordance with Section 1.2(a), above, but does not commence construction or drilling activities before expiration of the County permit authorizing such work, then the Mitigation Fee will be refunded by the County to such Applicant within 180 days of the County's receipt of written notice from the Applicant of the expiration of such well permit; provided, however, that the County shall not refund any Mitigation Fee for a well for which any construction or drilling activities have been commenced.

1.3 Use of Mitigation Fees to Reduce Emissions

(a) The County and District agree that cost-effectiveness should be a key consideration in selecting among emission reduction projects to be funded through mitigation fees ("Mitigation Fee Projects"), and emission reduction projects in Kern County should be prioritized ahead of Mitigation Fee Projects elsewhere in the District. The Parties agree to balance these policy goals as follows:

(b) The County will engage in outreach efforts to identify Mitigation Fee Projects in Kern County, and will list such projects for review by the District. The District and County shall regularly meet and confer regarding potential projects, and regarding the final selection of Mitigation Fee Projects.

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(c) In selecting emission reduction projects, the District shall use the following criteria:

(i) If Kern County Mitigation Fee Projects are the most cost-effective and achieve the required emission reductions, then all Mitigation Fee Projects shall be in Kern County.

(ii) If Kern County Mitigation Fee Projects are not the most cost-effective, then Kern County projects costing up to $250 per ton more than the most cost effective Mitigation Fee Projects outside Kern County shall nevertheless be selected by the District to spend up to twenty percent of the Mitigation Fee funds available for required emission reductions from Mitigation Fee Projects. If Kern County Mitigation Fee Projects cost more than $250 per ton more than the most cost effective Mitigation Fee Projects in other counties within the District, then Mitigation Fee Projects from outside the County may be selected by the District to achieve the required emission reductions.

1.4. Applicant-Sponsored Emission Reduction Projects

(a) The EIR allows applicants required to obtain permits under the Ordinance to propose and implement their own emission reduction projects in lieu of paying some or all of an air quality Mitigation Fee ("Applicant Emission Reduction Project"). Applicant(s), or an association representing two or more Applicants, shall meet and confer with the County to explain a proposed project and to provide the County an opportunity to help prioritize emission reductions from such projects within Kern County.

(b) Applicant(s) or an association representing two or more applicants (collectively, "Applicant") may propose an Applicant Emission Reduction Project to the District, after County review, for the District's review and validation of emission reduction quantities. Applicant shall enter into a separate agreement with the District to pay the District's staff costs (or, if acceptable to District, an approved outside consultant), to develop, review and approve emission

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reduction quantities for Applicant Emission Reduction Projects. The District shall consult with the County on the practical ability to implement Applicant Emission Reduction Project as part of the District's review process, including but not limited to appropriate accounting of emission reductions for projects that mitigate emissions for multiple wells.

(c) The County shall credit Applicant Emission Reduction Projects in emission reduction amounts approved by the District, and shall not collect air emission Mitigation Fees to the extent that Applicant possess District-approved emission reductions that offset emission increases from new well permits based on the applicable Per Well Emission Schedule.

(d) For emission reductions approved by the District for a completed Applicant Emission Reduction project that reduces emissions by retrofitting or making other changes to existing wells, or other existing equipment or activities, the quantity of emission reductions approved by the District may be transferred by the Applicant possessing such reductions ("Transferor") to a different Applicant holding or seeking a permit under the County Permit Process ("Transferee"). To effect a valid emission reduction transfer under this section of the Agreement, the Transferor must first notify the County and District in writing of the proposed transfer ("Transfer Notice"). Following receipt of a Transfer Notice, the County, in consultation with the District, will assign the transferred emission reduction amount to the Transferee and deduct this amount from the Transferor.

(e) The County shall be responsible for confirming that the District-approved Applicant Emission Reduction Project has been implemented, unless District agrees to do so pursuant to Applicant-District agreement.

1.5 Per Well Emission Factor Adjustments

(a) Other than the annual adjustment specified in paragraph 1.2(b), no modification of the per ton Mitigation Fee amount is authorized.

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Additionally, no modification of the Per Well Emission Schedule is authorized except as set forth below:

(i) the County approves a revised air quality impact assessment, which is reviewed as required under CEQA and is approved by the District, that demonstrates that Project-related air quality impacts are less than originally quantified, and accordingly, that Exhibit C should be revised; or

(ii) the District's rules or regulations change such that Project-related emissions that are not, as of the effective date of this Agreement, required to obtain offsets under District stationary source permitting rules, are subsequently by modified District rules or regulations required to obtain such offsets, at which point Applicant Activities for which, and to the extent which, offsets are required by such future District rules and regulations shall be subtracted from the Per Well Emission Schedule as approved by the District and County; or

(iii) an alternate per well emission schedule ("Alternate Schedule") associated with development of cleaner technology is approved for emission reductions from Applicant Activities. An Applicant, association of Applicants, or other group of Applicants seeking approval of an Alternate Schedule ("Alternate Schedule Applicant") shall first seek approval from the County, and upon County concurrence, may enter into an agreement with the District, to develop an Alternate Schedule of emission estimates for well construction activities that reflect additional variables not considered in the Per Well Emission Schedule and result in lower emissions. As of the effective date of this Agreement, the County has concurred that early deployment of lower or zero emission construction equipment and related engines are eligible for consideration by the District for development of an Alternate Schedule for Alternate Schedule Applicants that volunteer to use lower emission construction equipment in advance of applicable regulatory deadlines. An Alternate Schedule Applicant shall pay the District's staff costs (or, if acceptable to District, an approved outside consultant),

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to develop, review and approve any Alternate Schedule approved by the County for District. The District shall consult with the County to assure the practicality of implementation by the County of any Alternate Schedule as part of the District's schedule review process. Upon County and District approval of such an Alternate Schedule, that schedule may be selected by an Alternate Schedule Applicant in the County Permit Process to calculate the emission reduction quantity component of the Air Mitigation Fee calculation. An Alternate Schedule approved for use by an Alternate Schedule Applicant may be used by another Applicant only upon submittal to the County and District of the written consent of the Alternate Schedule Applicant, and only if the District and County concur that the Applicant has met all applicable technology and other required eligibility criteria for use of the Alternate Schedule.

(b) Any adjustments to Per Well Emission Schedule made pursuant to subsections (i) or (iii) above shall be reported annually as set forth in Section 2 below.

1.6. Matching Funds

Nothing in this Agreement precludes, and the Parties encourage, the use of Mitigation Fees paid under this program as matching fees to fund emission reduction projects which are partly funded by a federal or state agency. Determination of the amount of emission reduction credits for these partially-funded emission reduction projects shall be made by the District in consultation with the federal or state grantor agency.

1.7. District Administration Costs

As of the effective date of this Agreement, the County shall add and collect from applicants a four percent (4%) administrative charge to the Mitigation Fee to pay for the District's administrative costs in implementing this Agreement. The County is not charging for its additional administrative oversight costs under this Agreement. The District's 4% administrative charge does not apply to Applicant

Emission Reduction Projects, or for review of Applicant-initiated Alternate Schedule proposals, which Applicants must fund by separate agreement with the District.

2. Annual Reporting of Emission Reductions

The District will annually report on total tons of emission reductions achieved pursuant to this Agreement, inclusive of Applicant Emission Reduction Projects and emission reductions from Mitigation Fee Projects. Any adjustments to Per Well Emission Schedule completed under Section 1.5 above shall also be reported annually by the District. The annual emission report data will be used by the County and disclosed to the public as part of the County's Mitigation Monitoring and Reporting Program.

3. Excess Emission Reductions

County shall be credited with all emission reductions achieved by District through this Agreement that exceed the amount of required emission reductions for the Project ("Excess Emission Reduction"). Nothing in this Agreement shall prohibit future agreements by the District and County regarding other distributions of Excess Emission Reductions.

4. Compliance with District Rules and Regulations

County acknowledges that notwithstanding this Agreement, Applicants remain subject to and are required to comply with all applicable District rules and regulations.

5. CEQA Compliance

The County shall remain fully responsible as the lead agency for enforcing the Ordinance and monitoring to assure implementation of the Mitigation Measures included in the EIR, and for preparing annual reports pursuant to the County's Mitigation Monitoring and Reporting Program.

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6. Additional District Obligations

District shall ensure that the owners/operators of equipment subject to funding agreements for District Incentive Program Emission Reductions perform all obligations to be performed on the part of such parties under said funding agreements.

7. Subsequent Litigation, Legislation and/or Administrative Action/Credit to County

In the event that despite this Agreement, the County is required as a result of a final judgment or District Approved Settlement (as defined below) in any third party litigation, to pay air quality mitigation funds in addition to the Air Quality Mitigation Fees paid under Paragraph 1 above, then District shall acknowledge and credit the County with emission reductions achieved pursuant to Paragraph 1, and any additional emission reductions achieved to mitigate the Project-related impacts on air quality that will result from payment of such additional monies. For purposes of this Paragraph, a "District Approved Settlement" shall mean a settlement of a lawsuit filed pursuant to CEQA, the National Environmental Policy Act or other applicable environmental law which: (i) provides for the County's (or an Applicant(s)') payment of monies or commitment to spend a specified dollar amount on emission mitigation in exchange for a dismissal of such lawsuit, (ii) provides for the use of such monies in such a manner as to further reduce Project-related air emissions, and (iii) is approved in writing by District. The District shall have no authority to settle, or otherwise, commit the Air Quality Mitigation Fees in any settlement of, a third party lawsuit without the County's consent.

8. Term of Agreement and Periodic Review/Revision Process

This Agreement shall be effective upon the date first written above, and shall remain in effect indefinitely, unless or until terminated or amended by a party.

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Because this is a new County permit program rather than a single-facility/single-developer VERA permit model, it is anticipated that periodic review and potential revisions to the implementation procedures of the Agreement will be needed over time.

As part of the periodic review, the parties shall consider whether the average per ton emission reduction cost achieved by Mitigation Fee Projects is substantially superior to the average per ton emission reduction cost identified in the ISR Report, taking into account both Indirect Source and Voluntary Emission Reduction Agreement emission reduction cost data. If so, the parties shall consider utilizing the average per ton emission reduction cost achieved by Mitigation Fee Projects for purposes of item 3.3.

County may, at any time by written notice to District, terminate this Agreement, whereupon, (i) District shall acknowledge in writing to the County that County has mitigated air quality impacts of the Project to the extent and in the types and quantities brought about by Funding Agreements and Mitigation Measures, (ii) District shall refund to County any unused portion of County's Mitigation Fee funds less any unpaid administrative costs incurred; and (iii) neither County nor District shall have any further rights or obligations under this Agreement except as expressly provided. District's obligations to oversee implementation of funding agreements pursuant to Paragraph 6 (Additional District Obligations), shall remain effective for as long as necessary to ensure that the anticipated emission reductions associated with each funding agreement continue to be achieved for the life of the agreement, to the extent such agreement was funded by County's Mitigation Fee funds.

9. Representations, Covenants and Warranties

9.1. County's Representations, Covenants and Warranties.

County represents, covenants and warrants to District, as of the date of this Agreement, as follows:

(a) The undersigned representatives of County are duly authorized to execute, deliver and perform this Agreement, and upon County's execution and delivery of this Agreement, this Agreement will have been duly authorized by County.

(b) Upon execution and delivery of this Agreement by County, County's obligations under this Agreement shall be legal, valid and binding obligations of County, duly enforceable at law and in equity in accordance with the terms and conditions of this Agreement.

(c) There is no lawsuit, legal action, arbitration, legal or administrative proceeding, legislative quasi-legislative or administrative action or claim existing, pending, threatened or anticipated which would render all or any portion of this Agreement invalid, void or unenforceable in accordance with the terms and conditions thereof.

(d) Other than the execution and delivery of this Agreement by the undersigned representatives of County, there are no approvals, consents, confirmations, proceedings, or other actions required by County or any third party, entity or agency in order to enter into and carry out the terms, conditions and intent of the parties with respect to this Agreement, except as required to enter Funding Agreements.

9.2. District's Representations, Covenants and Warranties

District represents, covenants and warrants to County, as of the date of this Agreement, as follows:

(a) The undersigned representatives of District are duly authorized to execute, deliver and perform this Agreement, and upon District's execution and delivery of this Agreement, this Agreement will have been duly authorized by District.

(b) Upon execution and delivery of this Agreement by District, District's obligations under this Agreement shall be legal, valid and binding obligations of District, duly enforceable at law and in equity in accordance with the terms and conditions of this Agreement.

(c) There is no lawsuit, legal action, arbitration, legal or administrative proceeding, legislative, quasi-legislative or administrative action or claim existing, pending, threatened or anticipated which would render all or any portion of this Agreement invalid, void or unenforceable in accordance with the terms and conditions thereof.

(d) Other than the execution and delivery of this Agreement by the undersigned representatives of District, there are no approvals, consents, confirmations, proceedings, or other actions required by District or any third party, entity or agency in order to enter into and carry out the terms, conditions and intent of the parties with respect to this Agreement, except as required to enter Funding Agreements.

(e) Upon the approval of this Agreement by the governing board of District, the Air Pollution Control Officer of District, or equivalent representative, or a delegee of such officer, shall have the authority to approve, deliver, verify, enter into, acknowledge and/or accept any communication, notice, notification, verification, agreement and/or other document to be issued or entered into by District under the terms and conditions of this Agreement, without further approval of the governing board of District.

10. Recitals Incorporated

The recitals set forth hereinabove are hereby incorporated into this Agreement and acknowledged, agreed to and adopted by the parties to this Agreement.

11. Further Assurances

County and District agree to execute and deliver any documents and/or perform any acts which are reasonably necessary in order to carry out the intent of the parties with respect to this Agreement.

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12. No Joint Venture or Partnership

District and County agree that nothing contained in this Agreement or in any document executed in connection with this Agreement shall be construed as making District and County joint venturers or partners.

13. Notices

Any notices or communications relating to this Agreement shall be given in writing and shall be deemed sufficiently given and served for all purposes when delivered, if (a) in person, (b) by facsimile (with the original delivered by other means set forth in this paragraph, or (c) by generally recognized overnight courier or (d) by United States Mail, certified or registered mail, return receipt requested, postage prepaid, to the respective addresses set forth below, or to such other addresses as the parties may designate from time to time by providing written notice of the change to the other party.

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& Natural Resources Department
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14. Entire Agreement

The terms of this Agreement, together with all attached exhibits, are intended by the parties as the complete and final expression of their agreement with respect to such terms and exhibits and may not be contradicted by evidence of any prior or contemporaneous agreement. This Agreement specifically supersedes any prior written or oral agreements between the parties with respect to the subject matter of this Agreement.

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15. Amendments and Waivers

No addition to or modification of this Agreement shall be effective unless set forth in writing and signed by the party against whom the addition or modification is sought to be enforced. The party benefited by any condition or obligation may waive the same, but such waiver shall not be enforceable by another party unless made in writing and signed by the waiving party.

16. Invalidity of Provisions

If any provision of this Agreement as applied to either party or to any circumstance shall be adjudged by a court of competent jurisdiction to be void or unenforceable for any reason, the same shall in no way affect (to the maximum extent permissible by law) any other provision of this Agreement, the application of any such provision under circumstances different from those adjudicated by the court, or the validity or enforceability of this Agreement as a whole. The parties further agree to replace any such invalid, illegal or unenforceable portion with a valid and enforceable provision, which will achieve, to the maximum extent legally possible, the economic, business or other purposes of the invalid, illegal or unenforceable portion.

17. Construction

Unless otherwise indicated, all paragraph references are to the paragraph of this Agreement and all references to days are to calendar days. Whenever, under the terms of this Agreement the time for performance of a covenant or condition falls upon a Saturday, Sunday or California state holiday, the time for performance shall be extended to the next business day. The headings used in this Agreement are provided for convenience only and this Agreement shall be interpreted without reference to any headings. Wherever required by the context, the singular shall include the plural and vice versa, and the masculine gender shall include the feminine or neuter genders, or vice versa. This Agreement may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. The language in all parts of this Agreement shall be construed as a whole in accordance with its fair meaning, and shall not be construed against any party solely by virtue of the fact that such party or its counsel was primarily responsible for its preparation.

18. Governing Law

18.1 California Law Governs

The rights and obligations of the parties and the interpretation and performance of this Agreement shall be governed in all respects by the laws of the State of California.

18.2 Venue

Venue for any action arising out of or relating to this Agreement shall be in Kern County, California.

19. Exhibits

The exhibits attached to this Agreement shall be deemed to be a part of this Agreement and are fully incorporated herein by reference.

20. Force Majeure

The time within which any party shall be required to perform under this Agreement shall be extended on a day-per-day basis for each day during which such performance is prevented or delayed by reason of events reasonably outside of the control of the performing party, including, without limitation, acts of God, events of destruction, acts of war, civil insurrection, strikes, shortages, governmental delays, moratoria, civil litigation and the like, and/or delays caused by the non-performing party's act or omission.

IN WITNESS WHEREOF, County and District have executed this Agreement and agree that it shall be effective as of the date first written above.

////

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Fresno, CA 93726
(559) 230-6000

COUNTY

Board of Supervisors
County of Kern

JUL 26 2016

By: ______________________
Chairman, Board of Supervisors
MICK GLEASON

Recommended for approval

Kern County Planning and Natural Resources Department

By: ______________________
Lorelei H. Oviatt, AICP Director

APPROVED AS TO FORM
Office of County Counsel
By ______________________
County Counsel

DISTRICT

San Joaquin Valley Unified Air Pollution Control District

____
Governing Board Chair

Recommended for approval:

San Joaquin Valley Unified Air Pollution Control District

____
Seyed Sadredin
Executive Director/APCO

Approved as to legal form:

San Joaquin Valley Unified Air Pollution Control District

____
Annette Ballatore-Williamson
District Counsel

Approved as to accounting form:

____
Mehri Barati
Director of Administrative Services

For accounting use only:

San Joaquin Valley Unified Air Pollution Control District

Program: ______________
Account No: ______________

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EXHIBIT A

AIR QUALITY MITIGATION MEASURES 4.3-1 TO 4.3-8

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 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 on-site 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. 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. 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%.

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	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. 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.
MM 4.3-5	Construction: The Site Plan Application shall include a Site Vicinity Figure showing the location of any sensitive receptor(s) within 3,000 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. b. If there are sensitive receptors within the potential impact area, then additional information must be provided showing the setback from the closest edge of the well pad to the property line of the nearest sensitive receptor. The minimum distances shall be as follows:

Well Depth (Feet)	Minimum Setback Distance from Well Site to Adjacent Property Line of an Existing Sensitive Receptor (Feet)
Western Subarea	
10,000	367
5,000	116

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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 setbacks cannot be met, and for existing wells, the Applicant shall provide a site-specific or other risk assessment to the San Joaquin Valley Air Pollution Control District, which may 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, and shall provide confirmation 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:

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.
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. Assist and pay to relocate residents to temporary lodging during well construction, drilling, and completion activities, if such residents voluntarily agree to such relocation.

MM 4.3-6	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. 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 appropriate mask practices as part of the Worker Environmental Awareness Training Program.
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.

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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 oxides of nitrogen, reactive organic gases, and particulate matter of 10 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.

EXHIBIT B
DISTRICT BOUNDARIES

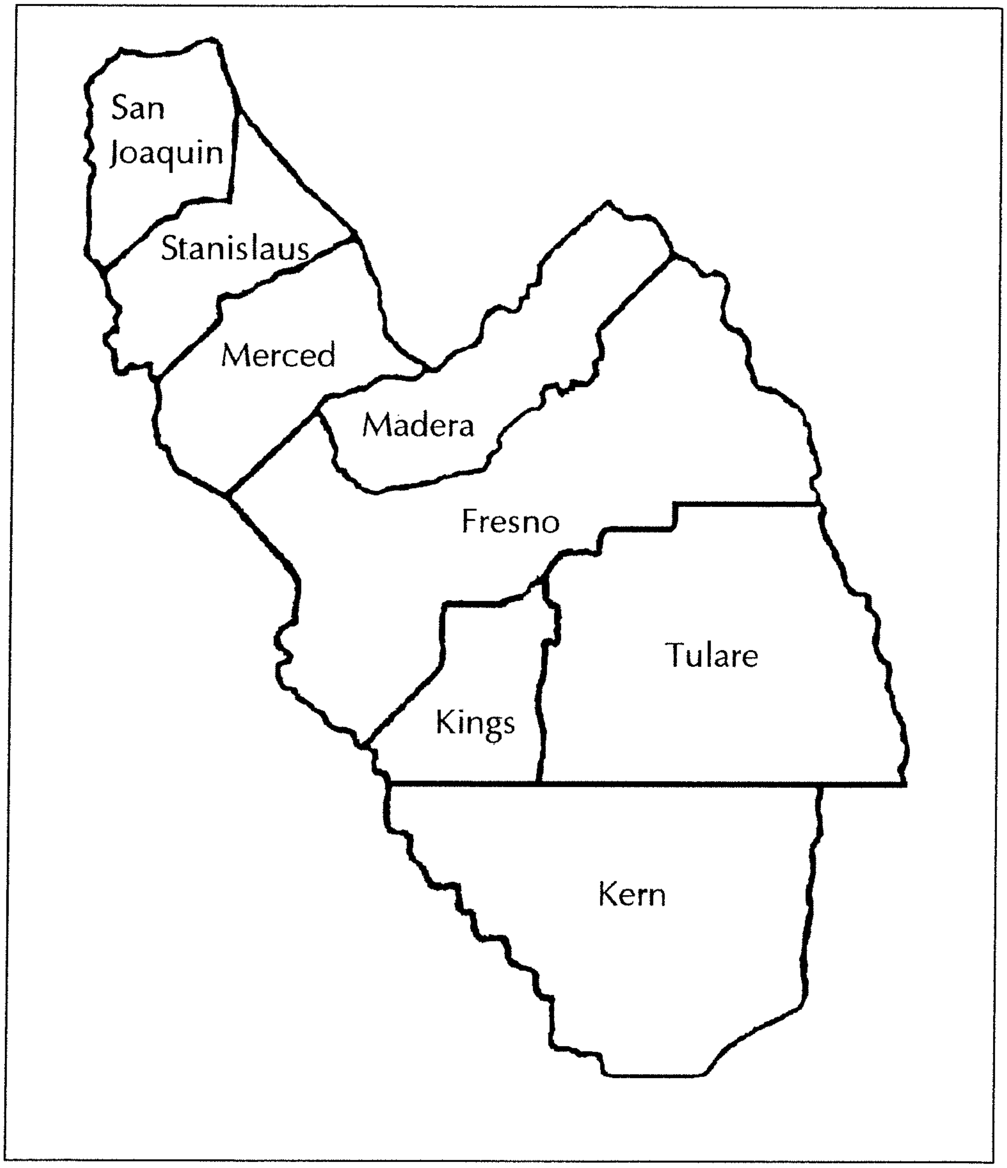

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EXHIBIT C

PER WELL EMISSION SCHEDULE

Lorelei H. Oviatt, AICP, Director
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Bakersfield, CA 93301-2323
Phone: (661) 862-8600
Fax: (661) 862-8601 TTY Relay 1-800-735-2929
Email: planning@co.kern.ca.us
Web Address: http://pcd.kerndsa.com/

PLANNING AND NATURAL RESOURCES DEPARTMENT

Planning
Community Development
Administrative Operations

July 12, 2016

Proposed Per Well Emissions and Related Fees (Exhibit C)

The following table details the total emissions of all oil and gas activities on a per well basis. The table is segmented into 1000' well depth increments and the fee is calculated using $7,231* per ton.

Total NOx, ROG, and PM Emissions Per Well By Subarea and Well Depth

Measured Well Depth (Feet)	Emissions in Tons Per Well					
	Western Zone	Fee	Central Zone	Fee	Eastern Zone	Fee
Up to 1000	1.28	$ 9,255.68	1.63	$ 11,786.53	0.96	$ 6,941.76
Up to 2000	1.52	$ 10,991.12	1.94	$ 14,028.14	1.15	$ 8,315.65
Up to 3000	1.78	$ 12,871.18	2.27	$ 16,414.37	1.37	$ 9,906.47
Up to 4000	2.03	$ 14,678.93	2.59	$ 18,728.29	1.57	$ 11,352.67
Up to 5000	2.35	$ 16,992.85	3.04	$ 21,982.24	1.8	$ 13,015.80
Up to 6000	3.98	$ 28,779.38	4.81	$ 34,781.11	3.33	$ 24,079.23
Up to 7000	4.55	$ 32,901.05	5.51	$ 39,842.81	3.81	$ 27,550.11
Up to 8000	5.36	$ 38,758.16	6.52	$ 47,146.12	4.49	$ 32,467.19
Up to 9000	6.17	$ 44,615.27	7.53	$ 54,449.43	5.16	$ 37,311.96
Up to 10000	7.47	$ 54,015.57	9.16	$ 66,235.96	6.23	$ 45,049.13
Up to 11000	14.18	$ 102,535.58	16.21	$ 117,214.51	12.71	$ 91,906.01
Up to 12000	16.56	$ 119,745.36	19.06	$ 137,822.86	14.77	$ 106,801.87
Up to 13000	18.85	$ 136,304.35	21.87	$ 158,141.97	16.69	$ 120,685.39
Up to 14000	22.08	$ 159,660.48	25.77	$ 186,342.87	19.47	$ 140,787.57
Up to 15000	25.88	$ 187,138.28	30.37	$ 219,605.47	22.72	$ 164,288.32
Up to 16000	33.67	$ 243,467.77	39.23	$ 283,672.13	29.79	$ 215,411.49
Up to 17000	39.96	$ 288,950.76	46.78	$ 338,266.18	35.21	$ 254,603.51
Up to 18000	47.84	$ 345,931.04	56.26	$ 406,816.06	41.99	$ 303,629.69
Up to 19000	57.51	$ 415,854.81	67.86	$ 490,695.66	50.35	$ 364,080.85
Up to 20000	69.76	$ 504,434.56	82.57	$ 597,063.67	60.91	$ 440,440.21
Up to 21000	88.91	$ 642,908.21	104.65	$ 756,724.15	78.08	$ 564,596.48
Up to 22000	108.45	$ 784,201.95	127.92	$ 924,989.52	95.05	$ 687,306.55
Up to 23000	132.43	$ 957,601.33	156.49	$1,131,579.19	115.89	$ 838,000.59
Up to 24000	161.51	$1,167,878.81	191.23	$1,382,784.13	141.1	$1,020,294.10
> 24000	197.8	$1,430,291.80	234.51	$1,695,741.81	172.61	$1,248,142.91

*Note: The dollar amounts on this Table will be adjusted annually based on the ISR report as described in Section 1.2(b) of the Agreement.

Appendix D

Supplemental Water Supply Baseline Technical Report (2020)

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Supplemental Water Supply Baseline Technical Report

Prepared by:
Kern County Planning and
Natural Resources Department
2700 "M" Street, Suite 100
Bakersfield, CA 93301

July 2020

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Supplemental Water Supply Baseline Technical Report (2020)

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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1. Introduction

Kern County prepared and circulated a Draft Environmental Impact Report 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 Environmental Impact Report (EIR) (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: (i) impacts to rangeland/grazing land, and (ii) impacts from road paving as a potential future measure to reduce designated air emissions in lieu of paying a portion of the required air mitigation measure fee. 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 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 on other issues. In October 2019, the Appellate Court rejected constitutional claims against the actual Ordinance amendments. On February 25, 2020, the Appellate Court issued an opinion concerning the California Environmental Quality Act (CEQA) challenges that upheld the Superior Court 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[1] 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.

1.1. Purpose

The purpose of this Supplemental Water Supply Baseline Technical Report is to provide information for the groundwater and water supply impact significance determinations for the Supplemental Recirculated Environmental Impact Report (SREIR) for reconsideration by Kern County for the adoption of the Zoning Ordinance (2020) for local permitting for oil and gas. It provides an update and background for revisions to the analysis of potential Project groundwater and water supply impacts for issues identified by the Appellate Court that were described in Chapter 4.9 (Hydrology and Water Quality) and Chapter 4.17 (Utilities and Service Systems) of the original 2015 FEIR. This report includes updates to the 2015 FEIR to incorporate new information identified by the Appellate Court, including the implementation of the Sustainable Groundwater Management Act (SGMA) in the Project Area since the original FEIR was certified.

[1] $PM_{2.5}$ = particulate matter up to 2.5 microns in diameter

It also includes review and analysis of the original 2015 FEIR water supply Mitigation Measures (MM) 4.17-2 to 4.17-4 that were originally proposed to reduce the Project's impacts on regional water supplies will also be addressed.

1.2. Summary of New Information

This report supplements the water supply analysis in the 2015 FEIR with the following new information:

- Updated information concerning the formation of Groundwater Sustainability Agencies (GSAs) and the adoption of Groundwater Sustainability Plans (GSPs) in the Project Area.
- Updated information concerning Project Area groundwater conditions and regional water supply and demand through the end of Water Year 2019 as summarized in the first annual report for the Kern County Subbasin (KCS) published on April 1, 2020 (KCGSAs 2020).
- Summaries of regional water supply and demand, and groundwater sustainability projections published for the KCS by the GSAs with statutory authority and obligations to prepare a consolidated water budget that incorporates multiple potential hydrological and climate change conditions from 2020 to 2070 under the SGMA.
- Summaries of the discussion of oil and gas activity in each of the five GSPs and 15 Management Area plans adopted for the KCS and the analysis of the relationship between these and the achievement of SGMA sustainable groundwater management requirements in each plan.
- Data for California oil and gas industry produced water generation and disposal and use of water supplies suitable for domestic or irrigation purposes, compiled by the state Department of Conservation, California Geologic and Energy Management Division (CalGEM) in quarterly water use reports for California.
- Summary of water well application information submitted to the County in accordance with the temporary provisions of the California Water Code effective from January 1, 2018, to January 30, 2020, to assist with the development of GSPs for critically overdrafted basins.
- Updated information concerning hydrological conditions since the end of the most recent drought in 2016 and new information concerning oil and gas activity in the County affected by state regulatory developments, the coronavirus pandemic and sharply declining oil prices in late 2019 and 2020.

2. Summary of 2015 Final Environmental Impact Report Water Supply Analysis

This section summarizes the analysis of groundwater and water supply impacts in the 2015 FEIR, which is incorporated as an appendix to the SREIR. Except where otherwise noted, all defined terms in this report, including "Project," "Project Area," and the "Western," "Eastern," and "Central" "Subareas," refer to the definitions of these terms in the 2015 FEIR.

Kern County accounts for about 80 percent of total California oil and gas production and is one of the largest oil and gas producing counties in the United States. 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. The 2015 FEIR estimated that 234,959 acre-feet per year (AFY) of produced water was extracted by oil and gas activities in the Project Area in 2012. The volume of produced water was projected to increase to 321,894 AFY in 2035 with the implementation of the Project. 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 was projected to increase to 121,412 AFY by 2035. Most of the produced water that is not needed for oil and gas activities is reinjected into the oil-bearing region from which it was extracted to maintain geologic stability in operating oil fields in accordance with applicable state and federal laws and regulations. Produced water has also been treated and blended with other water supplies for irrigation use by growers in the Project Area, particularly in the Eastern Subarea of the Project Area, adjacent to the Sierra Nevada foothills.

Certain oil and gas activities, such as new well construction, maintenance involving mud services, acidizing, coil tubing and well pulling, domestic water use by oil and gas personnel, well abandonment, and steam production require higher-quality water than can be obtained from produced water to meet environmental, health, and safety requirements or to avoid adverse chemical reactions. The 2015 FEIR estimated that 8,778 AFY of water suitable for domestic or irrigation purposes was used by oil and gas activities in the Project Area in 2012. The volume of domestic or irrigation-quality water used for oil and gas activities was projected to increase to 11,761 AFY in 2035, an increase of 2,983 AFY from 2012 levels. The analysis indicated that approximately 92 percent of all oil and gas industry water demand in the Project Area is met by reusing produced water, and about 8 percent of the industry’s total water demand uses water suitable for domestic or irrigation purposes.

To analyze potential groundwater and water supply impacts, the 2015 FEIR estimated and projected other domestic and irrigation-quality water use in the Project Area, including agricultural and urban use. Agricultural demand in the Project Area was estimated to be 2,635,916 AFY. Average Project Area urban demand was estimated to be 237,029 AFY in 2015, which would increase as urban areas and population grow to 301,736 AFY by 2035. These demands, plus domestic and irrigation water use by oil and gas activities, were compared with available and anticipated Project Area supplies during average, single dry, and multiple dry hydrologic years.

The Project Area uses surface water imported by the State Water Project (SWP), the federal Central Valley Project (CVP) and obtained from the Kern River and other local sources. The 2015 FEIR analysis considered the availability of these supplies during drier periods, when surface water deliveries would be reduced and as a result of regulatory constraints. The 2015 FEIR noted that, particularly in response to the state’s severe drought, groundwater extraction was increasing to compensate for reduced surface water supplies and depleting groundwater in the Project Area. At the time the 2015 FEIR was certified, the KCS designated by the California Department of Water Resources (DWR) extended to the southern boundaries of the Project Area, and the entire basin was designated as high priority and critically overdrafted. Under these conditions, the SGMA required that one or more GSAs be formed by June 30, 2017, to implement the SGMA in the basin. The GSAs were further required to adopt one or more GSPs covering the basin by January 31, 2020, and to achieve SGMA sustainable groundwater management requirements over the next 20 years. No GSAs had been formed and no GSPs adopted for the KCS by November 2015 when the FEIR was certified. For analysis purposes, the 2015 FEIR assumed that groundwater would be used in approximately the same average annual extraction volumes that had historically occurred in the Project Area, which were estimated to range from about 1.3 million AFY in average water years to 1.6 million AFY in drier years. The 2015 FEIR stated that groundwater use would likely vary under future conditions when GSPs were adopted and implemented in the region to meet SGMA requirements and that the estimated groundwater use in the analysis was not intended to represent the safe yield of regional aquifers. The analysis indicated that, if historical groundwater extractions were assumed to occur, domestic and irrigation water supplies would be sufficient to meet demand in average years, although the margin of supply relative to demand would fall over time. Even with continued historical levels of groundwater use, however, the analysis showed that significant domestic and irrigation water supply shortfalls would occur in single dry and multiple dry years. By 2035, the analysis indicated that demand for domestic and irrigation water would exceed supply by 817,127 AFY in a single dry year and up to 383,042 AFY during a multiple-year drought.

The oil and gas industry was estimated to account for about 0.34 percent of domestic and irrigation quality water use in 2015 and was projected to use 0.40 percent of total Project Area supplies in 2035 with the implementation of the Project. Due to increased groundwater use in response to constrained surface supplies, and SGMA sustainability requirements that could also constrain future groundwater use, the 2015 FEIR concluded that there was no surplus water available in the Project Area to meet domestic and irrigation demand. Any domestic and irrigation water use reduces potential supplies for other purposes and users. Consequently, although the oil and gas industry would use relatively small amounts of domestic and irrigation-quality water in the Project Area, the industry's projected demand was considered to be a significant impact on regional domestic and irrigation water supplies and groundwater.

The 2015 FEIR considered several potential mitigation measures that could reduce this impact to a less than significant level. Due to several technological and regulatory constraints, including potentially significant environmental impacts that could be associated with several possible measures, such as increased greenhouse gas emissions from produced water treatment and distribution, or concentrated treatment waste disposal, none would feasibly avoid impacts to groundwater and water supply. The 2015 FEIR included MMs 4.17-2 to 4.17-4 in an effort to reduce these impacts, primarily by encouraging oil and gas operators to develop methods for treating and reusing more produced water to meet oil and gas water needs or for other domestic or irrigation uses in conjunction with the pending implementation of the SGMA in the Project Area. Project impacts to groundwater and water supplies were, however, determined to be significant and unavoidable. In November 2015, the County Board of Supervisors adopted a Statement of Overriding Considerations for these impacts in conjunction with the certification of 2015 FEIR.

The Appellate Court subsequently found that MMs 4.17-2 to 4.17-4 violated CEQA because they did not require or result in specific, quantifiable reductions in oil and gas domestic and irrigation water use and that the Board of Supervisors thus lacked sufficient information concerning the net magnitude of the significant and unavoidable water supply impacts for which the Statement of Overriding Considerations was adopted. The Appellate Court directed the County to supplement the 2015 FEIR groundwater and water supply analysis with new information concerning SGMA implementation and groundwater conditions in the Project Area since the FEIR was certified and to reconsider the 2015 FEIR analysis of impacts to these resources if they move forward to reconsider adoption of the ordinance.

3. Updated Water Supply Regulatory Setting

This section updates the regulatory setting for the Project Area, including the adoption of SGMA emergency regulations by the DWR, the status of SGMA basin priority designations, GSA formation, and GSP adoption, and other regulatory changes affecting groundwater and water supply in the Project Area based on new information since November 2015.

3.1. Department of Water Resources Emergency Regulations Implementing the Sustainable Groundwater Management Act.

California enacted the SGMA (Water Code §10720 *et seq.*) in 2014. This act requires that all state groundwater subbasins designated as high priority or critically overdrafted by the DWR must be managed under a GSP, or a coordinated set of GSPs, by January 31, 2020. Subbasins designated as 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, with exclusive groundwater management authority in the GSA boundaries, and prepare and implement applicable GSPs. The SGMA does not apply to subbasins that are managed under a court-approved adjudication, or to low- or very low–priority subbasins (the SGMA allows lower priority basins to voluntarily form GSAs and implement GSPs). The purpose of a GSP is to ensure that, 20 years after adoption of the plan, the following “undesirable results” as defined in the SGMA 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.

SGMA Section 10727 provides that a GSP may be: (1) a single plan covering the entire basin developed and implemented by one GSA; (2) a single plan covering the entire basin developed and implemented by multiple GSAs or (3) subject to Water Code Section 10727.6, multiple plans implemented by multiple GSAs 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 the 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-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 the DWR in a subsequent rulemaking. For ease of reference, this report will refer to the currently applicable SGMA emergency regulations as the "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)-(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 first 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, inclusive. 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 whether the GSP is "approved," "incomplete" or "inadequate."

3.2. Sustainable Groundwater Management Act Prioritization, Groundwater Sustainability Agency Formation, and Groundwater Sustainability Plan Adoption in the Project Area.

As shown in Figure 1, DWR-designated groundwater subbasin 5-022.14, which is called the "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.

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 Louis Obispo County to the west.

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 (DWR 2020).

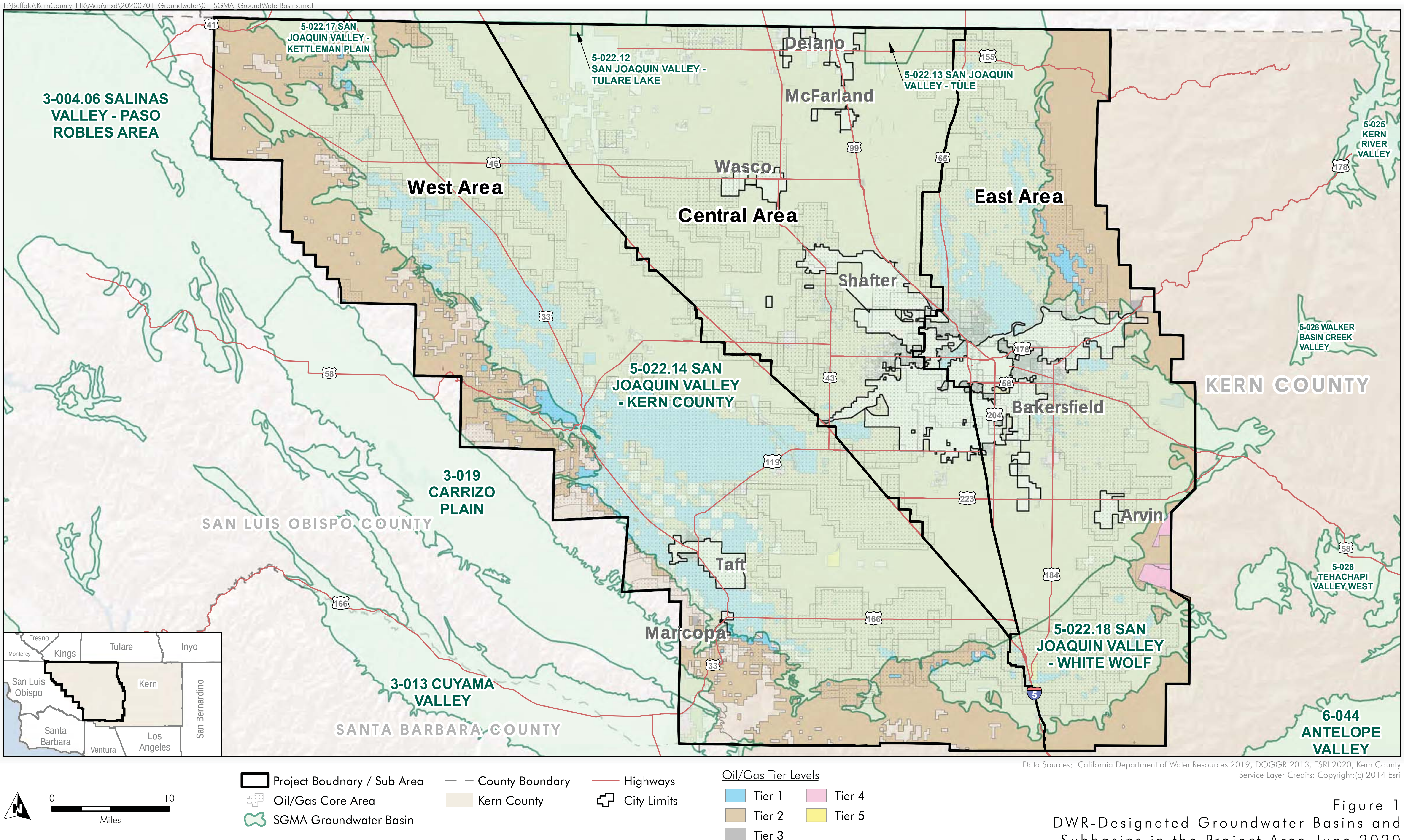

Figure 1
DWR-Designated Groundwater Basins and Subbasins in the Project Area June 2020

July 2020

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The SGMA requires that GSAs with exclusive jurisdiction over a basin or portion of a basin that they will regulate be created for high- and medium-priority basins by June 30, 2017. As shown in Figure 2, 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.

As shown in Figure 3, 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 no GSP has yet been adopted. No other GSPs are required in the Project Area under the SGMA.

3.3. Project Area Groundwater Sustainability Plans, Administrative Oil Fields, and Core Areas

The GSPs for the Tule subbasin, the Tulare Lake subbasin, and the Cuyama Valley basin 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 in the Project Area 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.

A small portion of the low-priority Carizzo Plain basin extends into the southwest portion of the Project Area. 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. 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 activity has historically occurred in the Kettleman Plain subbasin for several years. The Kettleman Plain basin is designated by the DWR as lower priority and does not require a GSP; no GSA has been formed for the potential development of a GSP in accordance with the SGMA.

As shown in Figure 1, 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 Subareas. The basin has been designated as high priority and critically overdrafted by the DWR. As required by SGMA, 11 GSAs were formed in 2017 for the KCS: the Cawelo GSA, the Kern Groundwater Authority GSA, the McFarland GSA, the Pioneer GSA, the Semitropic Water Storage District (SWSD) GSA, the West Kern Water District (WKWD) GSA, the Greenfield County Water District GSA, the Kern River GSA, the Olcese GSA, the Buena Vista Water Storage District GSA, and the Henry Miller Water District GSA (see Figure 2).

As shown in Figure 3, 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 Kern Groundwater Authority GSP (KGAGSP), which includes about 1.2 million acres of the KCS. The second largest

GSP is the Kern River GSP (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 plan area is located to the west of the KRGSP planning area 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 area is located on the eastern edge of the Eastern Subarea near the Kern River.

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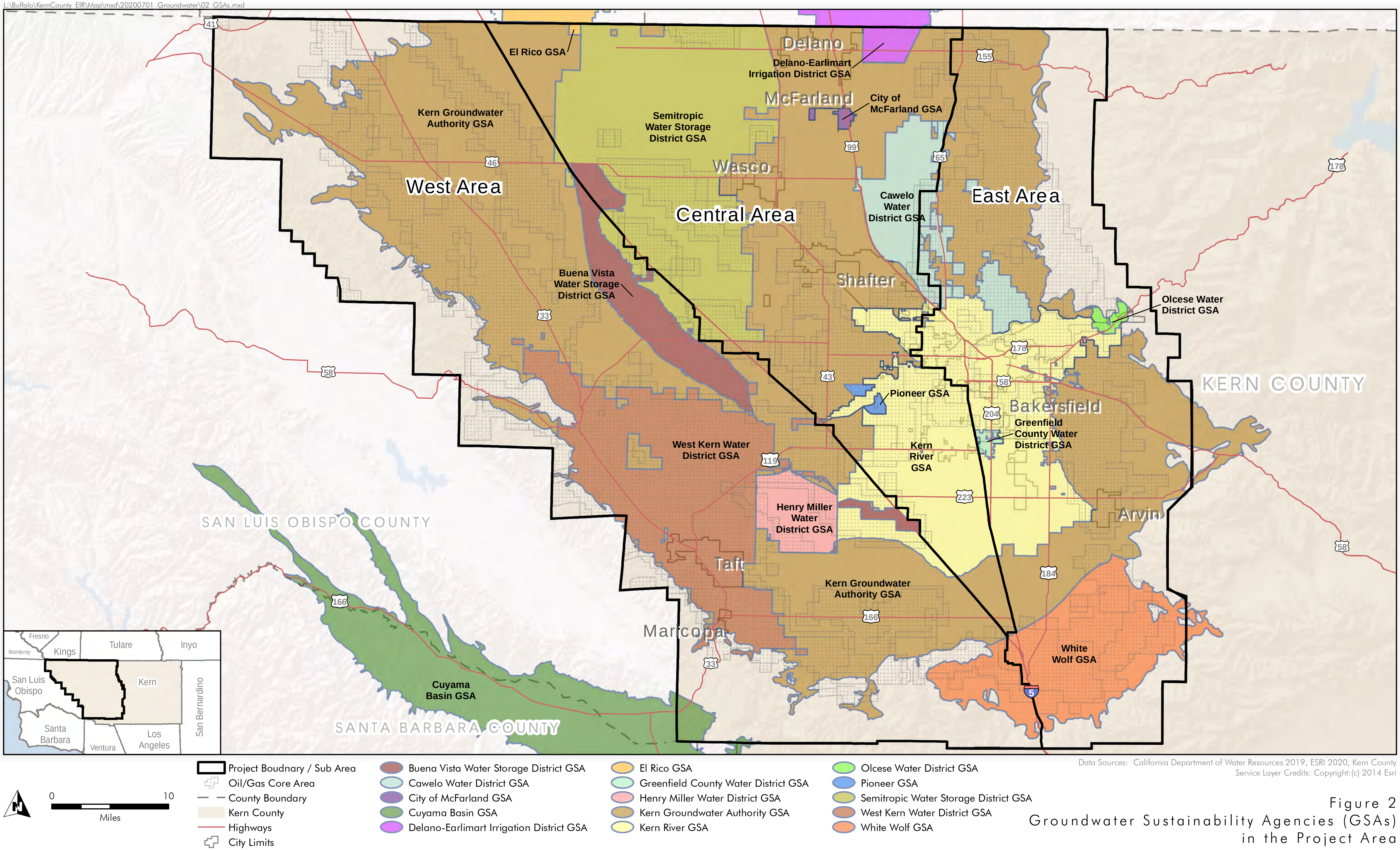

Figure 2
Groundwater Sustainability Agencies (GSAs) in the Project Area

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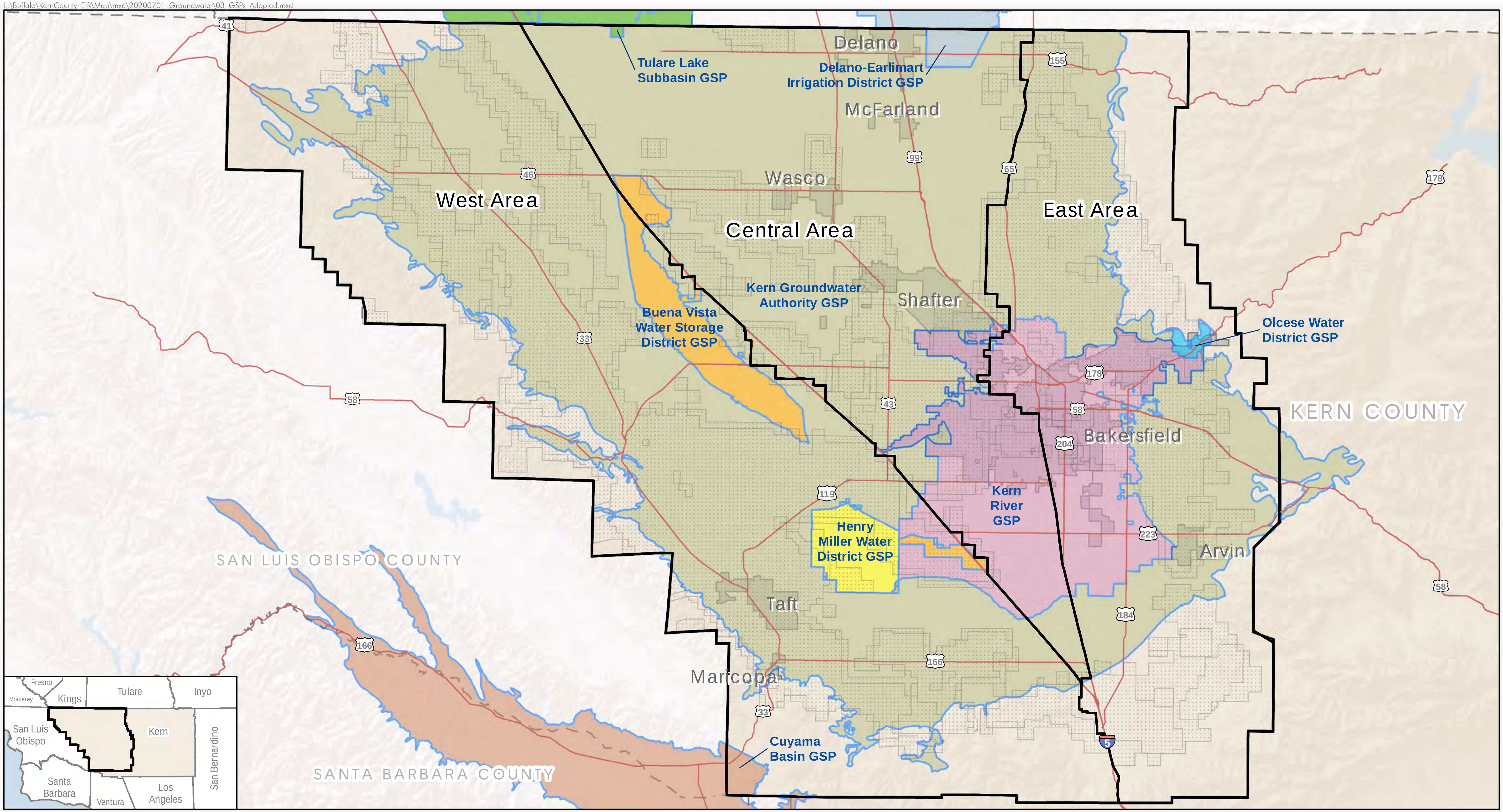

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Miles

Project Boundary / Sub ARea
County Boundary
Kern County
Oil/Gas Core Area
Highways
City Limits

Groundwater Sustainability Plans (GSP) Adopted
Buena Vista Water Storage District GSP
Cuyama Basin GSP
Delano-Earlimart Irrigation District GSP
Henry Miller Water District GSP
Kern River GSP
Kern Groundwater Authority GSP
Olcese Water District GSP
Tulare Lake Subbasin GSP

Data Sources: California Department of Water Resources 2019, DOGGR 2013, ESRI 2020, Kern County
Service Layer Credits: Copyright:(c) 2014 Esri

Figure 3
Adopted Groundwater Sustainability Plans (GSPs) in the Project Area

July 2020

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Consistent with Section 354.20 of the SGMA regulations, 15 Management Area Plans have been prepared in conjunction with the KGAGSP. The management areas were created by water districts and member agencies under the KGA to support groundwater sustainability in the SKCS. 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 KGAGSP 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 KGAGSP are listed below:

- Arvin-Edison Water Storage District (AEWSD) Management Area Plan (EKI Environment & Water 2019a)
- Cawelo GSA Management Area Plan (Cawelo GSA 2019)
- Eastside Water Management Area (EWMA) Plan (EKI Environment & Water 2019b)
- Kern County Water Agency – Pioneer Project Plan (Woodard & Curran 2019a)
- Kern Water Bank Authority (KWBA) GSP (Parker 2019)
- Kern-Tulare Water District (KTWD) Management Area Plan (KTWD 2019)
- North Kern Water Storage District (NKWSD)- Shafter-Wasco Irrigation District (SWID) Management Area Plan (GEI Consultants 2019a)
- Rosedale-Rio Bravo Management Area Plan (KGA 2019)
- SWSD GSA Management Area Plan (GEI Consultants 2019b)
- SWID 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 (TCWD) Management Area Plan (EKI Environment & Water 2019d)
- WKWD Management Area Plan (Woodard & Curran 2019b)
- Westside District Water Authority (WDWA) Management Area Plan (Aquilogic, Inc. 2019)
- Wheeler Ridge-Maricopa Water Storage District Management Area Plan (EKI Environment & Water 2019e)

Figure 4 shows the locations of the KGA member agencies included in the 15 Management Area Plans. The KGAGSP and the KGA Management Area Plans include most of the Project Area in the KCS subject to County jurisdiction.

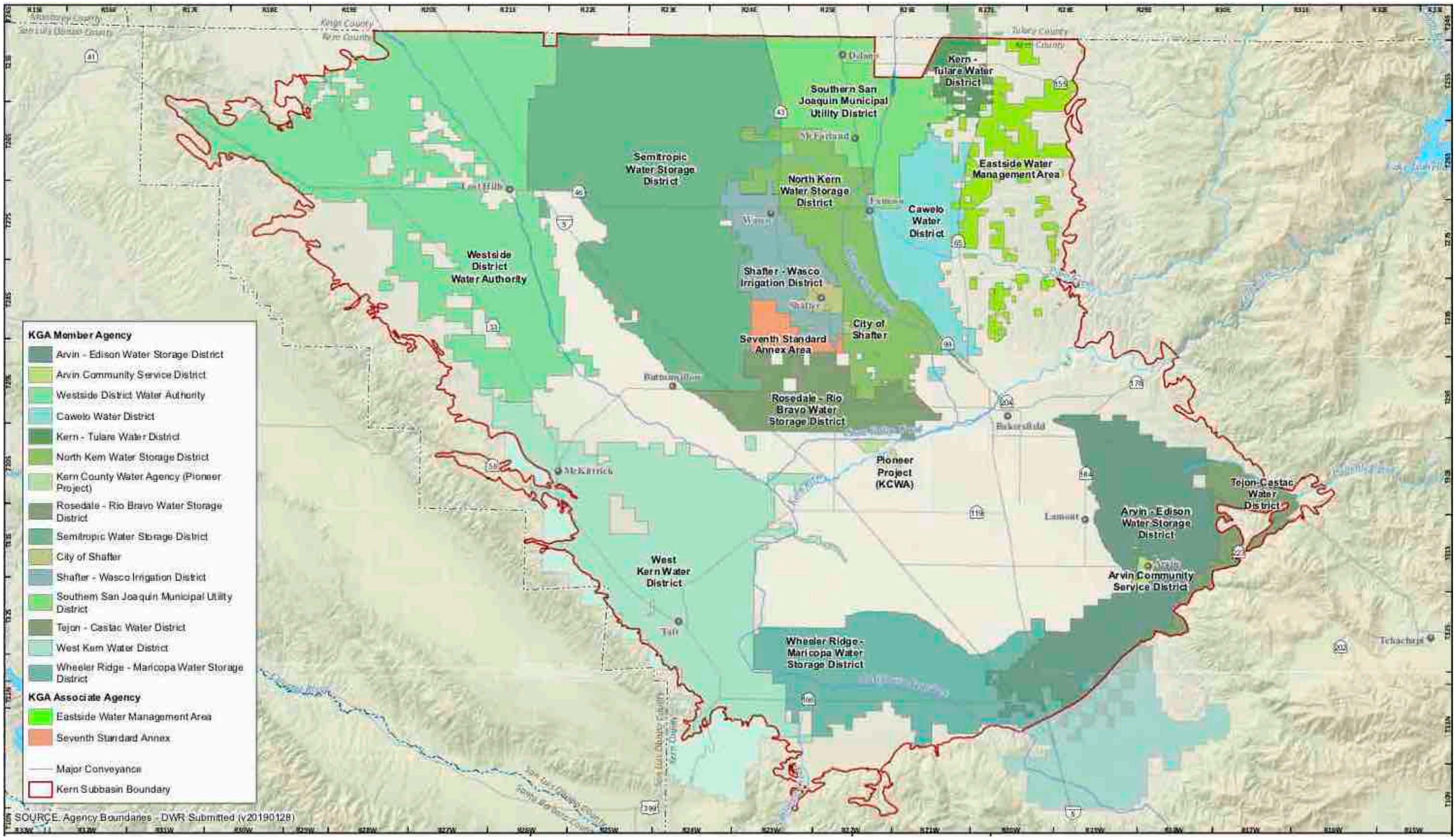

Figure 4 **Locations of KGAGSP Member Agencies (KGA 2020)**

The 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 area 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 Kern County Water Agency subsequently extended SGMA coverage by means of landowner agreements to approximately 242,180 acres of non-districted lands in the HCS. The KGAGSP 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 KGAGSP 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 the SGMA (KGA 2020).

The GSPs were adopted and submitted to the DWR by January 31, 2020, in accordance with SGMA. The DWR maintains an online website (the "SGMA Portal") that provides current information about GSAs, GSPs, and other SGMA information. The SGMA 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 as yet been approved by the DWR in accordance with the SGMA regulations.

3.4. Kern County Subbasin Coordination Agreement and Coordinated Water Budget

As required by the SGMA and the 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 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 Coordination Agreement, and the coordinated KCS water budget were submitted to the DWR in accordance with Section 357.4(g) of the SGMA regulations. The SGMA Portal does not include additional information about the status of the Agreement.

3.5 Kern County Subbasin Annual Report.

As required by Section 356.2 of the SGMA regulations, the first annual report for the KCS was submitted by the GSAs to the DWR on April 1, 2020 (the "Annual Report") (KCGSAs 2020). The SGMA Portal does not include additional information about the status of the Annual Report.

3.6. Water Well Application Requirements in Critically Overdrafted Basins

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) required that water well applicants provide information concerning the location, depth, and proposed capacity of the well; estimated pumping rates; anticipated pumping schedules; 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 required 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.

3.7. Underground Injection Control Program Status and Regulatory Update

As discussed in the 2015 FEIR, under the federal Safe Drinking Water Act (SDWA) the U.S. Environmental Protection Agency (EPA) may allow for the subsurface injection of fluids below, into, and above an underground source of drinking water (USDW) pursuant to federal underground injection control (UIC) regulations (40 Code of Federal Regulations [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 milligrams per liter (mg/L) of total dissolved solids (TDS). The UIC regulations cover six classes of injection wells. Class II wells inject fluids associated with oil and natural gas production operations, including the disposal of briny produced water in deep underground formations to prevent surface contamination of soil.

For oil and gas production and Class II well operations, an aquifer that otherwise meets the definition of a USDW may be designated as "exempted" and be used for subsurface injection under the UIC program. To be exempted, an aquifer must be determined to 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 that 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, the UIC regulations provide that an aquifer may be exempted from SDWA protection if the TDS content of the ground water 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 to be USDWs under federal law and do not need to be exempted for injection to occur (40 CFR 146.4).

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. Effective January 1, 2020, the Division of Oil, Gas, and Geothermal Resources (DOGGR), which regulated oil and gas activity and the UIC program in California, was replaced by the California Geologic Energy Management Division (CalGEM) of the California Department of Conservation (DOC 2020). For ease of reference, "CalGEM" in this report includes actions taken by or documents referencing DOGGR that occurred prior to the formation of CalGEM. CalGEM regulates the UIC program in California under a memorandum of agreement initially executed in 1982 with the EPA. The memorandum of agreement, including UIC program and aquifer exemption procedures, was revised in July 2018 by CalGEM and the EPA (DOGGR 2018). The state adopted updated UIC regulations effective April 1, 2019 (CCR Section 1721 et seq). According to CalGEM, key elements in the updated regulations include: stronger testing requirements designed to identify potential leaks; increased data requirements to ensure that 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 (CalGEM 2019).

Section 1721(n) of the updated 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 updated 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. One surface expression resulted in the discharge of 31,798 barrels of oil and produced water in the Cymric oil field in 2019, the largest since 1990. Governor Gavin Newsom visited the site of this expression on July 24, 2019. CalGEM maintains an online tracking summary of surface expressions subject to updated Section 1724.11(a) of the UIC regulations. According to CalGEM, the Cymric expression cleanup was completed on October 11, 2019, and resulted in the imposition of a civil fine of more than $2.7 million. In June 2020 the CalGEM tracking summary stated that "The 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 2019b).

As discussed in the 2015 FEIR, as a result of a permitting review process initiated in 2011, state and federal regulators identified several permitted Class II injection wells in California that could be discharging fluids into aquifers that met the criteria for a USDW but were potentially not exempted under the UIC. By 2015, the state and the EPA developed a process for identifying and evaluating any such class II wells. If an aquifer exemption was required, the program would either document and process aquifer exemptions for approval by the EPA or shift injection to other exempted or non-USDW aquifers.

On March 23, 2020, CalGEM and the State Water Resources Control Board 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 Water Resources Control 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 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 2019b).

As discussed in the 2015 FEIR, 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, the Superior Court's decision was upheld by the California Court of Appeal, which also denied a 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).

4. Updated Environmental Setting

This section updates the environmental setting for the Project Area, including water supply and demand and groundwater information in the Annual Report (KCGSAs 2020), the water budget analysis and scenario results for the KCS over the 2020 to 2070 planning and implementation horizon mandated by the SGMA, oil and gas industry references in the five GSPs and 15 Management Area Plans for the KCS, oil and gas water use reports published by CalGEM, oil and gas–related permitting, and economic and fiscal conditions in the County.

4.1. 2016–2019 Hydrological and Groundwater Conditions.

The National Integrated Drought Information System publishes the U.S. Drought Monitor (USDM), which 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," and "Moderate" (D1), "Severe" (D2), "Extreme" (D3) and "Exceptional" (D4) drought conditions. The USDM has been maintained since 2000. Figure 4 shows the USDM summary of the percentage of the total land area of California in no drought, D0 drought precursor, and D1 to D4 drought conditions. 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 to D4 drought conditions. As discussed in the 2015 FEIR, the state experienced a prolonged period of exceptional drought, which peaked in July 2014 when more than 58 percent of California was in D4 condition. No part of the state has been in D4 condition since 2017. As discussed in the 2018 SEIR, California is inherently subject to varying periods of wetter, drier, and severely dry hydrology. Historically severe floods occurred in 1861 to 1862, over 150 years ago, 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).

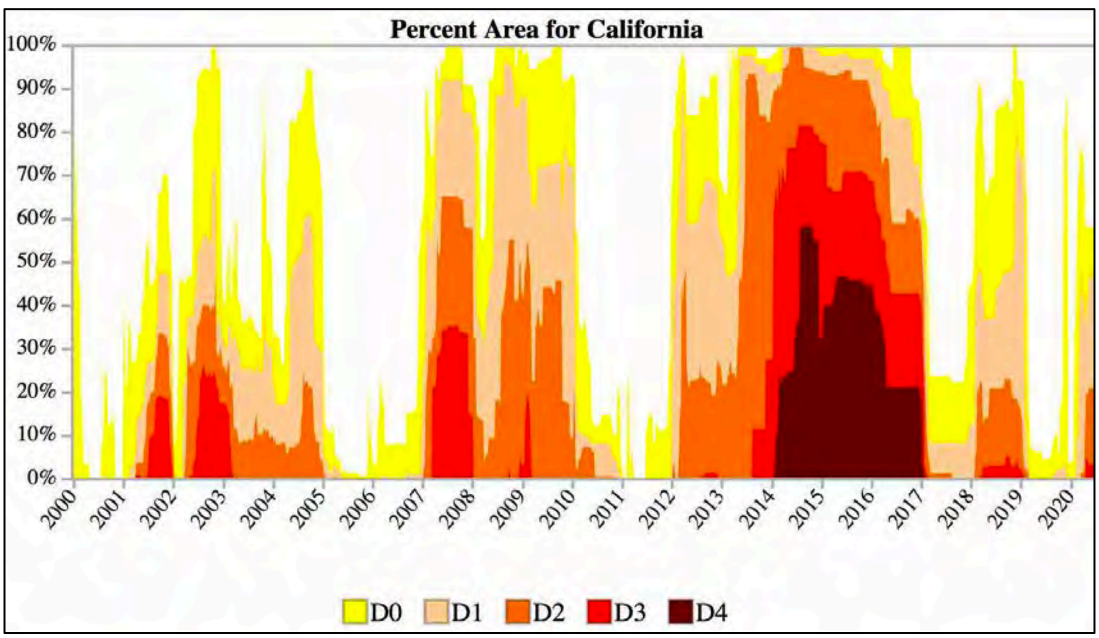

Figure 5 U.S. Drought Monitor for California

Since 2017, no part of the state has been in an exceptional drought (D4). In June 2020 the USDW stated that about 17.8 percent of California was in D2 condition, and 3 percent was in D3 condition. All of these locations extended north from the San Francisco Bay Area to the Oregon border. The USDW indicated that 25 percent of the state was in D1 condition and 11.5 percent was considered to be abnormally dry. All of these locations were north of the Project Area. As shown in Figure 4, 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).

The Annual Report provides groundwater storage information for the KCS from 2016 to 2019 that is consistent with the significant improvement in the state's 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 groundwater in storage declined by 1,229,970 acre-feet. 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).

4.2. Water Year 2019 Demand and Supply in the Kern County Subbasin.

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, 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 acre-feet, 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. (KCSGSAs 2020).

The Annual Report estimates that 2,805,400 acre-feet of surface water was used in the KCS area during water year 2019, including 1,627,026 acre-feet of imported federal CVP and SWP supplies, 1,065,772 acre-feet of local surface water, and 37,133 acre-feet of recycled and "other" supplies. The Annual Report states that 75,469 acre-feet 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 acre-feet. (KCGSAs 2020)

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 acre-feet. Urban use, including oil and gas activities, was estimated to be about 199,977 acre-feet. Agricultural use was estimated to be about 2,445,679 acre-feet. Other water uses included managed wetlands (23,074 acre-feet), managed groundwater recharge (1,173,060 acre-feet) and other demand (36,512 acre-feet). (KCGSAs 2020)

4.3. Coordinated Kern County Subbasin Water Budget and 2020–2070 Projections.

As discussed above, in January 2020 the KCS GSAs executed a Coordination Agreement and prepared a coordinated water budget in accordance with Section 357.4 of the SGMA regulations. 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 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 then analyzed by using a representative series of wet and dry conditions for the region and by adjusting surface water availability levels to reflect regulatory and climate change constraints under varying 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 a 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 percent and 6 percent from the baseline scenario assumptions (KGA 2020).

The coordinated water budget analysis of the three 2021 to 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. As discussed in more detail below, 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).

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 rage of plus or minus 10 percent. The analysis results for 2020 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 average annual change 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 1 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 to surface supply reductions. In very wet years, such as 2029 and 2049, 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 to 2070 sustainability period.

Table 1 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
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

Table 1 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
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
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 2 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 to 2070 sustainability period.

Table 2 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
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

Table 2 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
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
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 3 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 2041to 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 the excess outflow adjustments.

Table 3 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 for the 2041-2070 SGMA Compliance Period

	Change in Groundwater Storage (acre-feet per year)	
	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

4.4. Oil and Gas Activity and Groundwater Sustainability Plans and Management Area Implementation

This section summarizes the discussion of oil and gas activities in the five GSPs and 15 Management Area Plans that have been adopted for the KCS. As discussed above, the GSPs and Management Area Plans must collectively avoid undesirable results and achieve sustainable groundwater management in the KCS by 2040. The coordinated water budget indicates that proposed SGMA Projects must be implemented in the KCS to achieve these objectives. 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 met. Each GSP and Management Area Plan provides significant information concerning KCS conditions and future planning for discrete portions of the Project Area that correspond with historically defined water districts and water management operations. As a result, the discussion of oil and gas activities in each GSP and Management Area Plan indicates the extent to which the primary KCS water managers, and the professional geologists and engineers who developed the plans, anticipate that oil and gas operations could affect the achievement of SGMA sustainability goals within well-defined, historically established, and operating water districts and water management portions of the Project Area.

The KCS is an inland subbasin, and the SGMA-defined undesirable result involving seawater intrusion is not applicable to the subbasin. The SGMA-defined undesirable results that must be avoided by 2040 in the KCS are "(1) chronic lowering of groundwater levels; (2) significant and unreasonable reductions in groundwater storage; (3) significant and unreasonable degradation of water quality; (4) significant and unreasonable land subsidence; and (5) surface water depletions that have significant and unreasonable adverse impacts on beneficial uses." The following discussion summarizes the discussion of these concerns with respect to oil and gas activities in each of the GSPs and Management Area Plans adopted for the KCS.

4.4.1 Kern Groundwater Authority Groundwater Sustainability Plan and Management Area Plans

The KGAGSP is an "umbrella" GSP that covers approximately 1.2 million acres of the KCS and includes 15 Management Area Plans. The locations of the Management Area plans are shown in Figure 4 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 KGAGSP 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 KGAGSP 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" (KGA 2020)

The KGAGSP 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 U.S. Geological Survey (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." (KGA 2020)

The plan considered 264 permitted sites that could affect water quality, including sites for which Waste Discharge Requirements 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 KGAGSP 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." 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 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 aquifer exemption program. As discussed above, CalGEM and the EPA are implementing a process for addressing permitted wells in California that may be discharging fluids into USDWs that have not been exempted under the UIC program. From 2017 to 2020, the EPA approved 20 aquifer exemptions, including several within the Project Area and including 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 2020).

Petroleum reservoir compaction due to oil and gas withdrawal is identified in the KGAGSP 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 that 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) take action 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 KGAGSP 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 KGAGSP involve additional development and use of produced water for domestic or irrigation purposes. KGA members that proposed to use produced water to meet SGMA objectives for the KCS include that the AEWSD, the Cawelo Water Storage District, the EWMA, the NKWSD, and the districts in the WDWA. The following sections discuss oil and gas activity references in each of the 15 Management Area plans adopted within the KGA and included in the KGAGSP.

4.4.1.1 Northeastern Management Areas in the Kern Groundwater Authority Groundwater Sustainability Plan

The EWMA Plan, Cawelo GSA Management Area Plan, and KTWD Area Plan overlie the Eastern Subarea and the Central Subarea in the northeastern portions of the Project.

Eastside Water Management Area Plan

The EWMA Plan is the most easterly of the three northeastern Management Areas and encompasses approximately 35,000 non-contiguous 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 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, as summarized in a March 2020 letter from CalGEM to the EPA concerning the state's aquifer exemption program, certain "AE's are under review and subject to change in the near future." (EKI Environment & Water 2019b)

Appendix B of the plan, 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 Management Area 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 Kern-Tulare Water District (discussed below). 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 "is currently looking at historic ponds and requesting investigation where appropriate" (EKI Environment & Water 2019b)

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 Cawelo Water District (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…." (Cawelo GSA 2019)

The plan further states that "water supply wells in the CWD 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)

Treated oilfield water used by the CWD "is sampled monthly at Reservoir B for agricultural suitability" and the CWD provides water quality reports prepared by the treated oilfield 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." (Cawelo GSA 2019)

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. (Cawelo GSA 2019)

The 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 KGAGSP, 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." (Cawelo GSA 2019)

Table 4-1 of the plan states that a total of 481,880 acre-feet of treated oilfield-produced water was imported into and used in the CWD from 1995 to 2014. A total of 86,863 acre-feet was imported and beneficially used from 2015 to 2017. The plan discusses the future use of produced water over the 2020 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)

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 fresh water 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 [oilfield 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 $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 coordinated water budget for 2020 to 2070.

The Kern-Tulare Water District Management Area Plan

The KTWD Management Area Plan was prepared by the KTWD and includes of 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 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." (KTWD 2019)

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." (KTWD 2019)

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.

4.4.1.2 Southeastern Management Areas in the Kern Groundwater Authority GSP

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.

Arvin-Edison Water Storage District 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. It 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." (EKI Environment & Water 2019a)

Section 17 of the plan, List of Projects and Management Actions, 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” and could augment available supplies by 1,000 AFY. A feasibility study for the reclamation of oilfield produced water project would be implemented during the first five years of the plan. (EKI Environment & Water 2019a)

Tejon-Castac Water District 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-regulated 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 2019d)

4.4.1.3 Central Management Areas in the Kern Groundwater Authority Groundwater Sustainability Plan

The plan areas for the Kern County Water Agency - Pioneer Project Management Area Plan, KWBA 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.

Kern County Water Agency - Pioneer Project Management Area Plan

The Kern County Water Agency - 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)

The Kern Water Bank Authority Management Area Plan

The KWBA Management Area Plan project area consists of 20,480 acres, or 32 square miles owned by the KWBA southwest of the City of Bakersfield along the Kern River. The Kern Water Bank 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 "[s]cattered 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." It 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)

North Kern Water Storage District - Shafter-Wasco Irrigation District Management Area Plan

The NKWSD - SWID Management Area Plan was developed under a cooperative agreement between the NKWSD, SWID, City of Shafter, and 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 also serves the approximately 10,000-acre Rosedale Ranch Improvement District (RRID). The service area for the 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 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." (GEI Consultants 2019a)

The plan also 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." (GEI Consultants 2019a)

In 2015, the NKWSD entered into an agreement with the CRC for the delivery of 11,700 to 21,200 AFY oilfield-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. The plan's Table 5-1, "Proposed list of Projects and Management Actions for North Kern Water Storage District" 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 RRID benefit." The amount of water supply augmentation and ongoing annual costs of this SGMA Project are not identified. (GEI Consultants 2019a)

Shafter-Wasco Irrigation District 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 "[t]aken 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 "[b]ased 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 2019c)

Southern San Joaquin Municipal Utility District Management Area Plan

The Southern San Joaquin Municipal Utility District Management Area Plan covers 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 KCS "are constrained by the primacy productive limits with depths to hydrocarbons, and aquifer exemptions with corresponding depths" but 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 2019c)

Semitropic Water Storage District 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 2019b)

Rosedale-Rio Bravo Management Area Plan

The Rosedale-Rio Bravo Management Area 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 (MOU). The MOU 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)

4.4.1.4 Western Management Areas in the Kern Groundwater Authority Groundwater Sustainability Plan

The plan areas for WKWD Management Area Plan, the WDWA Management Area Plan, and the Wheeler Ridge-Maricopa Water Storage District Management Area Plan are primarily located in the west of the KGAGSP area and in the Western Subarea of the Project Area. Portions of the Wheeler Ridge-Maricopa Water Storage District 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 Management Area is located in the southern half of the Western Subarea of the Project Area and includes the WKWD boundary and adjacent oilfield 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 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 KGAGSP. 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.” (Woodard & Curran 2019b)

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 also 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 the 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.” It states that the 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).” (Woodard & Curran 2019b)

The plan references the same list of potential water quality impact sites as Figure 2-26 of the KGAGSP, which includes 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, “[o]ilfield 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)

Westside District Water Authority Management Area Plan

The WDWA Management Area Plan area 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 (BMWD) and the Belridge Water Storage District (BWSD). The plan indicates that these districts primarily provide SWP surface water for agricultural irrigation. Regarding 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." Regarding 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. (Aquilogic 2019)

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 is estimated in the plan to be approximately 3,000 AFY. (Aquilogic 2019)

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 that:

> “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” ((Aquilogic 2019)).

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 that:

> “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)

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." (Aquilogic 2019)

The plan discusses produced water disposal ponds in the LHWD area, and states that 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)

The plan also addresses produced water ponds and groundwater in the BWSD area. It discusses regulated water quality "events" and, where applicable, enforcement orders associated with three oil and gas–related sites, known as "Aera Energy's former South Belridge Oil Field Ponds; Exxon/Mobil Hill Lease; and Valley Water Management Ponds." The plan states that, consistent:

> "with the totality of other data sets…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 KGAGSP as open and having potential or confirmed groundwater quality impacts. (Aquilogic 2019)

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 satellite-based Interferometer Synthetic Aperture Radar (InSAR). 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 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 further 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." (Aquilogic 2019)

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." (Aquilogic 2019)

The plan identifies SGMA "Planning and Management Actions" (PMAs). PMA No. 3 is the "Conjunctive Reuse of Naturally Degraded Brackish Groundwater" and focuses on the "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 2019)

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." (Aquilogic 2019)

Wheeler Ridge-Maricopa Water Storage District Management Area Plan

The Wheeler Ridge-Maricopa Water Storage District 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" 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. (EKI Environment & Water 2019e)

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 that 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." It further 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)

4.4.2 Kern River Groundwater Sustainability Plan

The KRGSP area 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 that the plan area:

> "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." (KRGSA 2020)

The plan states that "Because 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." (KRGSA 2020)

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 [leaking underground storage tank] sites." (KRGSA 2020)

4.4.3. Henry Miller Water District Groundwater Sustainability Agency Groundwater Sustainability Plan

The Henry Miller Water District (HMWD) GSA GSP area 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 KGAGSP. 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 that:

> "[w]ater 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." (Luhdorff & Scalmanini 2020)

The plan also includes a discussion of oil and gas subsidence that is substantially similar to the KGAGSP 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 HMWDGSP 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 (Lhdorff & Scalmanini 2020). The wells are mapped from a 2015 list provided to the EPA by the state in conjunction with the UIC program. As discussed above, CalGEM and the EPA have been implementing a process for addressing permitted wells in California that may be discharging fluids into USDWs that have not been exempted under the UIC program. From 2017 to 2020, the EPA approved 20 aquifer exemptions, including several of the locations in Figure 2-39. Several other aquifer exemption proposals are being reviewed and considered by CalGEM, including locations in the Project Area (CalGEM 2020).

The plan considered the same 264 permitted sites that could affect water quality as discussed in the KGAGSP, including sites for which Waste Discharge Requirements 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"

4.4.4. Olcese Water District Groundwater Sustainability Agency Groundwater Sustainability Plan

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.'" (EKI Environment & Water 2020)

The plan states that under Section 354.26(b)(1)) of the SGMA regulations:

> "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 "Direct injection of fluids associated with oil and natural gas production via Class II wells under the UIC program is regulated under the SDWA 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)

4.4.5. Buena Vista Water Storage District Groundwater Sustainability Agency Groundwater Sustainability Plan

The Buena Vista Water Storage District GSA (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 "Several 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, "One 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." (BVWSD GSA 2020)

Figure 2-28 of the plan identifies 77 “Sites Of Potential Groundwater Impacts,” which are substantially similar to the 77 sites discussed in the KGAGSP and the HMWDGSP. Some of the mapped sites are produced water ponds. None of the sites are shown in Figure 2-28 as lying 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)

4.5. Oil and Gas Water Use and Senate Bill 1281 Reports for 2015 to 2017.

As discussed in the 2015 FEIR, SB 1281 amended California Public Resources Code Section 3227 in 2014. The amendments require that oil and gas well operators provide a monthly statement and a more detailed quarterly report of water use to CalGEM. The monthly statement must identify the disposition of produced water. The quarterly report must also identify the sources and volumes of water used, water treatment methods, and disposal methods for injection, noninjection, and storage purposes. The reports must quantify the amount of “water suitable for domestic or irrigation purposes” used by oil and gas operators. In August 2015 the State Water Resources Control Board stated in a letter to CalGEM 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 mg/l or lower (CalGEM 2019c).

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 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. 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 2019d). The 2015 FEIR discussed the quarterly water use report prepared by CalGEM for the first quarter of 2015, the report available at the time the 2015 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 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 indicates that state oil and gas operators generated an average of just over 103,000 acre-feet of produced water per quarter from the second quarter of 2015 to the second quarter of 2017. An average of 3,539 acre-feet per quarter of produced water was reported as suitable for domestic or irrigation use. An average of 8,991 acre-feet of produced water per quarter was sold or transferred for domestic use.

Table 4 Volume of Produced Water, Produced Water Suitable for Domestic or Irrigation Use, and Produced Water Sold or Transferred for Domestic Use, SB 1281 Quarterly State Water Use Reports (acre-feet)

	Total	Portion Suitable for Domestic or Irrigation Use	Sale/Transfer for Domestic Use
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

Table 5 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 5 indicates that state oil and gas operators injected an average of 88,868 acre-feet 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 acre-feet per quarter of the total injected volume was reported as suitable for domestic or irrigation use.

Table 5 Volume of Injection and Portion Suitable for Domestic or Irrigation Use SB 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

Table 5 Volume of Injection and Portion Suitable for Domestic or Irrigation Use SB 1281 Quarterly State Water Use Reports (acre feet)

	Total	Portion Suitable for Domestic or Irrigation Use
2016 Q3	92,802	1,107
2016 Q4	87,978	1,404
2017 Q1	88,751	1,711
2017 Q2	88,316	1,403
Quarterly Average	88,868	1,550

Table 6 summarizes the quarterly volume of storage and non-injection fluids, 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 6 indicates that oil and gas operators within the state reported an average of 4,944 acre-feet 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 acre-feet per quarter of the total storage and non-injection water volume was suitable for domestic or irrigation use.

Table 6 Volume of Storage and Non-Injection Fluids and Portion Suitable for Domestic or Irrigation Use, SB 1281 Quarterly State Water Use Reports (acre feet)

	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

4.6. Updated Oil and Gas Industry Conditions in Kern County

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 at 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 -$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 spring 2020 coronavirus outbreak 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).

5. Updated California Environmental Quality Act Analysis

This section updates the analysis of the Project's potential impacts to groundwater and water supply in the 2015 FEIR to include the new information summarized above and to reconsider feasible mitigation for impacts determined to be significant. The CEQA Appendix G Checklist and the Notice of Preparation for this Project state that a project would have a significant impact on hydrology, water quality and water supply if it would:

(1) Substantially decrease groundwater supplies or interfere substantially with groundwater recharge such that the project may impede sustainable groundwater management of the basin;

(2) Conflict with or obstruct implementation of a water quality control plan or sustainable groundwater management plan; and

(3) Have insufficient water supplies available to serve the project and reasonably foreseeable future development during normal, dry and multiple dry years.

As discussed in the Notice of Preparation (NOP) (Kern County Planning and Natural Resources Department 2020), the SREIR will consider whether new or revised mitigation measures can be feasibly implemented to reduce potentially significant groundwater or water supply impacts. The CEQA Appendix G Checklist and the Notice of Preparation for this Project state that a project would have a significant impact on hydrology, water quality and water supply if such mitigation measures would require or result in the relocation or construction of new or expanded water facilities, the construction or relocation of which could cause significant environmental effects.

5.1 Would the Project substantially decrease groundwater supplies or interfere substantially with groundwater recharge such that the project may impede sustainable groundwater management of the basin?

The new information concerning Project Area groundwater conditions, including the groundwater basin boundary modifications approved by the DWR, the formation of GSAs, and the adoption of GSPs and Management Area plans; other information, such as the Annual Report related to SGMA implementation and water use reports published by CalGEM since the second quarter of 2015; and oil and gas permitting and industry conditions since the 2015 FEIR was issued does not significantly affect the analysis of potential oil and gas industry groundwater use impacts in the 2015 FEIR. The new information does provide significant substantial evidence that oil and gas activities affecting groundwater occur outside of the aquifers subject to the SGMA, that the reuse of produced water for domestic or irrigation purposes in the Project Area constitutes a new locally imported supply into aquifers subject to the SGMA, and that GSPs and Management Area plans adopted in accordance with the SGMA include produced water reuse in the SGMA Projects that would implemented by GSAs in the Project Area to achieve sustainable groundwater management by 2040 as required by the SGMA.

The 2015 FEIR determined that almost all of the water used for oil and gas operations in the Project Area was obtained from produced water. Certain oil and gas activities required the use of domestic or irrigation quality water, including well construction and abandonment in accordance with applicable laws and regulations, and activities with high corrosion risks or during which adverse chemical reactions could occur from the use of lower quality water. In 2012, oil and gas activities used 8,778 AFY of domestic or irrigation quality water and demand for these sources was projected to increase to 11,761 AFY in 2035, a net change of 2,983 AFY. Although oil and gas water use of this magnitude would account for significantly less than 1 percent of total current and projected future domestic and irrigation quality water demand in the Project Area, the 2015 FEIR discussed several factors, including current and future surface supply limitations and historical groundwater overdraft subject to the SGMA, that constrained high quality water supply and concluded that there was no surplus water available in the Project Area. Consequently, oil and gas consumption of domestic and irrigation quality water, which was conservatively assumed to be supplied by groundwater, was determined to be a significant groundwater impact and to contribute to cumulatively significant sustainable groundwater management impacts.

New groundwater information is consistent with the FEIR analysis. 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 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 Environment & Water 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. 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 KGAGSP, 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 exempt aquifers under the UIC program from the lateral and vertical boundaries of the groundwater subbasin in the KCS. The KGAGSP, 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 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 (GEI Consultants 2019b). 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 oilfield. 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 2019b). There is no substantial evidence that oil and gas activities would cause significant new or significantly greater impacts to groundwater quality in the Project Area than considered in the 2015 FEIR.

The GSPs and Management Area plans exclude aquifers that were exempted 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 KGAGSP and Figure 2-39 of the HMWDGSP 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 with 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 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." 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 groundwater quality in the Project Area than those 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 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 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 and the coordinated water budget indicate that oil and gas industry demand is included in the estimates of urban water use (KCGSAs 2020). The WDWA Management Area Plan states that "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 acre-feet per quarter and 641 acre-feet 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 groundwater than considered in the 2015 FEIR.

In contrast with water demand, the new information provides substantial evidence that oil and gas activities could support sustainable groundwater management in the Project Area to a greater extent than considered in 2015 FEIR. As discussed in Section 4.3, above, 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 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 to -489,828 in the climate change 2070 scenario during 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 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 do not include produced water in the aquifers subject to SGMA. The Annual Report refers to produced water used for domestic or irrigation purposes as a local surface water imported supply (KCGSAs 2020). As a result, projects that expand the availability of produced water for domestic or irrigation use increase the net water supply subject to 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 oilfield produced water to develop new supplies estimated at 1,000 AFY in the AEWSD Management Area Plan.
- Potential development of 7,000 to 20,000 AFY of new produced water supplies in the Cawelo 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 oilfield 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 10-20 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 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 the 2041–2070 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 in the KCS over the 50-year SGMA planning and implementation horizon.

As discussed in the 2015 FEIR, 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 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 acre-feet of produced water per quarter for domestic use (CalGEM 2020). 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 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.

It is important to note that the SGMA Projects 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 Cawelo GSA Management Area Plan, and the WDWA Management Area Plan. As discussed in Section 4.6, 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 as considered in 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 a peer-reviewed study published in May 2020 by researchers from Duke University and RTI International (Duke University 2020). Although 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 8,774 to 11,761 AFY represents the potential impact to groundwater attributable to the Project. Due to the lack of surplus water available in the Project Area, which is also demonstrated by the increasingly negative changes in the annual amount of stored groundwater projected for 2021–2070 without the SGMA Projects in the coordinated water budget, oil and gas consumption of domestic and irrigation quality water would have a significant impact and would contribute to a significant cumulative impact to sustainable groundwater management 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 can be accomplished successfully 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 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. 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 3.3, above, the County withdrew from the KGA in 2018 and does not participate in SGMA management of the Project Area. The GSAs in the Project Area have exclusive jurisdiction for sustainable groundwater management under the SGMA. The GSPs and Management Area plans adopted by the GSAs and prepared by professional geologists and engineers in accordance with SGMA regulations include SGMA Projects that could increase produced water reuse in the KCS. The feasibility of these SGMA Projects is being evaluated in the context of the SGMA in the Project Area. 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 Project's significant impacts to sustainable groundwater management.

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. 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 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 fresh water as a base fluid for fracture treatments would increase the chemical volumes needed to fulfill these functions. Use of produced water 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 (HF acid), which can only be mixed with fresh water. If HF 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. 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.

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 Cawelo 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 County does not have sufficient produced water treatment and distribution facilities to produce 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.

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. 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, while several of the GSPs and Management Area plans consider SGMA Projects that would expand produced water reuse, no new produced water treatment or distribution facilities 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.

Based on these considerations, there are no feasible mitigation measures that would reduce the Project's significant 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 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, the demand for domestic and irrigation quality water for oil and gas activities is projected to increase from 8,778 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.

5.2 Will the project conflict with or obstruct implementation of a water quality control plan or sustainable groundwater management plan?

As discussed in the NOP, potential Project impacts to a water quality control plan were addressed in 2015 FEIR (Kern County Planning and Natural Resources Department 2020). The analysis of these impacts were not identified as a CEQA violation by the Appellate Court.

Potential Project impacts related to conflicts with a sustainable groundwater management plan are substantially similar to the discussion of potential impacts to sustainable groundwater management in Section 5.1, above. GSPs have been adopted for the Tule subbasin, the Tulare Lake subbasin, and the Cuyama Valley basin that primarily address groundwater basins 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 that would significantly conflict with these GSPs. GSPs are not required and have not been adopted for the small portions of the Carizzo Plain basin in the southeast or for the Kettleman Plain basin in the northeast portions of the Project Area. The White Wolf subbasin was separated from the southern portion of the KCS in a basin boundary modification approved by the DWR in 2016. A GSP for the White Wolf subbasin is not required until January 31, 2022, and none has been adopted. The is no substantial evidence that the Project would conflict with a sustainable groundwater management plan in any of these basins or subbasins.

Five GSPs, and 15 Management Area plans within the KGAGSP, 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 the 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 a sustainable groundwater management plan. The GSPs and Management Area plans specifically exclude locations where producible hydrocarbons occur and exempt aquifers under the UIC program from the lateral and vertical boundaries of the groundwater subbasin in the KCS. The KGAGSP, 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 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 2020). 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 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 by 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 (WSWD 2020). 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 oilfield. 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 2019b). There is no substantial evidence that oil and gas activities would cause significant new or significantly greater impacts to sustainable groundwater management plans in the Project Area than considered in the 2015 FEIR.

The GSPs and Management Area plans exclude exempted aquifers from the sustainable groundwater management plans 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 and Figure 2-39 of the HMWDGSP 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 the 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 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.” 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 sustainable groundwater management plans in the Project Area than considered in the 2015 FEIR.

Oil and gas related subsidence is not identified as a significant factor affecting sustainable groundwater management plans 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 CalGEM and subject to state regulation 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 sustainable groundwater management 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 SGMA, provide quantified water demand estimates and projections for urban uses based on per capita water use data, and agricultural demand based on evapotranspiration and crop information in the Project Area. 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 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 specifically 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 acre-feet per quarter and 641 acre-feet 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 sustainable groundwater management plans than considered in the 2015 FEIR.

In contrast with water demand, new information provides substantial evidence that oil and gas activities could support sustainable groundwater management plans in the Project Area to a greater extent than considered in 2015 FEIR. As discussed in Section 4.3, above, 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 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 2041–2070 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.

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 (KCSGSAs 2020). 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 and include the following:

- Reclamation of oilfield produced water to develop new supplies estimated at 1,000 AFY in the AEWSD Management Area Plan;
- Potential development of 7,000 to 20,000 AFY of new produced water supplies in the Cawelo 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 oilfield produced water for agricultural use in the EWMA Plan; and
- 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 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 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 support the implementation of sustainable groundwater management plans in the Project Area.

As discussed in the 2015 FEIR, 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 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 acre-feet of produced water per quarter for domestic use (CalGEM 2020). 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 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 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 sustainable groundwater management plans, and no mitigation measures would be required.

It should be noted that the SGMA Projects are proposed approaches for avoiding undesirable results in conjunction with long-term sustainable groundwater management plans that, by their terms, 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 Cawelo GSA Management Area Plan, and the WDWA Management Area Plan. As discussed in Section 4.6, above, 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 due to regulatory or economic factors.

There is also substantial evidence of ongoing opposition to treated produced water reuse based on perceived health and safety concerns, as discussed in a peer-reviewed study published in May 2020 by researchers from Duke University and RTI International (Duke University 2020). Although 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 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 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 8,774 to 11,761 AFY represents the potential impact to sustainable groundwater plans attributable to the Project. Due to the lack of surplus water available 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 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 sustainable groundwater management 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 can be accomplished successfully 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 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. The Appellate Court determined that these mitigation measures violated CEQA because they did not require or result in predictable reductions in oil and gas domestic and irrigation quality water use, 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 3.3, above, the County withdrew from the KGA in 2018 and does not participate in the SGMA management of the Project Area. The GSAs in the Project Area have exclusive jurisdiction for sustainable groundwater management under the SGMA. The GSPs and Management Area plans adopted by the GSAs and 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 feasibility of these SGMA Projects is being evaluated in the context of the SGMA in the Project Area. 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, moreover, that any such measures 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 additional of produced water reuse and reduce the Project's significant impacts to sustainable groundwater management.

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. 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 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 HF acid, which can only be mixed with fresh water. If HF 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. 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.

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 Cawelo 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 County does not have sufficient produced water treatment and distribution facilities to produce 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.

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. 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, while several of the GSPs and Management Area plans consider SGMA Projects that would expand produced water reuse, no new produced water treatment or distribution facilities 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.

Based on these considerations, there are no feasible mitigation measures that would reduce the Project's significant sustainable groundwater management plan 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 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, the demand for domestic and irrigation quality water for oil and gas activities is projected to increase from 8,778 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 related to conflicts with sustainable groundwater management plans. These impacts would be significant and unavoidable.

5.3 Would the project have insufficient water supplies available to serve the project and reasonably foreseeable future development during normal, dry and multiple dry years?

As discussed in Section 2, above, the 2015 FEIR analyzed potential Project impacts to water supplies by assuming that surface water supplies would vary in accordance with historical data for average, single dry, and multiple dry years, and that groundwater would be available in approximately the average annual extraction amounts over the prior several years in the Project Area. The 2015 FEIR specifically stated that groundwater use would likely vary under future conditions when GSPs were adopted and implemented in the region to meet SGMA requirements and that the estimated groundwater use was not intended to represent the safe yield of regional aquifers. The analysis considered regional supply and demand in average, single dry and multiple dry years over a 20-year period, including estimated oil and gas demand associated with the proposed Project, as well as agricultural demand and urban demand in the Project Area. The demand for domestic and irrigation quality water for oil and gas activities was estimated to be 8,778 AFY in 2012 and would increase to 11,761 AFY with the implementation of the Project. The analysis indicated that domestic and irrigation water supplies were sufficient to meet demand during average years but the margin of supply relative to demand would decrease over time. Significant domestic and irrigation water supply shortfalls would occur in single dry and multiple dry years and would increase to -817,127 AFY in a single dry year to -383,042 AFY during a multiple-year drought.

As discussed in Section 4.1, above, California recently experienced a drought that peaked in July 2014, when 58 percent of the state was determined to be in severe drought conditions. No part of the state has been in a severe drought since 2017. The Annual Report states that, in response to wetter conditions during water years 2016 to 2019, the average annual change in KCS groundwater storage was +177,058 AFY compared with an annual average change of -277,114 AFY from 1995 to 2014 (KCGSAs 2020). California hydrological conditions vary substantially from year to year, including periods of severe rainfall and flooding, and prolonged droughts. In June 2020, the federal drought monitor indicated that water year 2020 was a relatively dry year (NIDIS 2020).

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 Project Area domestic and irrigation quality water supply sources. The GSPs and Management Area plans specifically exclude locations where producible hydrocarbons occur and exempt aquifers under the UIC program from the lateral and vertical boundaries of the groundwater subbasin in the KCS. The KGAGSP, which covers most of the Project Area subject to 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" (KCSGSAs2020). The WKWD 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 of 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 and Figure 2-39 of the HMWDGSP 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 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." 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 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 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 include any 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 acre-feet per quarter and 641 acre-feet 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 production in California. 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 considered in the 2015 FEIR.

In contrast with water demand, the new information provides substantial evidence that oil and gas activities could enhance water supplies in the Project Area to a greater extent than considered in 2015 FEIR. As discussed in Section 4.3, above, 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 to -489,828 in the climate change 2070 scenario during 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 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 and include the following:

- Reclamation of oilfield produced water to develop new supplies estimated at 1,000 AFY in the AEWSD Management Area Plan.
- Potential development of 7,000 to 20,000 AFY of new produced water supplies in the Cawelo 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 oilfield 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 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 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.

As discussed in the 2015 FEIR, 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 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 acre-feet of produced water per quarter for domestic use (CalGEM 2019c). 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 suggests 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.

It should be noted that the 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 AEWSD Management Area Plan, the Cawelo GSA Management Area Plan, and the WDWA Management Area Plan. As discussed in Section 4.6, above, 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 in 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 in a peer-reviewed study published in May 2020 by researchers from Duke University and RTI International (Duke University 2020). Although 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 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 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 8,774 to 11,761 AFY represents the potential impact to sustainable groundwater plans attributable to the Project. Due to the lack of surplus water available 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 can be accomplished successfully 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 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. The Appellate Court determined that these mitigation measures violated CEQA because they did not require or result in predictable reductions in the use of oil and gas domestic and irrigation quality water use, 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 3.3, above, the County withdrew from the KGA in 2018 and does not participate in the SGMA management of the Project Area. The GSAs in the Project Area have exclusive jurisdiction for sustainable groundwater management under SGMA. The GSPs and Management Area plans adopted by the GSAs and prepared by professional geologists and engineers in accordance with SGMA regulations include SGMA Projects that could increase produced water reuse in the KCS. The feasibility of these SGMA Projects is being evaluated in the context of the SGMA in the Project Area. 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 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. 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 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 HF acid, which can only be mixed with fresh water. If HF 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. 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.

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 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 County does not have sufficient produced water treatment and distribution facilities to produce 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 vehicle 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.

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. 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, while several of the GSPs and Management Area plans consider 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 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 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.

Based on these considerations, there are no feasible mitigation measures that would reduce the Project's significant water supply impacts to a 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 Project Area water supplies, 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, the demand for domestic and irrigation quality water for oil and gas activities projected to increase from 8,778 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 regional water supplies. These impacts would be significant and unavoidable.

5.4 Will the project require or result in the relocation or construction of new or expanded water facilities, the construction or relocation of which could cause significant environmental effects?

As discussed in the NOP, the SREIR considers whether new or revised mitigation measures for significant groundwater or water supply impacts would result in the relocation or construction of new or expanded water facilities, the construction or relocation of which could cause significant environmental effects (Kern County Planning and Natural Resources Department 2020). Sections 5.1 to 5.3, above, discuss the Project's impacts to sustainable groundwater management, SGMA plans, and water supplies. The demand for domestic and irrigation quality water for oil and gas activities is projected to increase from 8,778 to 11,761 AFY with Project implementation. 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 considered to be a significant impact and contributes to a cumulatively significant impact to Project Area sustainable groundwater management, SGMA plans, and water supplies. As discussed in Sections 5.1 to 5.3, although several potential mitigation measures to reduce these significant impacts were considered, each was determined to be infeasible in accordance with applicable CEQA criteria. No significant impacts would occur from the relocation or construction of new or expanded water facilities related to the implementation feasible mitigation measures to reduce the Project's impacts on sustainable groundwater management, SGMA plans and water supplies.

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Appendix E

Supplemental Noise Technical Memorandum (October 2020)

MEMO

TO: County of Kern

FROM: Kevin Keller

SUBJECT: Technical Memorandum on Kern SREIR Noise Analysis

DATE: October 15, 2020

Overview

In 2015, Kern County completed the Final Environmental Impact Report for *Proposed Amendments to Title 19- Kern County Zoning Ordinance – Chapter 19.98 for Oil and Gas Local Permitting* (2015 FEIR). As part of the 2015 FEIR, consultants Brown-Buntin & Associates and WJV Acoustics, Inc. conducted various studies of environmental noise and project-related noise levels to assess the Ordinance's impact on the existing noise environment. These studies were included in the 2015 FEIR Appendix V-1, Environmental Noise Assessment and Appendix V-2, Vibration Assessment Report (SREIR Volume 5) and Appendix V-3, Gas Flare Noise Assessment Report (SREIR Volume 7).

Previous Methodology

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 noise levels 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 from wind 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. 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, the SoundPLAN ISO 9613 method is overly conservative and can overpredict 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 regarding noise propagation from individual sources.

This technical memorandum has been prepared to address the assumptions, modeling, and conclusions associated with the assessment and mitigation of the Ordinance's noise impacts.

Noise Studies Regarding Oil and Gas Development Since 2015

At the time of the 2015 FEIR, there were no peer-reviewed studies of noise generated from California oil and gas activities. Although this continues to be the case, recently there have been several studies regarding noise effects from unconventional oil and gas development in other states. The 2015 FEIR indicates that oil and gas development in other states has required extensive use of hydraulic fracturing and horizontal drilling, requiring longer drilling times and resulting in more noise. Studies analyzing the noise generated from these sites are therefore unlikely to be representative of noise generated from oil and gas activities in California. The following studies have been identified:

- **Hays McCawley and Shonkoff (2017**): "**Public Health Implications of Environmental Noise Associated with Unconventional Oil and Gas Development" in *Science of The Total Environment***. 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 and Slagley (2019): "Noise Concerns of Residents Living in Close Proximity to Hydraulic Fracturing Sites in Southwest Pennsylvania."** ***Public Health Nursing***. This study measured noise level in Southwestern Pennsylvania near non-traditional gas industry sites and found levels exceeding the 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 et al. (2017): "A Pilot Study to Assess Residential Noise Exposure Near Natural Gas Compressor Stations."** ***PLoS ONE*****.** 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 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 day-night level (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 sample size of eight homes located within 750 meters of the nearest compressor station evaluated and three homes located within 1000 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 et al. (2017): "Noise Characterization of Oil and Gas Operations."** ***Journal of Occupational and Environmental Hygiene*****.** 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 et al. (2018): "Residential Noise from Nearby Oil and Gas Well Construction and Drilling."** ***Journal of Exposure Science & Environmental Epidemiology***. 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, but no specific distances were provided. 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.

Although the noise studies sited give some interesting observations, none present anything that would dispute the County's EIR.

Metric for Assessment of Noise Impacts

In its General Plan, the County incorporates maximum allowable noise for new land uses: outdoor noise levels are limited to 65 dB DNL and indoor noise levels are limited to 45 dB DNL. DNL (or L_{DN}) refers to the day-night average sound level, which refers to a time-weighted energy average noise level for a 24-hour day, with a 10-dB penalty added to noise levels occurring during the nighttime hours (10:00 p.m. to 7:00 a.m.). The County's exterior and interior noise standards are consistent. 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 a 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.

Because this standard is adopted in the Kern County General Plan, it is appropriate for the County to use the DNL metric to assess noise impacts in its EIR. The use of the noise metric DNL in Kern County's EIR is further supported by the use of similar metrics in federal, state and local noise reports and noise codes. At the federal level, the Federal Interagency Committee on Urban Noise developed land use compatibility guidelines using DNL as the common descriptor for noise levels, which have been incorporated throughout the federal regulatory system. Today, the Federal Transit Authority, Federal Railway Authority, and Federal Aviation Authority all use the metric. At the state level, the California Department of Health Services endorses the use of either DNL or the Community Noise Level (CNEL). Similarly, Government Code section 65302(f) requires local planning documents utilize either DNL or CNEL.

DNL has been endorsed as an appropriate measure 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. The 10-dB penalty applied during the nighttime hour accounts for increased sensitivity to noise exposure occurring during nighttime hours, and therefore addresses the potential for sleep disturbance.

It is not appropriate for the EIR to analyze single event noise. Single event noise is measured by sound exposure level (SEL), is the noise level of a noise event, with the acoustical energy from that noise event, normalized to 1 second. This noise metric is commonly used to describe intermittent or isolated noise events such as an aircraft overflight or train pass-by. It is not appropriate when analyzing long-term exposure for continuous activities such as oil and gas construction and operations. The Federal Transit Authority and Federal Railway Authority use SELs and reference levels for a train pass-by to calculate the LDN noise levels at residential properties. For these kinds of activities, there may be long stretches of quiet with intermittent loud activity. Oil and gas construction and operational noises are not intermittent and therefore the SEL metric is inappropriate. Further, there are no noise standards that utilize the SEL metric on its own.

Mitigation of Project Noise Impacts

Revised Screening Distances

As part of the SREIR, applicant activities will not only be evaluated against the County's adopted 65 dB DNL threshold, but also against an incremental standard. An incremental standard assesses whether the activity will substantially increase the existing ambient noise. For areas less with less than a 60 dB existing ambient, agencies typically use a 5 dB increment. Because the average ambient noise level in the County was determined to be 54.7 dB DNL, it is appropriate for the County to use a 5 dB standard. However, this must work in tandem with the County's 65 dB DNL threshold. To that end, it is appropriate for the County to allow only a 1 dB increase over ambient where the ambient is in excess of 65 dB because such an increase is indiscernible to the human ear.

In the 2015 FEIR, MM 4.12-1 established default setback distances based on the 65 dB DNL contour. In order to ensure that applicants do not exceed the County's incremental threshold, these setback distances should be revised. The option evaluated in this memorandum was to base the default setback distances on the allowable project noise level at the lowest ambient noise level measured in the 2015 Environmental Noise Assessment. This was 44.8 dB. Based on the 5 dB incremental standard, project noise could reach approximately 49 dB L_{eq} (48.8 dB) without resulting in an exceedance. The L_{eq} metric is appropriate for the screening distances in light of the very conservative measurement and modeling methodologies used by the consultants in the 2015 FEIR. The L_{eq} is the equivalent sound pressure level and is commonly used to measure steady-state sound or noise and as such represents the sound as actually experienced by the sensitive receptor. Tables 1 and 2 show how the contours for this level were calculated.

Table 1
Construction Contours to 49 dB L_{eq}

Activity	Distance (feet) to 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

Note:
[(a)] – Kenai Drill Rig #7

Table 2
Operations Contours to 49 dB L_{eq}

Activity	Distance (feet) to Contour
Well Production (Electric Power)	198
Well Production (Diesel Power)	650

These contours remain highly conservative. Typical screening distances for major infrastructure projects are limited to 0.5 miles or 2,600 feet. Additionally, while the screening distances above are calculated using L_{eq} measurements, the noise reduction report and reduction measures described in the 2015 FEIR require the applicant to mitigate based on DNL metrics to ensure nighttime noise and sleep disturbance impacts are mitigated.

Attenuation Measures

There are several measures that can be used to attenuate noise if the operations are inside of the setback distance. 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.

These attenuation measures are compared in Table 3, below.

According to the Federal Highway Administration, noise barriers can achieve a 5 dB noise level reduction when they are tall enough to break the line of sight from the highway to the home or receiver. After breaking the line of sight, barriers can achieve approximately 1.5 dB of additional noise level reduction for each meter of height. However, sound walls are typically limited to 8 meters (25 feet) in height. Depending on the height difference between the noise source and the top of wall, the noise reduction could be between 10 and 15 dB.

Placement of moveable noise barriers around individual pieces of equipment helps reduce the noise source within the project site and reduce the noise level reaching the property line. Depending on the noise levels of the shielded equipment, this could help reduce noise level at the property line by 5 to 7 dB. If these are combined with a property line barrier or berm the overall noise reduction could be between 15 and 20 dB.

Barriers can be formed from earth mounds (or "berms"), from high vertical walls or from a combination of earth berms and walls. Earth berms have a very natural appearance and are usually attractive. They also reduce noise by approximately 3 dB more than vertical walls of the same height. If they can be built, berms on the property blocking the line of sight to the noise sources would provide the same noise level reductions that a sound attention wall would provide. But depending on the height of the berm needed, the amount of land/soil needed to build the berm may prohibit its placement.

Orientation of the drilling equipment and/or use of hospital-grade muffler, like the movable noise barrier, would reduce the noise levels at the source within the project site. Both could reduce the noise levels from the equipment by 5 to 10 dB. Orientation of drilling equipment would work if there are no noise-sensitive receivers on at least two sides of the equipment. Like the movable noise barriers, if orientation of the drilling equipment is combined with the property line sound attention wall, there will be an increase in the overall noise reduction.

Electrification of equipment provides noise reduction based on the equipment replaced. Although the noise level from the engines of electric equipment is lower, the overall operations of the equipment may be same due to other noise sources on the site. Based on contours calculated for the 2015 FEIR, the electrification of production equipment could reduce noise by 8 to 10 dB.

Table 3
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

Flare Noise Setback

In 2015, WJV Acoustics, Inc., prepared an acoustical analysis to specifically analyze the noise impacts from venting and flaring, which were included as Appendix V-3 of the 2015 FEIR (SREIR Volume 7). Noise levels associated with gas flare activities were measured at several locations throughout Kern County (see Table 4).

Table 4
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

WJV Acoustics, Inc. noted that distances described in for the “Shafter Flare” should not be applied to common gas flare operations performed in Kern County. The Shafter Flare was operating under anomalous conditions during the measurement period. Noise setback analysis distances described above for the flares excluding the Shafter Flare represent noise levels that are to be expected from commonly used gas flares throughout the County. Based on the above measurements, the County setback of 210 feet for all new oil and gas wells will ensure that noise from flares operating under typical conditions will not exceed the County's 65 dB DNL standard.

Extrapolating from the 2015 measurements, the new operational screening distances based on the 49 dB L_{eq} contour for diesel-powered operations will also capture the vast majority of noise effects created by gas flares, as shown in Table 5.

Table 5
Gas Flare Noise Exposure

Flare	Distance (feet) to 49 dB L_{eq} Contour	Electric-Powered Production Screening Contour (feet)	Diesel-Powered Production Screening Contour (feet)
Hopkins Flare	48	198	650
Redbank and Edison	141		
Semitropic	205		
Shafter[a]	NA		
Maricopa	394		

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

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Appendix F
Sensitive Receptor Community Analysis
(October 2020)

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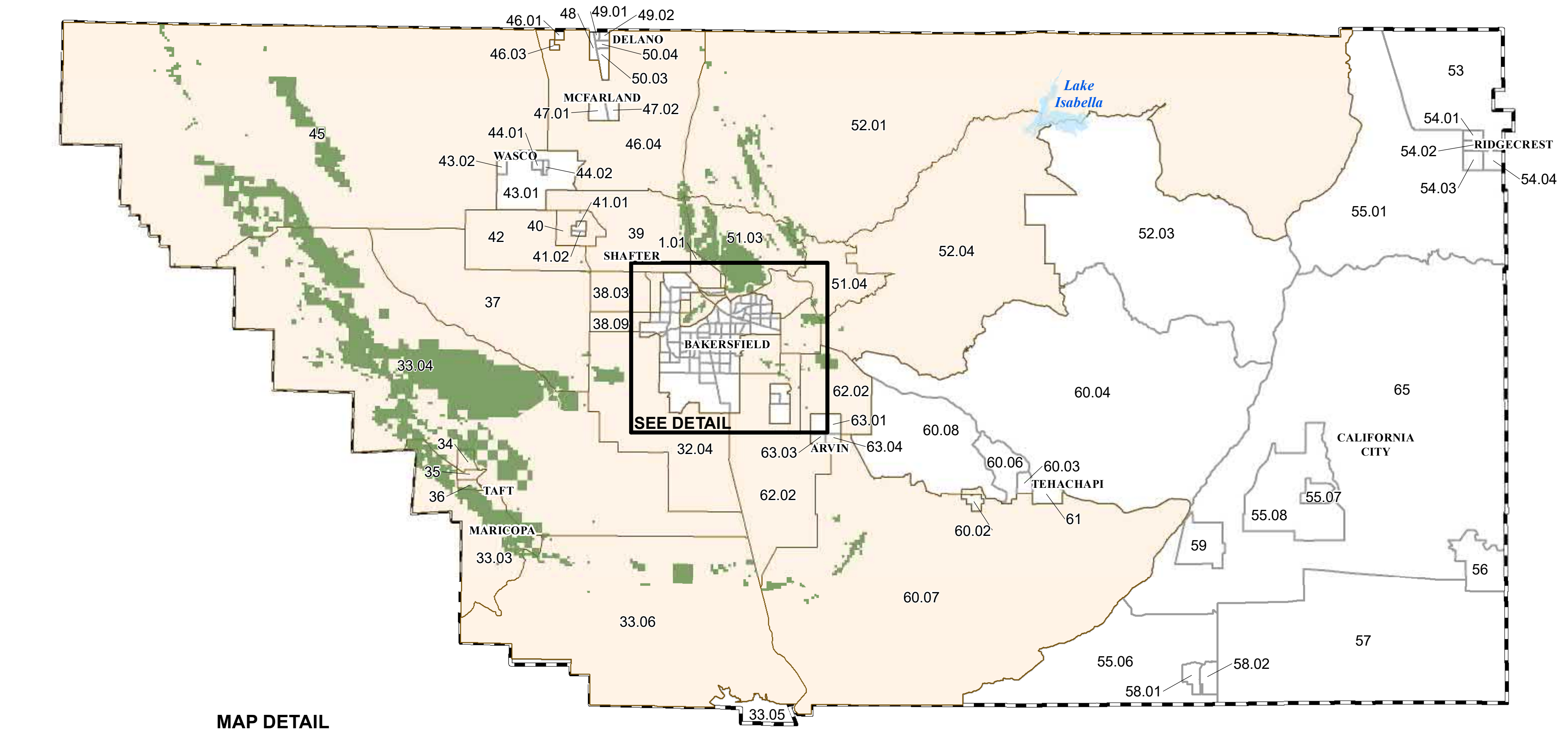
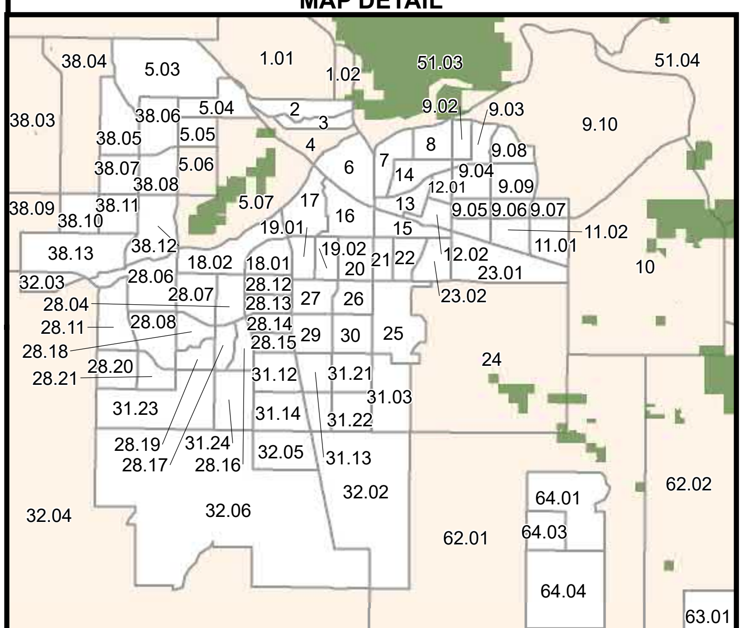


MAP DETAIL



Revisions to Title 19 – Kern County Zoning Ordinance (2020-A)
Focused on Oil and Gas Local Permitting
Census Tracts with Tier I Acreage

- Tier I
- Census Tracts with Tier I Acreage
- Census Tracts with no Tier I Acreage
- Kern County Boundary

Census Tracts with Tier I Acreage:
1.01, 1.02, 4, 5.06, 5.07, 9.10, 10, 24, 32.04, 33.03, 33.04, 33.06, 34, 35, 36, 37, 38.03, 38.04, 38.09, 39, 40, 42, 45, 46.04, 51.03, 51.04, 52.01, 52.04, 60.07, 62.01, 62.02

Source: U.S. Census Bureau, American Community Survey 2014-2018

Map created by the Kern County
Planning and Natural Resources Department

9/2/2020

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Table 1
Kern County Census Tract Overview

	Kern County	**Census Tracts Without Tier 1 Acreage**	**Census Tracts With Tier 1 Acreage**
Number of Census Tracts	151	120	31
Total Census Tract Acreage	5,223,961	1,926,769	3,297,191
Acreage of Tier 1 in Census Tracts	215,208	-	215,208
Percentage of Census Tract Acreage in a Tier I Location	4%	0%	7%

Table 2
Kern County Census Tract Demographics

	Kern County	**Census Tracts Without Tier 1 Acreage**	**Census Tracts With Tier 1 Acreage**
Total population	883,053	685,717	197,336
Percent of Total County Population	100%	78%	22%
Percent Hispanic or Latino (of any race)	52.75%	55.26%	44.05%
Percent White	34.77%	31.50%	46.11%
Percent Black or African American	5.10%	6.05%	1.80%
Percent American Indian and Alaska Native	0.48%	0.44%	0.61%
Percent Asian	4.56%	4.48%	4.85%
Percent Pacific islander, other race, two or more races	2.34%	2.27%	2.57%

Table 3
Kern County Census Tracts, Population in Poverty

	Kern County	**Census Tracts Without Tier 1 Acreage**	**Census Tracts With Tier 1 Acreage**
Population for Which Poverty Level Was Determined	851,826	660,668	191,158
Total Population Below Poverty Level	187,232	153,988	33,244
Percent total population below poverty level	21.98%	23.31%	17.39%

Table 4
Top Ten Tier 1 Census Tracts with Most Tier 1 Acreage
Overview

	Kern County	**Census Tracts Without Tier 1 Acreage**	**Top Ten Tier 1 Census Tracts with Most Tier 1 Acreage**
Number of Census Tracts	151	120	10
Total Census Tract Acreage	5,223,961	1,926,769	2,668,378
Acreage of Tier 1 in Census Tracts	215,208	-	207,129
Percentage of Total Tier I Acreage	100%	0%	96%

Table 5
Top Ten Tier 1 Census Tracts with Most Tier 1 Acreage
Demographics

	Kern County	Census Tracts Without Tier 1 Acreage	Top Ten Tier 1 Census Tracts with Most Tier 1 Acreage
Total population	883,053	685,717	42,943
Percent of Total County Population	100%	78%	4.86%
Percent Hispanic or Latino (of any race)	52.75%	55.26%	34.06%
Percent White	34.77%	31.50%	53.59%
Percent Black or African American	5.10%	6.05%	2.15%
Percent American Indian and Alaska Native	0.48%	0.44%	0.51%
Percent Asian	4.56%	4.48%	7.05%
Percent Pacific islander, other race, two or more races	2.34%	2.27%	2.64%

Table 6
Top Ten Tier 1 Census Tracts with Most Tier 1 Acreage
Population in Poverty

	Kern County	Census Tracts Without Tier 1 Acreage	Top Ten Tier 1 Census Tracts with Most Tier 1 Acreage
Population for Which Poverty Level Was Determined	851,826	660,668	40,242
Total Population Below Poverty Level	187,232	153,988	5,969
Percent Total Population Below Poverty Level	21.98%	23.31%	14.83%

Table 7
Top Ten Tier 1 Census Tracts with Largest Population
Overview

	Kern County	Census Tracts Without Tier 1 Acreage	Top Ten Tier 1 Census Tracts with Largest Population
Number of Census Tracts	151	120	10
Total Census Tract Acreage	5,223,961	1,926,769	376,453
Acreage of Tier 1 in Census Tracts	215,208	-	7,318
Percentage of Total Tier I Acreage	100%	0%	3%

Table 8
Top Ten Tier 1 Census Tracts with Largest Population
Demographics

	Kern County	Census Tracts Without Tier 1 Acreage	Top Ten Tier 1 Census Tracts with Largest Population
Total population	883,053	685,717	114,297
Percent of Total County Population	100%	77.65%	12.94%
Percent Hispanic or Latino (of any race)	52.75%	55.26%	52.48%
Percent White	34.77%	31.50%	35.33%
Percent Black or African American	5.10%	6.05%	2.35%
Percent American Indian and Alaska Native	0.48%	0.44%	0.61%
Percent Asian	4.56%	4.48%	6.80%
Percent Pacific islander, other race, two or more races	2.34%	2.27%	2.42%

Table 9
Top Ten Tier 1 Census Tracts with Largest Population
Population in Poverty

	Kern County	**Census Tracts Without Tier 1 Acreage**	**Top Ten Tier 1 Census Tracts with Largest Population**
Population for Which Poverty Level Was Determined	851,826	660,668	92,005
Total Population Below Poverty Level	187,232	153,988	19,204
Percent Total Population Below Poverty Level	21.98%	23.31%	20.87%

Table 10
Top Ten Tier 1 Census Tracts with Largest Percentage Tier 1 Coverage
Overview

	Kern County	**Census Tracts Without Tier 1 Acreage**	**Top Ten Tier 1 Census Tracts with Largest Percentage Tier 1 Coverage**
Number of Census Tracts	151	120	10
Total Census Tract Acreage	5,223,961	1,926,769	1,117,042
Acreage of Tier 1 in Census Tracts	215,208	-	184,857
Percentage of Total Tier I Acreage	100%	0%	86%

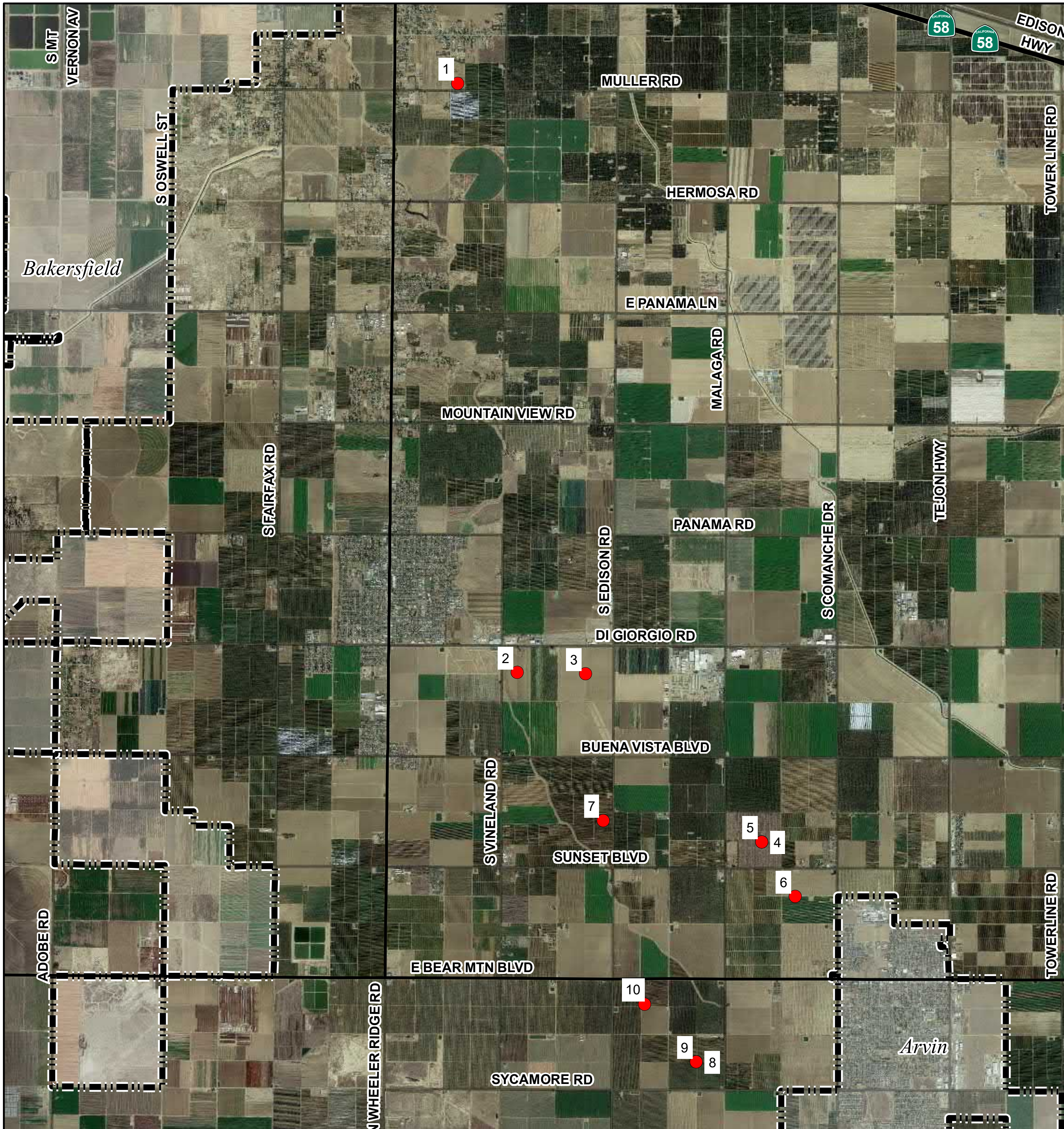
Table 11
Top Ten Tier 1 Census Tracts with Largest Percentage Tier 1 Coverage
Demographics

	Kern County	**Census Tracts Without Tier 1 Acreage**	**Top Ten Tier 1 Census Tracts with Largest Percentage Tier 1 Coverage**
Total population	883,053	685,717	54,495
Percent of Total County Population	100%	77.65%	6.17%
Percent Hispanic or Latino (of any race)	52.75%	55.26%	50.79%
Percent White	34.77%	31.50%	44.12%
Percent Black or African American	5.10%	6.05%	0.92%
Percent American Indian and Alaska Native	0.48%	0.44%	0.59%
Percent Asian	4.56%	4.48%	1.40%

Table 12
Top Ten Tier 1 Census Tracts with Largest Percentage Tier 1 Coverage
Population in Poverty

	Kern County	**Census Tracts Without Tier 1 Acreage**	**Top Ten Tier 1 Census Tracts with Largest Percentage Tier 1 Coverage**
Population for Which Poverty Level Was Determined	851,826	660,668	52,930
Total Population Below Poverty Level	187,232	153,988	11,982
Percent Total Population Below Poverty Level	21.98%	23.31%	22.64%

Kern County Oil and Gas Parcels with Sensitive Receptors



- Oil and Gas Permits with Sensitive Receptors
- Highways/Roads
- City Limits

1. PLN19-01211, 177-181-195
2. PLN18-00054, 189-030-570
3. PLN18-00148, 189-030-174
4. PLN17-01674, 189-150-113
5. PLN17-00815, 189-150-113
6. PLN17-01622, 189-240-625
7. PLN18-01132, 189-200-02
8. PLN19-01493, 189-290-075
9. PLN18-00494, 189-290-075
10. PLN18-01757, 189-290-380

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9/21/2020

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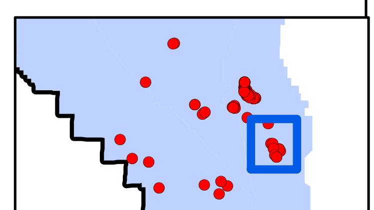
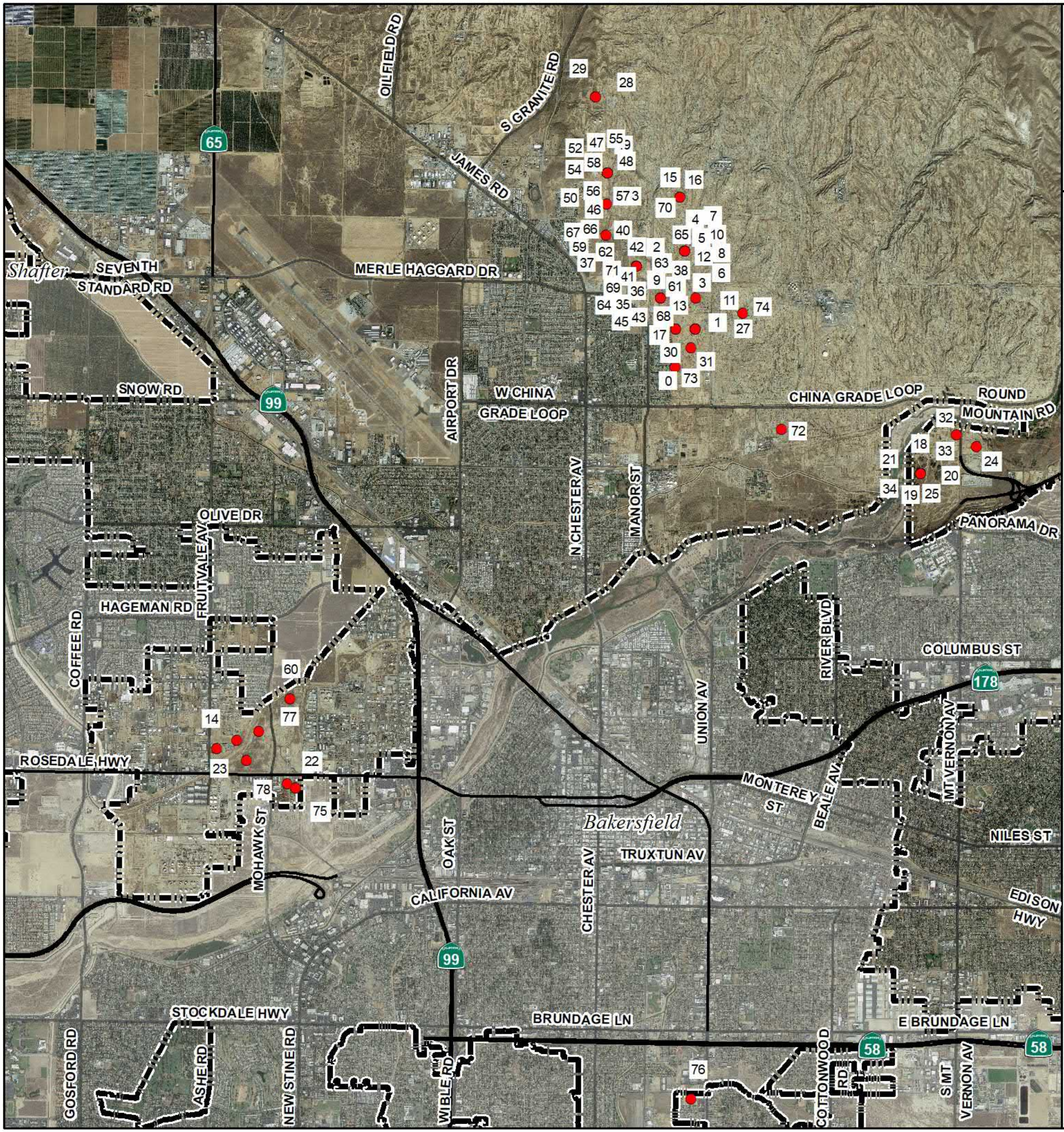




Kern County Oil and Gas Parcels with Sensitive Receptors

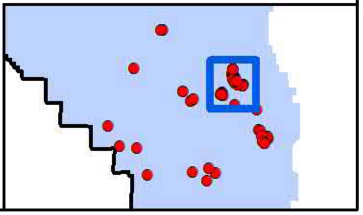
● Oil and Gas Permits with Sensitive Receptors

Highways/Roads

City Limits

ID#	Permit	APN	ID#	Permit	APN
0	PLN16-00264	117-020-099	41	PLN18-02360	484-020-235
1	PLN16-01206	117-012-054	42	PLN18-02361	484-020-235
2	PLN17-00125	093-210-375	43	PLN18-02362	484-020-235
3	PLN17-00126	093-210-375	44	PLN18-02363	484-020-235
4	PLN17-00127	093-210-375	45	PLN18-02370	484-020-235
5	PLN17-00128	093-210-375	46	PLN18-02372	484-010-020
6	PLN17-00290	093-210-375	47	PLN19-01134	484-010-020
7	PLN17-00292	093-210-375	48	PLN19-01135	484-010-020
8	PLN17-00294	093-210-375	49	PLN19-01136	484-010-020
9	PLN17-00514	093-210-375	50	PLN19-01142	484-010-020
10	PLN17-00516	093-210-375	51	PLN19-01143	484-010-020
11	PLN17-01384	117-012-047	52	PLN19-01144	484-010-020
12	PLN17-01387	093-210-375	53	PLN19-01145	484-010-020
13	PLN17-01464	117-012-062	54	PLN19-01147	484-010-020
14	PLN17-02007	332-020-890	55	PLN19-01148	484-010-020
15	PLN18-00114	093-410-108	56	PLN19-01149	484-010-020
16	PLN18-00115	093-410-108	57	PLN19-01150	484-010-020
17	PLN18-00504	117-012-062	58	PLN19-01151	484-010-020
18	PLN18-00586	436-053-011	59	PLN19-01175	484-010-038
19	PLN18-00590	436-053-011	60	PLN19-01233	332-012-376
20	PLN18-00596	436-053-011	61	PLN19-01234	484-020-235
21	PLN18-00604	436-053-011	62	PLN19-01235	484-020-235
22	PLN18-00647	332-270-024	63	PLN19-01350	484-020-235
23	PLN18-00665	332-030-204	64	PLN19-01351	484-020-235
24	PLN18-00859	436-051-130	65	PLN19-01352	484-020-235
25	PLN18-01049	436-053-011	66	PLN19-01353	484-020-235
26	PLN18-01184	117-012-054	67	PLN19-01354	484-020-136
27	PLN18-01224	117-012-054	68	PLN19-01355	484-020-235
28	PLN18-01321	481-110-104	69	PLN19-01356	484-020-235
29	PLN18-01322	481-110-104	70	PLN19-01357	484-020-235
30	PLN18-01327	117-012-054	71	PLN19-01358	484-020-235
31	PLN18-01361	117-012-054	72	PLN19-01394	436-041-099
32	PLN18-01528	436-053-037	73	PLN19-01548	117-020-032
33	PLN18-01534	436-053-011	74	PLN19-02211	436-030-01
34	PLN18-01535	436-053-011	75	PLN20-00469	332-270-016
35	PLN18-02214	117-012-013	76	PLN20-00546	011-300-035
36	PLN18-02215	117-012-013	77	PLN20-00887	332-020-866
37	PLN18-02356	484-020-235	78	PLN20-00888	332-020-817
38	PLN18-02357	484-020-235			
39	PLN18-02358	484-020-235			
40	PLN18-02359	484-020-235			

0 0.5 1 2 Miles



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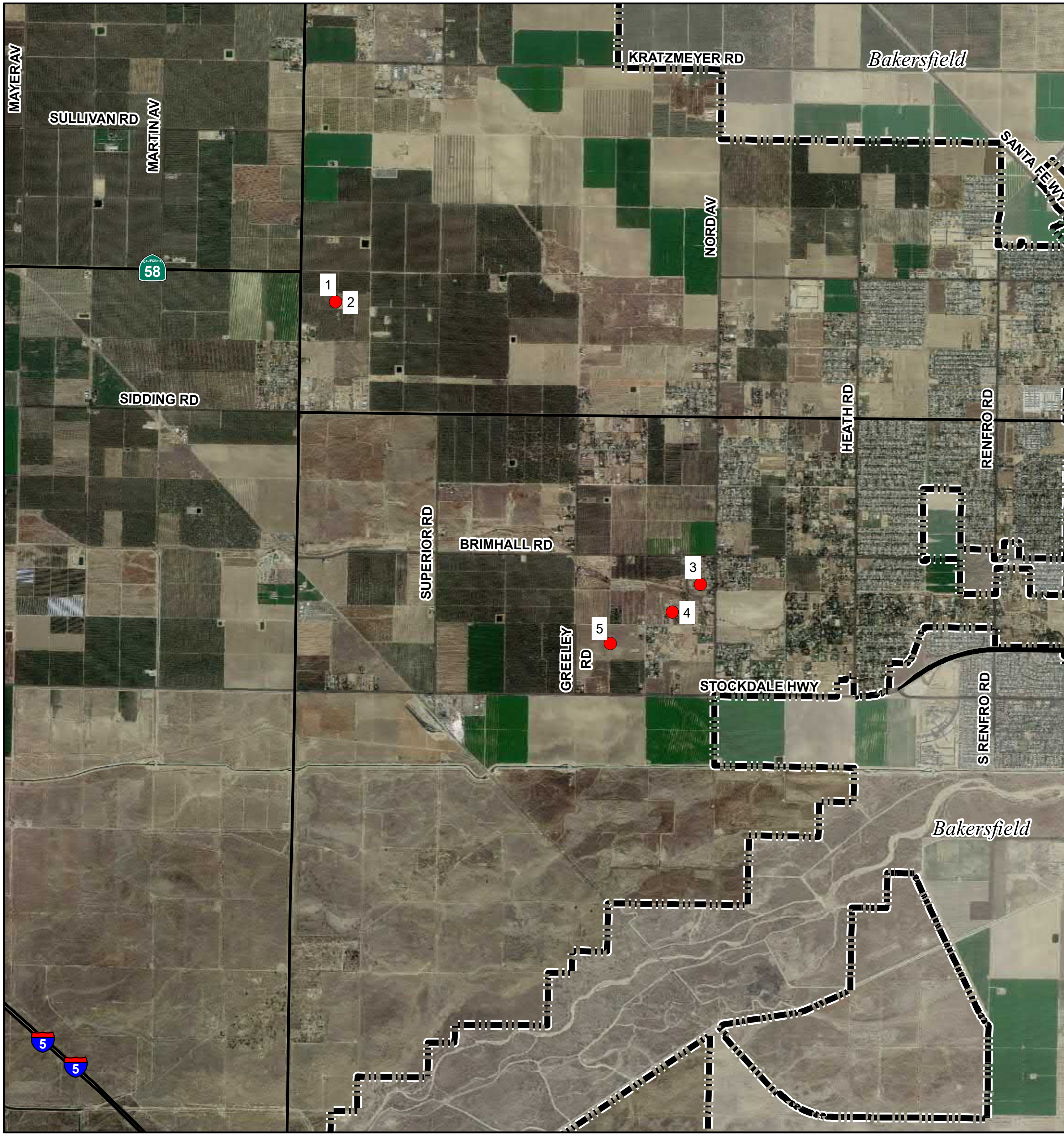
Kern County Oil and Gas Parcels with Sensitive Receptors



● Oil and Gas Permits with Sensitive Receptors

Highways/Roads

City Limits

1. PLN18-01541, 104-230-024
2. PLN18-01542, 104-230-024
3. PLN19-00669, 408-130-425
4. PLN18-00634, 408-122-570
5. PLN18-01181, 408-250-017

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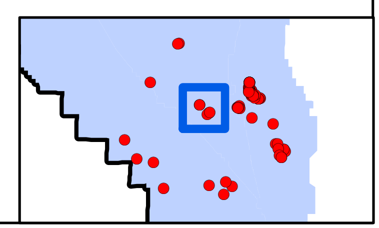
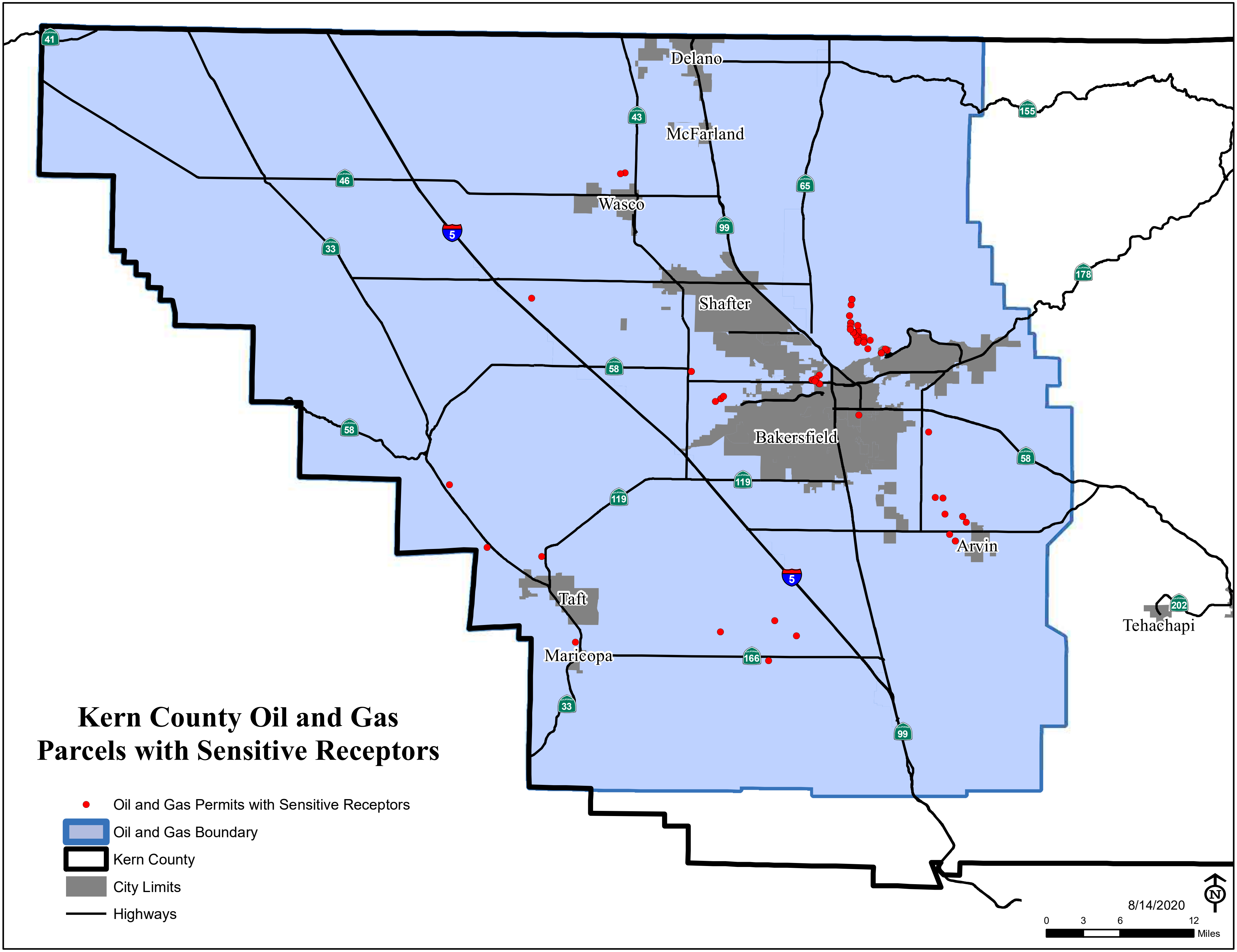
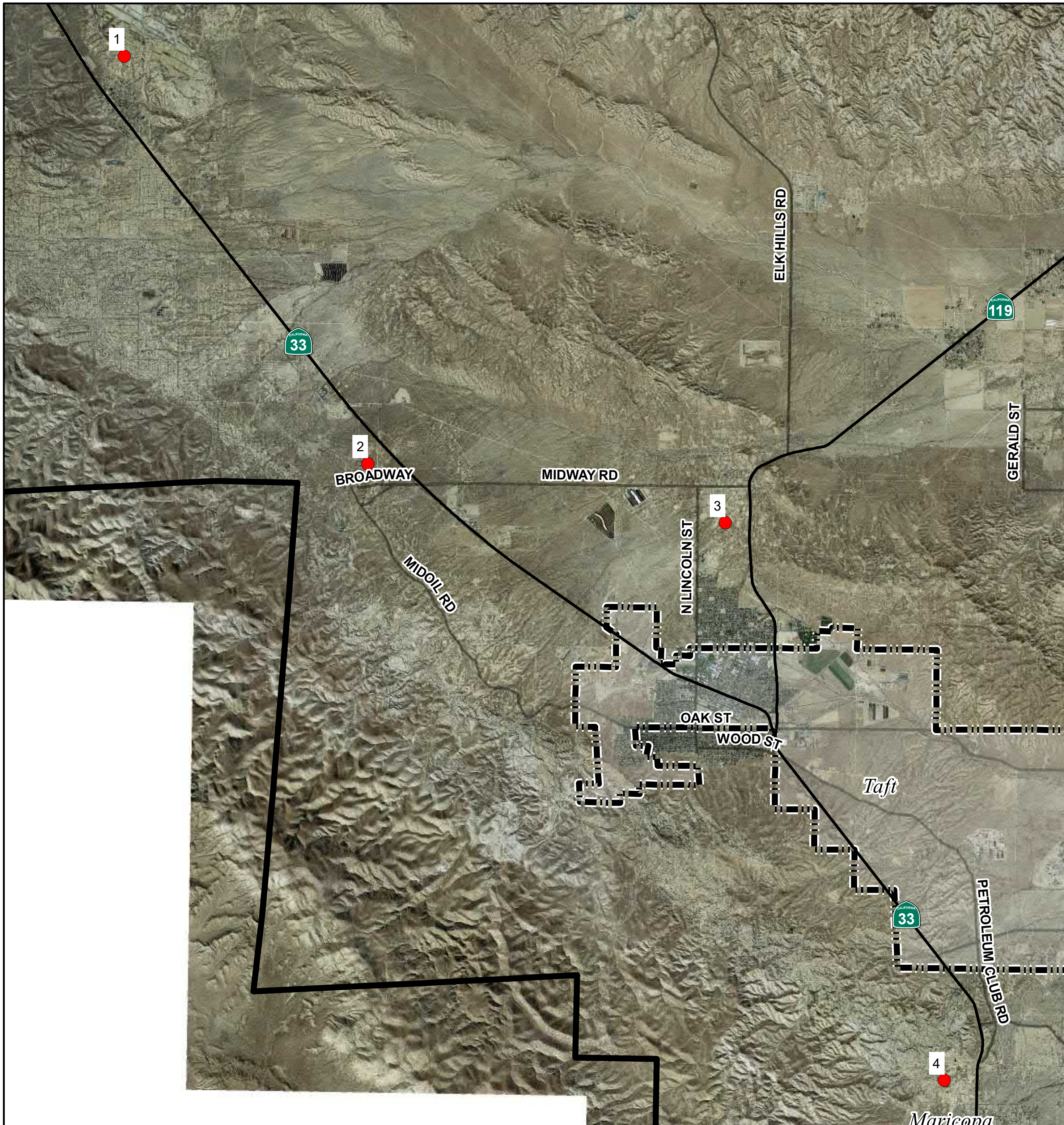


9/24/2020

Kern County Oil and Gas Parcels with Sensitive Receptors



Kern County Oil and Gas Parcels with Sensitive Receptors

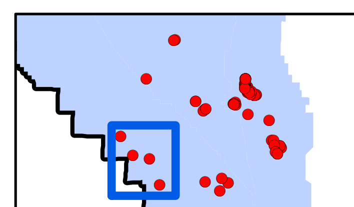


- Oil and Gas Permits with Sensitive Receptors
- Kern County
- Highways/Roads
- City Limits

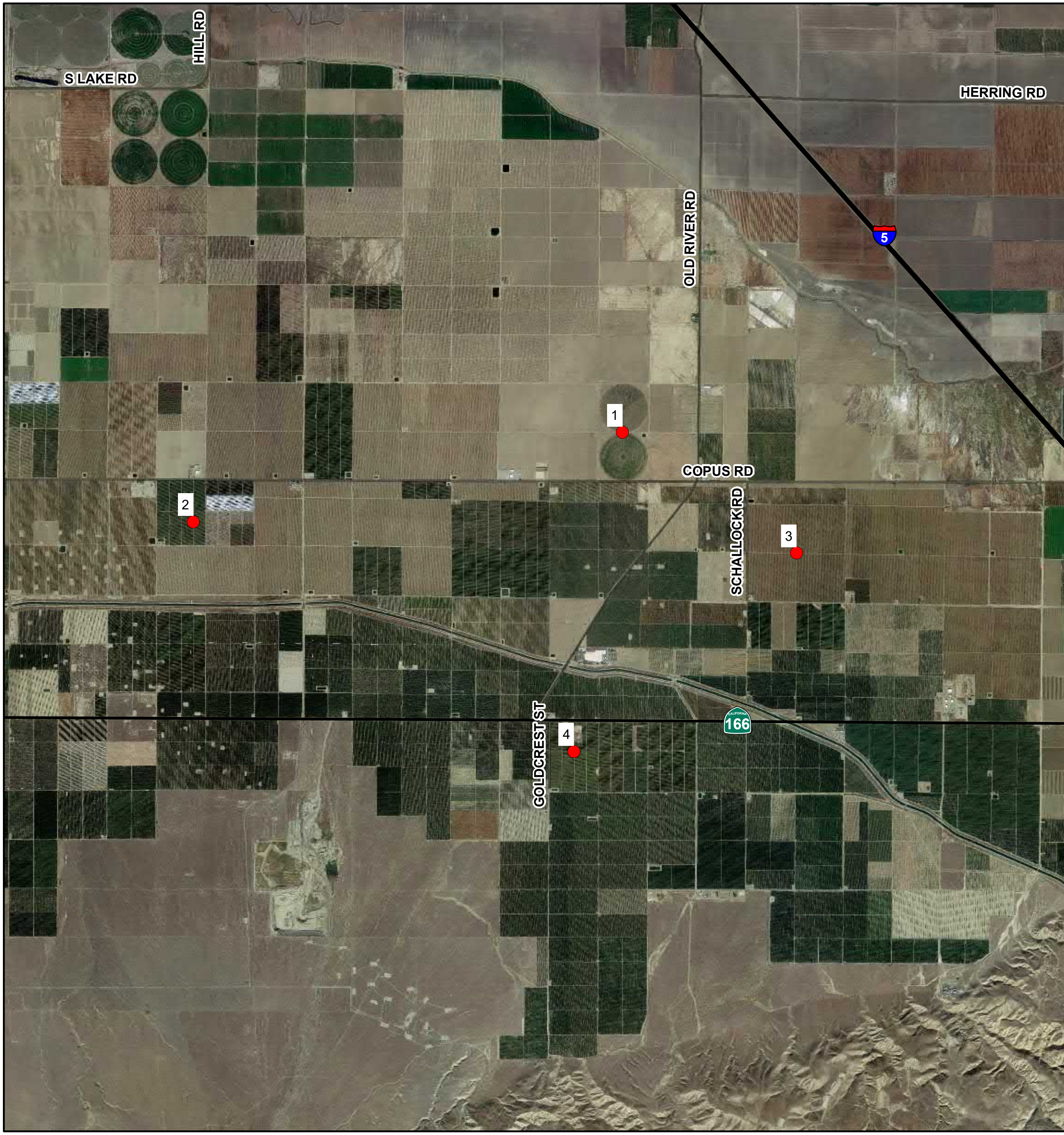
1. PLN20-00239, 183-010-339
2. PLN17-02170, 298-060-278
3. PLN18-02245, 198-010-209
4. PLN20-00610, 239-280-142

0 0.75 1.5 3 Miles

9/24/2020



Kern County Oil and Gas Parcels with Sensitive Receptors



Oil and Gas Permits with Sensitive Receptors

Highways/Roads

City Limits

1. PLN19-01892, 295-130-785
2. PLN17-01424, 295-170-19
3. PLN18-01235, 295-210-025
4. PLN19-02579, 239-022-056

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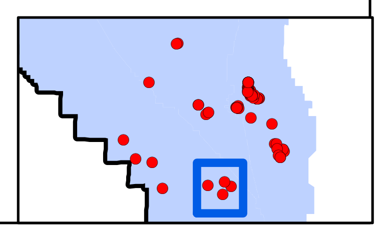

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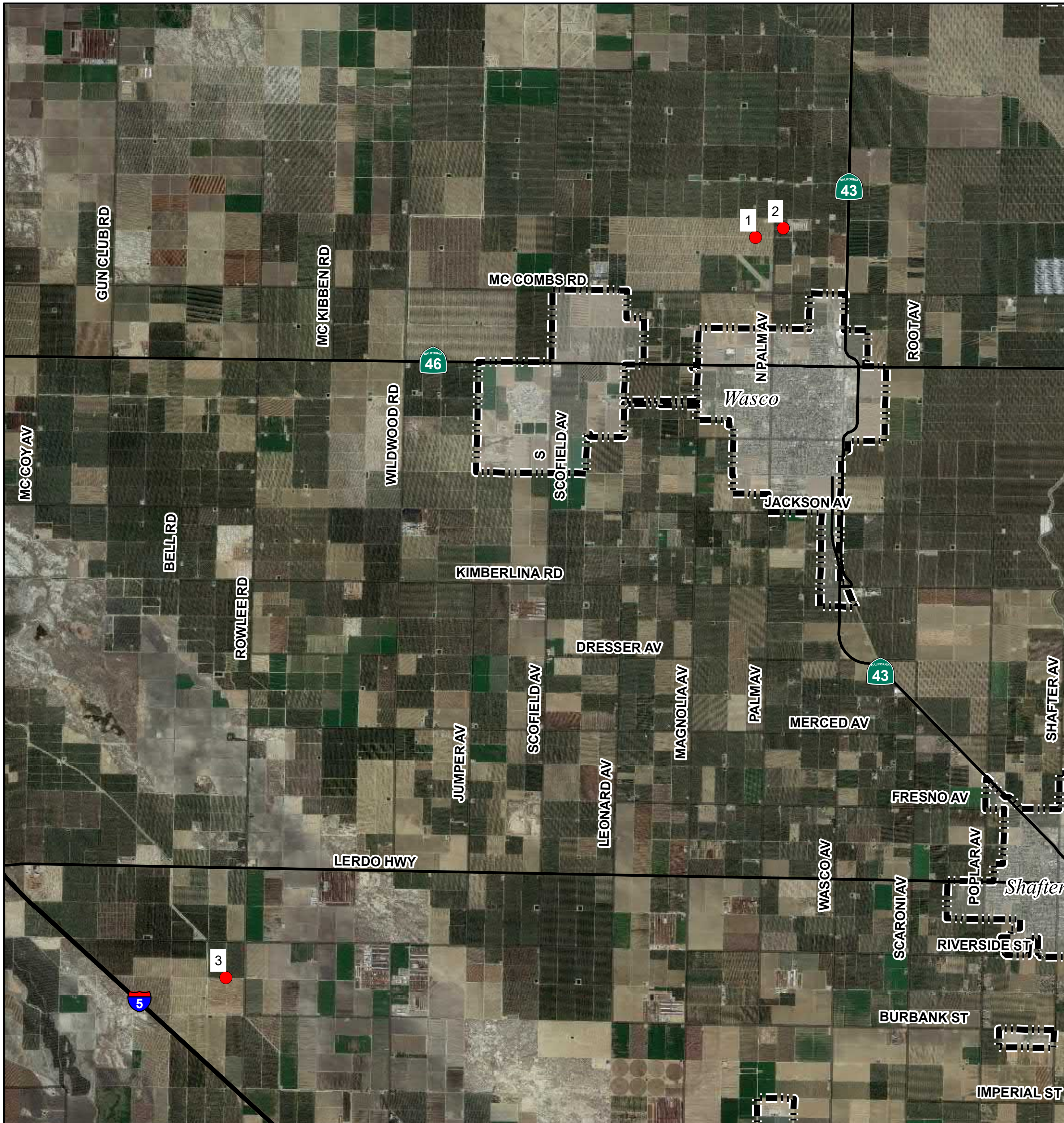
Kern County Oil and Gas Parcels with Sensitive Receptors



Oil and Gas Permits with Sensitive Receptors

Highways/Roads

City Limits

1. PLN19-00919, 059-280-222
2. PLN17-00510, 059-280-040
3. PLN17-00701, 087-130-308

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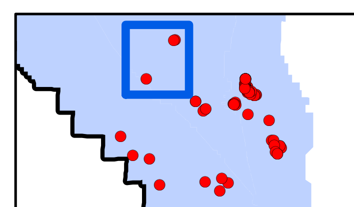

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