Appendix B. Central Coast Field Office Area – Reasonably Foreseeable Development Scenario for Oil and Gas

This section describes the Reasonably Foreseeable Development Scenario (RFD Scenario) for oil and gas in the Central Coast Field Office[1] (CCFO) area. It estimates the level and type of future oil and gas activity in the planning area for analysis of the Resource Management Plan (RMP) Amendment and provides a basis for the analysis of cumulative effects. For this RFD Scenario, "reasonably foreseeable" is defined as projected to occur based on development trends in the CCFO area in recent years and is based on a reasonable, technical, and scientific estimate of anticipated oil and gas activity based on the best available information and data at the time of the study (Instruction Memorandum (IM) No. 2004-089 "Policy for Reasonable Foreseeable Development (RFD) Scenario for Oil and Gas," dated January 16, 2004). Reasonably foreseeable does not include scenarios that are merely speculative or only have a remote possibility of occurring. This RFD Scenario has been updated[2] from the Bureau of Land Management's (BLM's) Hollister Field Office RFD Scenario for Oil and Gas, which was included as Appendix F in the Record of Decision for the RMP for the Southern Diablo Mountain Range and Central Coast of California, to include new information based on oil and gas drilling technologies, including well stimulation, and recent oil and gas development trends in California. Based on current regulations and the range of projected activity on federal mineral estate within the planning area, this RFD Scenario is applicable regardless of which of the alternatives analyzed in the EIS is chosen as the Preferred Alternative.

The RFD Scenario first describes the steps involved in exploring for and developing deposits of oil and gas. Trends and assumptions affecting oil and gas activity are discussed, along with estimates for future oil and gas exploration and development. The RFD Scenario is based on known or inferred oil and gas occurrence potential from California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR) records, independent assessments of scientific literature, and knowledge of local experts with experience in the leasing and development of federal minerals (Milliken, 1990; USGS, 1915). The lands included are limited to those with BLM-administered minerals, including split estate with private surface estate and federal sub-surface minerals.

It should be noted that not all mineral estate managed by the BLM may have been identified at this time. For purposes of this document, all mineral estate managed by the BLM is considered covered by this RFD Scenario, even if BLM maps do not currently show the mineral estate. Mineral estate on lands that may be acquired in the future will also be covered by this RFD Scenario, so long as the values and resources that are contained on the newly acquired lands do not differ significantly from those on existing known federal mineral estate.

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[1] The Hollister Field Office (HFO) transitioned to a new location in Marina, California, in February 2016, and was renamed as the BLM Central Coast Field Office (CCFO). This RFD Scenario was completed in October 2015; it includes edits to reflect the current name of the area and other administrative clarifications.

[2] This update was prompted by a court order and settlement agreement. The court in *Center for Biological Diversity v. Bureau of Land Management* found it unreasonable for BLM to "consider only a single exploratory well scenario solely based on past data" based on the record in the case. 937 F. Supp. 2d 1140, 1156 (N.D. Cal. 2013).

1. Past and Present Oil and Gas Exploration and Development

This section describes oil and gas exploration and development on BLM-administered surface and split-estate lands, as well as provides a detailed description of past and current activities throughout the entire CCFO area.

The CCFO area covers over 6.8 million acres, within which there are 792,430 acres of federal mineral estate (11.6 percent of the total area). As of mid-2014, there are 65 authorized oil and gas leases on federal mineral estate within the CCFO covering an estimated 41,184 acres. Eighty (80) active producing and service oil and gas wells and 66 idle wells are located on federal mineral estate within the CCFO. Over 99 percent of the wells in the CCFO area are located within oil and gas field boundaries, with less than 1 percent being classified as wildcats (outside administrative field boundaries). Of the total 4,292 producing wells within the CCFO area, the 146 wells that occur on federal authorized leases amount to BLM involvement with 3.4 percent of all current oil and gas activity within the CCFO boundary. In the two years prior to October 2015, two Applications for Permit to Drill (APD) on existing BLM leases in the Coalinga area were submitted to the BLM; these are the first APDs submitted to the CCFO in the 20 years prior to 2015. However, by July 2018, one of the APDs was canceled and the other was in suspension.

Table 1. Hollister Field Office Planning Area, Oil and Gas Data (as of mid-2014)

	BLM CCFO-Administered Public Lands	CCFO Planning Area, Total
Oil and gas leases on federal mineral estate	65 leases	—
Leased land area of federal mineral estate	~41,200 acres	—
Area of existing oil and gas fields	—	204,200 acres
Area of active oil and gas fields	~28,200 acres of federal mineral estate	195,330 acres
Wells	80 active producing and service wells & 66 idle wells	4,292 wells (active) (3.4% on BLM federal mineral estate)
Federal mineral estate area	**~792,430 acres federal mineral estate** (includes ~231,050 acres of BLM-administered surface and ~561,380 acres of split estate)	**~6,820,400 acres** (11.6% is Federal mineral estate)

Since the 2007 Proposed RMP and EIS, the BLM and the State of California have sponsored independent third-party extensive statewide studies of the geology of oil and gas basins and industry activities, including well stimulation treatments, such as hydraulic fracturing, acid matrix stimulation and acid fracturing. These studies improve the understanding of past and present exploration and development in the CCFO area. The California Council on Science and Technology (CCST) released its Independent Scientific Assessment (ISA) on Advanced Well Stimulation Technologies in California, commissioned by the BLM, in August 2014 (CCST, 2014). In January 2015, the CCST released Volume I of the State's ISA of Well Stimulation in California, which was required by Senate Bill (SB) 4. Volume I focuses on geology and well stimulation treatments and their past, present, and potential future use in California (CCST, 2015).

The CCST Volumes II and III were released in July 2015. Volume II (Generic and Potential Environmental Impacts of Well Stimulation Treatments) assesses the potential impacts of well stimulation treatments with respect to water, air quality, and greenhouse gas emissions, as well as induced seismicity, ecology, traffic, and noise. Volume III (Case Studies with Selected Evaluations of Environmental and Public Health Risk) presents case studies assessing environmental issues and qualitative hazards for specific geographic regions, based on findings in Volumes I and II.

Figure 1 (Major Sedimentary Basins and Faults in California) shows the location of the Hollister Field Office area with respect to the major sedimentary basins in California. Specifically, Figure 2 (Major Formations in BLM Central Coast Field Office Administrative Area) illustrates that the CCFO area provides access to petroleum resources in the following sedimentary basins that occur near or within the CCFO area (from north to south):

- Sacramento Basin, in Contra Costa County.
- San Joaquin Basin, in San Joaquin, Stanislaus, and Fresno Counties.
- Sargent-Hollister Basin, in Santa Clara and San Benito Counties.
- Salinas Basin, in San Benito and Monterey Counties.
- Cuyama Basin, south of the CCFO area.
- Santa Maria Basin, south of the CCFO area.

Recent well drilling activity is not evenly distributed across California and largely occurs outside of the CCFO area. The CCST surveyed recent activity to determine the numbers of wells with first production or injection since 2002. The CCST surveys also identified the wells with records of past hydraulic fracturing. The vast majority of California statewide activity occurs in Kern County and in other portions of the San Joaquin Basin, only a small portion of which is within the eastern portion of the CCFO area (CCST, 2015, Appendix J, p. 349).

Of the 12 counties in the CCFO planning area, six have had some recent levels of well activity, including Alameda, Contra Costa, Fresno, Monterey, San Benito, and Santa Clara Counties. However, existing wells are located on BLM-administered land only in the following counties: Contra Costa, Fresno, Monterey, San Benito, and Santa Cruz. No wells are located on BLM-administered land in Alameda, Merced, San Francisco, San Joaquin, San Mateo, Santa Clara, or Stanislaus Counties. In general, most of the well activity in the counties covered by CCFO occurs in Fresno County and in Monterey County (see Table 2, CCFO Planning Area Oil and Gas Activity by County, and Table 3, Fields in CCFO Planning Area with Record of Hydraulic Fracturing).

Recent oil and gas activity in the CCFO area has involved only limited levels of well stimulation by hydraulic fracturing. In the Fresno County portion of the CCFO area, which has the highest level of well stimulation, 4 percent of recently-producing wells indicate any record of previous hydraulic fracturing.

Table 2. CCFO Planning Area Oil and Gas Activity by County (as of mid-2014)

County	Active, Producing Wells and Service Wells	Idle Wells	Buried or Plugged Wells	Wells with First Production or Injection (2002-2013)(1)	Wells with Record of Hydraulic Fracturing (2002-2013)(2)	Portion of Wells with Record of Hydraulic Fracturing (2002-2013)
Alameda	7	5	77	1	—	—
Contra Costa	55	10	598	13	1	7.7%
Fresno	3,163	1,407	5,552	1,214	42	3.5%
Merced	—	—	8	—	—	—
Monterey	1,005	663	1,893	679	3	<1%
San Benito*	27	23	336	2	—	—
San Joaquin	—	1	18	—	—	—
San Mateo	16	24	155	—	—	—
Santa Clara	19	1	89	7	—	—
Santa Cruz	—	—	59	—	—	—

Table 2. CCFO Planning Area Oil and Gas Activity by County (as of mid-2014)

County	Active, Producing Wells and Service Wells	Idle Wells	Buried or Plugged Wells	Wells with First Production or Injection (2002-2013)(1)	Wells with Record of Hydraulic Fracturing (2002-2013)(2)	Portion of Wells with Record of Hydraulic Fracturing (2002-2013)
Stanislaus	—	—	24	—	—	—
Total	**4,292**	**2,134**	**8,809**	**1,916**	**46**	**2.5%**

Source: DOGGR GIS (2014) appended by Appendix M, CCST, 2015; (1): Appendix L, CCST, 2015; (2): Appendix L; one of the wells with a record of hydraulic fracturing in Monterey County was a wildcat well that has been subsequently abandoned (CCST, 2015).

* In November 2014, San Benito County passed a ban on hydraulic fracturing and related gas and oil extraction activities, as well as other "high-intensity petroleum operations" including acid well stimulation and cyclic steam injection within the County. A lawsuit against San Benito County to overturn the ban was filed with the County's Superior Court by Citadel Exploration on February 27, 2015, but was dropped April 3, 2015.

Table 3. Fields in CCFO Planning Area with Record of Hydraulic Fracturing (as of mid-2014)

Field	County	Active, Producing Wells and Service Wells	Wells with First Production or Injection (2002-2013)(1)	Wells with Record of Hydraulic Fracturing (2002-2013)(2)	Portion of Wells with Record of Hydraulic Fracturing (2002-2013)
Dutch Slough Gas	Contra Costa	18	7	1	14.3%
Coalinga	Fresno	2,934	1,081	41	3.8%
Lynch Canyon	Monterey	38	31	none found	none found
Monroe Swell	Monterey	14	5	2	40%
San Ardo	Monterey	918	571	none found	none found

Source: DOGGR GIS (2014) appended by Appendix M, CCST, 2015; (1): Appendix L, CCST, 2015; (2): Appendix L based on searching all records in Contra Costa and Fresno and 55% of records in Lynch Canyon, 80% of records in Monroe Swell, and 20% of records in San Ardo. Note that only 2 records of hydraulic fracturing were found in Monterey County, in Monroe Swell after searching 21.5% of well records county-wide (Appendix J, CCST, 2015).

In the CCFO area, past and present oil and gas activity occurs across 35 active oil and gas fields, with a total administrative area of 195,300 acres. Twelve of the 35 active fields intersect federal mineral estate. The most-productive fields in the area (in order of cumulative past production) are:

- Coalinga Oil and Gas Field with Coalinga East Extension Oil and Gas Field;
- San Ardo Oil and Gas Field;
- Lynch Canyon Oil and Gas Field;
- Jacalitos Oil and Gas Field;
- Kettleman North Dome Oil and Gas Field; and
- Hollister-Sargent Oil and Gas Field.

Nearly all well development since 2002 occurred in the Coalinga, San Ardo, Lynch Canyon, and Jacalitos fields. For each of these oil and gas fields and other less-productive fields, the recent activity and numbers of wells with first production or injection since 2002 are shown for these major fields in Table 4 (Well Development Activity in Major Oil and Gas Fields Within the CCFO Planning Area). Other fields in the CCFO area had little to no record of new activity found by the CCST ISA. Within the listed fields, the CCST survey identified over 1,700 wells with first production or injection since 2002 (CCST, 2015, Appendix L, Well-Record Result Data Set).

Table 4. Well Development Activity in Major Oil and Gas Fields Within the CCFO Planning Area

Field	County	2002-2006 Wells Drilled	2007-2011 Wells Drilled	2012-2013 Wells Drilled	2002-2013 Well Total
Coalinga	Fresno	385	595	101	1,081
Coalinga East Ext	Fresno	2	0	0	2
San Ardo	Monterey	121	370	80	571
Lynch Canyon	Monterey	3	25	3	31
Jacalitos	Fresno	23	23	6	52
Major Fields in CCFO, Subtotal		**534**	**1,013**	**190**	**1,737**
All Fields in CCFO, Total		**551**	**1,043**	**191**	**1,785**
Annual Average Rate in CCFO		**110 per year**	**209 per year**	**~110 per year**	**~150 per year**
California, Total		**14,865**	**15,520**	**6,543**	**36,928**

Source: DOGGR GIS (2014) appended by Appendix L, CCST, 2015. The 2013 year includes first nine months.

1.1 Monterey Formation

The Monterey Formation, a thick Miocene age sequence of marine sediments consisting of siliceous, phosphatic, organic, and clay-rich shales and mudstones, dolomites, and intercalated turbiditic sandstones, is a dominant traditional and potential future oil and gas resource currently being developed in California. The Monterey Formation is complex, both stratigraphically and structurally, given the active tectonic environment in which it was deposited.

In 2011, the U.S. Energy Information Administration (EIA) published a report projecting that deeper portions of the Monterey Formation "source" rock that has not yet been economically produced could contain large oil resources, estimating 15.4 billion barrels of technically recoverable oil, which, at the time, represented 64 percent of the entire estimated "tight oil" resources in the lower contiguous United States.[3] In 2012, the EIA revised its technically recoverable reserves estimate for the Monterey Formation from 15.4 to 13.7 billion barrels.

Then in December 2013, J. David Hughes, a Canadian geoscientist, published a paper stating that the EIA's 2011 production forecasts for the Monterey Formation were overly optimistic due to: (1) its geologic complexity and (2) the fact that it cannot be approached using the same types of technology that has been, and is currently applied, to other shale resources outside California, such as the Marcellus, the Bakken and the Eagle Ford shale plays[4] (DOC, 2015, p. 6-17).

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3 The U.S. EIA's 15.4 billion barrel estimate of the Monterey Formation's potential was cited in the United States District Court, Northern District of California's 2013 Order Re Cross Motions for Summary Judgment (*Center for Biological Diversity and Sierra Club v. The Bureau of Land Management,* Case No. C 11-06174 PSG), which has resulted in the preparation of this Hollister Oil and Gas RMP Amendment/EIS. However, this estimate has since been revised by the U.S. EIA and the CCST ISAs have determined that the source rock production potential of the Monterey Formation is uncertain.

4 A "play" is a conceptual model for a style of hydrocarbon accumulation used by explorationists to develop prospects in a basin, region or trend and used by development personnel to continue to evaluate a given trend. A play (or a group of interrelated plays) generally occurs in a single petroleum system. In geology, a petroleum play, or simply a play, is a group of oil and gas fields or prospects in the same region that are controlled by the same set of geological circumstances. The geographic limit of each play represents the limits of the geologic elements that define the play. (DOC, 2015, p. 6-6)

Subsequently, in May 2014, the U.S. EIA announced that its 2011 projection for the estimated amount of recoverable oil from the Monterey Formation has been reduced by as much as 96 percent, meaning that the formation may only be capable of producing an estimated 600 million barrels of oil with existing technology in comparison to the initially estimated 15.4 billion barrels of oil[5] (CCST, 2014, p. 169). Neither estimate is well constrained. There is little published information on the deep sedimentary sections of the Monterey Formation, so it is difficult to estimate the potential recoverable reserves associated with these rocks. No reports of significant production of source oil from these rocks were identified in the CCST ISA, and recent exploration wells that have targeted deeper portions of the Monterey Formation, where active source rocks could potentially retain unmigrated oil, have not resulted in the identification of new oil reserves to date (CCST, 2014, pp. 122 and 169).

The original area of the play was 7500 square miles, of which approximately 46 square miles was located in the CCFO boundary (0.6%). The leased area inside the overall play was 1752 square miles (CCST, 2014, p. 166); 6.5 square miles were BLM leases within the 46 square miles inside the CCFO boundary. There is currently a single unleased federal parcel of 56 acres (less than 0.2% of the Monterey play as currently mapped) in the CCFO boundary. The remaining approximately 39 square miles of the play within the CCFO boundary are non-federal minerals.

As previously mentioned, the new “area with potential” is 192 square miles (CCST, 2014, p. 166), approximately 3% of the original play size, which corresponds with the 96% reduction in unproven reserves. There is no published data within the CCFO area describing where the current “area with potential” is located. There is no record of even a single well in the CCFO boundary which has targeted the Monterey Shale source rock. Federal mineral estate represents only 14% of the original play acreage within the CCFO boundary (approximately 4,000 federal acres out of 29,000 total acres). Consequently, based on currently available data, there is only a small chance that the current Monterey play will be successfully developed in CCFO.

If the production of potential oil and gas resources in the Monterey Formation occurs in the future, it is likely that a combination of techniques would be used on vertical or horizontal wells along with increased precision due to improving modeling and reservoir characterization methods. These techniques could include acid matrix stimulation (with and without horizontal drilling), thermal recovery by steam-flooding and cyclic steam-injection, and waterflooding, in addition to some usage of hydraulic fracturing in single or multiple stages (DOC, 2015, p. 6-19).

The key to production from deeper portions of the Monterey Formation will be continued improvements in scientific and engineering understanding of the formation, both as a source rock and reservoir (DOC, 2015, p. 6-19). As such, the potential to discover significant oil resources from new plays in the deep source rocks of the Monterey Formation is highly uncertain (CCST, 2014, p. 122). Section 2.5 (Future Oil and Gas Development) discusses the oil and gas development potential of the Monterey Formation within the CCFO area.

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[5] At the May 21, 2014 Oil & Gas Strategies Summit in New York, EIA Administrator Adam Sieminski announced that the federal agency had drastically cut its estimates of technically recoverable oil in the Monterey Shale from 13.7 billion barrels to 600 million barrels. According to Sieminski’s reported comments, the revision was prompted, in part, by new evidence the EIA and U.S. Geological Survey collected on output from wells where new techniques have been tested.

2. Oil and Gas Occurrence Potential

California

The Great Valley of California, composed of the San Joaquin and Sacramento Basins, is a forearc basin that has a thick sequence of marine and non-marine rocks which range in age from Late Jurassic to Holocene. The Great Valley is highly productive of gas in the north and of oil in the south (BLM, 2015).

The California coastal basins are located south and west of the Great Valley. They are small but typically contain very thick Neogene sedimentary rock fill. Several of these basins have been exceedingly rich in discovered petroleum, particularly the Los Angeles, Ventura, and Santa Maria Basins, which are not within the CCFO area. Principal producing zones are in Miocene and Pliocene reservoir rocks, primarily sandstone units and fractured siliceous rocks (BLM, 2015).

The United States Geological Survey (USGS) has identified six Oil and Gas Provinces which partially occur within the Hollister Field Office and are shown on Figure 3 (Oil and Gas Provinces within the Hollister Field Office) (BLM, 2015):

- Province 7: North Coastal;
- Province 8: Sonoma-Livermore;
- Province 9: Sacramento Basin;
- Province 10: San Joaquin Basin;
- Province 11: Central Coastal; and
- Province 12: Santa Maria.

Provinces 9 and 10 embrace the Sacramento and San Joaquin Basins, respectively. Provinces 7, 8, 11 and 12 are within the California coastal basins.

Within these Oil and Gas Provinces, the CCFO has areas of high, moderate, low and no occurrence potential (see Figure 4), which are each described in this section along with a discussion of future oil and gas development in Section 2.5 (Future Oil and Gas Development). The size of each category is shown in Table 5 (CCFO Oil and Gas Occurrence Potential).

Table 5. CCFO Oil and Gas Occurrence Potential

Category	Total Acres within CCFO Planning Area	Federal Mineral Estate
High	1,853,670 acres	451,680 acres
Moderate	611,660 acres	2,680 acres
Low	2,274,610 acres	79,470 acres
None	2,080,430 acres	258,600 acres
Total	6,820,400 acres	792,430 acres

Source: BLM, 2015. CCST, 2015, p. 253.

These areas of oil and gas occurrence potential have been updated from the 2007 Hollister Field Office RFD Scenario for Oil and Gas (BLM, 2007). An explanation of the modifications from the 2007 RFD Scenario is included in Section 2.3 (Comparison of Oil and Gas Occurrence and Development Potential with 2007 Hollister Field Office RFD Scenario). The updates are based on information from BLM geologists and from the CCST ISAs (BLM, 2015; CCST, 2014; CCST, 2015).

As summarized by CCST, Table 6 (Resource Volume and Unconventional Resource Potential in the CCFO Area, by Basin) categorizes the known petroleum volume, undeveloped conventional resource potential, and potential for unconventional continuous resources with prospective application of well stimulation treatments for basins in the CCFO area (CCST, 2015, p.253).

Table 6. Resource Volume and Unconventional Resource Potential in the CCFO Area, by Basin

Basin	Known Petroleum Volume (cumulative and reserves)	Undiscovered/Undeveloped Conventional Potential	Continuous Unconventional Resource Potential
Bitterwater	Minor	Low	Low
La Honda	Minor	Moderate	Low
Pescadero	None	Low	Low
Sargent-Hollister	Minor	Low	Low
Sacramento Gas	Very Large	Moderate	Low
Salinas	Large	Moderate	Possible
San Joaquin	Very Large	Large	Possible

Known Petroleum Volume: Minor = Producing fields; Large = one giant field (>100MMBOE); Very Large = Multiple giant fields.
Undiscovered/Undeveloped Resource Potential: Low =< 50MMBOE; Moderate = 50-500MMBOE; Large => 500MMBOE.
Continuous Unconventional Resource Potential: Possible = Geology and location may permit development with existing technology and economics; Low = Not currently feasible.
Source: Table 4-6 of CCST, 2015, p. 253.

The conventional and unconventional resource information developed by CCST and summarized in Table 6 has been used to focus the areas of oil and gas occurrence potential shown in Figure 4 and discussed in Sections 2.1 through 2.3, as follows:

- The CCST information confirms that only the San Joaquin and Salinas Basins provide "possible" levels of unconventional resource potential, and these are areas of "moderate" to "very large" petroleum volume and oil and gas potential in Table 6. This confirms that the future potential for these two basins would be high.
- The high resource potential in the La Honda and Sacramento Gas basins is only partially confirmed by the CCST information that shows a "moderate" conventional resource potential and "low" unconventional resource potential. This suggests that the future potential would be moderate in these two basins.
- The high resource potential in the Bitterwater, Pescadero, and Sargent-Hollister Plays is not confirmed by the CCST information that shows "minor" known petroleum volumes and a "low" conventional and unconventional resource potential. This suggests that the future potential would be low in these three plays.
- Areas falling outside of an identified petroleum play documented in the CCST ISAs should be viewed as having a low future occurrence potential.

2.1 High Oil and Gas Occurrence Potential

Areas of high oil and gas occurrence potential are depicted on Figure 4 (Oil and Gas Occurrence Potential) within the CCFO area. The areas of high oil and gas potential within each USGS Oil and Gas Province are described below.

High oil and gas occurrence potential[6] is defined in BLM Planning for Fluid Mineral Resources Handbook H-1624-1 as an area having inclusion in an oil and gas play as defined by the USGS national assessment, or, in the absence of a play designation by USGS, the demonstrated existence of: source rock(s), thermal maturation, and reservoir strata possessing permeability and/or porosity, and traps. Demonstrated existence is defined by physical evidence or documentation in the literature (BLM, 1990).

Although much of the area in the CCFO boundary is classified as high potential for occurrence, this does not imply that these areas have been or ever will be developed. In fact, throughout the state (and country), much — or even most — of the area classified as high potential for occurrence will likely never see development. However, it is quite likely that the vast majority of future development will be in areas classified as high potential for occurrence. This is primarily because an area classified as low or no potential has no geologic evidence of one or more of the four geologic factors required to be classified as high potential, and all four factors must be present to have the possibility of an economic accumulation.

Great Valley Oil and Gas Basins

Province 10 (San Joaquin Basin). As illustrated in Figure 4, the Province 10 area of high oil and gas occurrence potential is located in southeastern San Benito County and western Fresno County. This area is part of the San Joaquin Basin and has 8 oil fields that produce from Miocene and Pliocene marine sedimentary rocks. The Coalinga Field, located in western Fresno County, is the most productive field in the CCFO area and is currently the eighth largest oil and gas field in California. The entire San Joaquin Basin in the CCFO area is underlain by the following oil and gas plays, except for a 9- by 4-mile strip in the far northwest corner of the basin, just west of Westley (BLM, 2015):

- *Eocene Composite.* The area underlies all of the CCFO that is within the San Joaquin Basin, except for a 9- by 4-mile strip in the far northwest corner of the basin, just west of Westley.
- *Winters-Domengine/Assessment Unit 100101: Northern Nonassociated Gas.* The area lies in the north-central part of the San Joaquin Valley north of the City of Fresno. Within the CCFO this represents a strip that extends no more than 4 miles west of the eastern CCFO boundary.
- *Miocene*. The area is situated in the northernmost Kettleman Hills and a portion of Kettleman Plain. It encompasses about 43,500 acres within the CCFO.
- *Mature Source Rock.* The area underlain by this play is situated in Kettleman Plain. Within CCFO it is about 2,400 acres.

As shown in Table 6 (Resource Volume and Unconventional Resource Potential in the CCFO Area, by Basin), the CCST ISA confirms that the San Joaquin Basin provides “large” conventional oil and gas potential, “possible” levels of unconventional resource potential, and has a “very large” known petroleum volume (CCST, 2015, p. 253).

Coastal Oil and Gas Basins

Province 11 (Central Coastal). This area of high oil and gas occurrence potential in Province 11 is located in southwestern San Benito County and southeastern Monterey County. Within the CCFO, the Central

[6] Potential refers to potential for the presence (occurrence) of a concentration of one or more energy and/or mineral resources. It does <u>not</u> refer to, or imply, the potential for <u>development</u> and/or <u>extraction</u> of the mineral resource(s). It does not imply that the potential concentration is or may be <u>economic</u>, that is, that it could be extracted profitably at the present time. (BLM, 1985).

Coastal Province includes two confirmed plays, the Salinas and the La Honda Oil Plays, as well as two hypothetical plays, the Pescadero and the Bitterwater Oil Plays. These basins and plays are all within the Central Coastal Neogene Play. The Central Coastal Neogene play is characterized by hydrocarbon accumulations in structural, stratigraphic, and combination traps in sandstone reservoirs mainly of Miocene age.

However, as shown in Table 6 (Resource Volume and Unconventional Resource Potential in the CCFO Area, by Basin), the CCST ISA confirms that only the Salinas Basin Play within Province 11 provides “moderate” conventional oil and gas potential, “possible” levels of unconventional resource potential, and has a “large” known petroleum volume, which corresponds to high occurrence potential in this RFD Scenario (CCST, 2015, p. 253). The other three plays within Province 11 are discussed under Moderate and Low to No Oil and Gas Occurrence Potential below.

- *Salinas Basin.* The play includes known and hypothetical accumulations of hydrocarbons (mainly oil and associated gas) in gently to moderately deformed Tertiary rocks more than 19,000 feet thick. The Salinas Oil Play includes one giant oil field, San Ardo (about 530-860 million barrels of oil [MMBO]); the much smaller King City field (about 2.1-3.3 MMBO); and five other fields (smaller than 1 MMBO). Average producing reservoir depths are generally 2,500 feet or less.

2.2 Moderate Oil and Gas Occurrence Potential

As defined in BLM Planning for Fluid Mineral Resources Handbook H-1624-1, moderate or medium oil and gas occurrence potential areas are where there are geophysical or geological indications that the following may be present: source rock, thermal maturation, and reservoir strata possessing permeability and/or porosity and traps. Geologic indication is defined by geological inference based on indirect evidence (BLM, 1990).

Great Valley Oil and Gas Basins

Province 9 (Sacramento Basin). There are two total petroleum systems (plays) in the CCFO area within the Sacramento Basin, which are separated by a regional shale layer. The *Dobbins-Forbs Play* lies below the shale and the *Winters-Domengine Play* is above. Nearly two-thirds of the estimated undiscovered natural gas resources is expected in the Winters-Domengine play. However, this area has been classified as moderate based on the CCST ISA (see also Table 6, Resource Volume and Unconventional Resource Potential in the CCFO Area, by Basin), which shows a “moderate” conventional resource potential and “low” unconventional resource potential for the Sacramento Basin (CCST, 2015, p. 253).

Within the CCFO area of moderate oil and gas potential in Province 9, there are 12 productive oil and gas fields and three abandoned fields.

Coastal Oil and Gas Basins

Province 11 (Central Coastal). Within the northwestern area of the CCFO, the Central Coastal Province includes the *La Honda Oil Play*. Four oil fields have been developed within this play. In 1983, there were estimated reserves of 1.7 million barrel of oil equivalent (MMBOE).

Although there is an identified play, this area has been classified as moderate based on the CCST ISA (see also Table 6, Resource Volume and Unconventional Resource Potential in the CCFO Area, by Basin), which has classified the play as having a “moderate” conventional resource potential, a “low” unconventional resource potential, and a “minor” known petroleum volume (CCST, 2015, p. 253).

2.3 Low or No Oil and Gas Occurrence Potential

BLM Planning for Fluid Mineral Resources Handbook H-1624-1 defines low oil and gas occurrence potential as areas with specific indications that one or more of the following may not be present: source rock, thermal maturation, or reservoir strata possessing permeability and/or porosity, and traps. Areas of no oil and gas occurrence potential have a demonstrated absence of (1) source rock, (2) thermal maturation, or (3) reservoir rock that precludes the occurrence of oil and/or gas. Demonstrated absence is defined by physical evidence or documentation in the literature (BLM, 1990).

Therefore, in order to assess oil and gas potential you must be in possession of information pertaining to source rock, thermal maturation, reservoir strata possessing permeability and/or porosity, and traps. Since the USGS has assessed oil and gas plays within the CCFO, it stands to reason that every place it did not identify as a play must be lacking one or more of these characteristics. Therefore, areas with potentially favorable rock type, but lacking other critical criterial have been mapped as having low potential.

Within the CCFO area, the areas of low or no oil and gas occurrence potential are areas that are underlain dominantly by granitic, volcanic, metamorphic, and ophiolite sequence rocks, as well as rocks of the Franciscan Formation. These areas of low or no oil and gas occurrence potential are shown on Figure 4 and are described below for each USGS Oil and Gas Province. Province 9 (Sacramento Basin) does not have any areas of low or no oil and gas occurrence potential.

Coastal Oil and Gas Basins

Province 7 (North Coastal)

Province 7 is bounded on the west by the San Andreas Fault and within the CCFO area on the east by the Hayward, Tesla and Ortigalita faults.

- *Sargent-Hollister Oil & Gas Basin* (play) is located in the southern Santa Clara Valley, about 80 miles southeast of the City and County of San Francisco. This play encompasses the Sargent and Hollister oil and gas fields. The CCST ISA (see also Table 6) shows "minor" known petroleum volumes and a "low" conventional and unconventional resource potential. Although there are active oil and gas fields with active wells within the Sargent-Hollister Play, the levels of production in these fields are minor and the CCST data suggests that the future potential would be low (CCST, 2015, p. 253).
- *South of Sargent-Hollister Play* – Low.
- *Santa Clara Valley Play (hypothetical).* Preliminary calculations suggest that about 1 billion barrels of oil may have been generated from petroleum-source rocks within the Monterey Formation in the deepest part of the subsurface sedimentary basin between Los Gatos and Cupertino (BLM, 2015). However, this hypothetical play falls outside of an identified petroleum play documented in the CCST ISAs, and thus, has been viewed as having a low future potential (CCST, 2015, p. 253).
- *San Francisco Bay/Santa Clara Valley* – Low.
- *Diablo Range/Pinnacles* – No Potential. Mostly Franciscan Formation and volcanic rocks.

Province 8 (Sonoma-Livermore)

- *Orinda Basin* is located within the Livermore Structural Play and lies immediately to the north of the Livermore Basin (BLM, 2015). The Pinol Point Field, which was discovered in 1969, was abandoned after producing 14,000 barrels of oil (BO) from the upper Miocene Neroly Formation and the Pliocene

Orinda Formation. This basin falls outside of an identified petroleum play documented in the CCST ISAs, and thus, has been classified as having low future potential (CCST, 2015, p. 253).

- *Livermore Basin*, which is within the Livermore Structural Play, is bounded on the west by the Sunol-Calaveras fault and on the north, east, and south by non-prospective pre-Tertiary rocks. This basin contains more than 20,000 feet of folded and faulted Neogene sedimentary fill, and may have formed as the result of wrench faulting on strike-slip faults. Although there are two active oil and gas fields within this basin, the levels of production in these fields are minor and the basin falls outside of an identified petroleum play documented in the CCST ISA (CCST, 2015, p. 253). Therefore, the Livermore Basin has been classified as having low future potential.
- *Other areas outside of Livermore Structural Play* – Low.
- *Diablo Range* – No Potential. Mostly Franciscan Formation and volcanic rocks.

Province 10 (San Joaquin Basin)

- *Clear Creek* – No Potential. Although nearly the entire area in the San Joaquin Basin has been assessed as being within an oil and gas play by the USGS, extensive outcrops of Franciscan assemblage also occur. This area is underlain by ultramafic rock.

Province 11 (Central Coastal)

- *Pescadero Oil (hypothetical).* The area of this play appears to be the onshore, northeastern margin of a major offshore sedimentary basin, the Año Nuevo Basin (also known as the Outer Santa Cruz Basin). The CCST ISA (see also Table 6) shows “none” known petroleum volume and a “low” conventional and unconventional resource potential. This suggests that the future potential would be low in this hypothetical play (CCST, 2015, p. 253).
- *Bitterwater Oil (hypothetical)*. The Bitterwater Play contains only one commercial oil field, and that field is smaller than 1 MMBO. The CCST ISA (see also Table 6) shows “minor” known petroleum volumes and a “low” conventional and unconventional resource potential. This suggests that the future potential would be low in this hypothetical play (CCST, 2015, p. 253).
- *Montara Mountain* – No Potential. Granitic, metavolcanic, Franciscan Formation rocks.
- *Ben Lomond Area* – No Potential. Granitic, metamorphic, Franciscan Formation rocks.
- *Gabilan Range* – No Potential. Granitic rock.
- *Monterey Peninsula* – No Potential. Granitic rock.

Province 12 (Santa Maria)

The northern most portion of the Santa Maria Province extends into the CCFO area. The Santa Maria Province is generally bounded by the Sur-Nacimiento fault (on the east), but extends beyond that fault north of latitude 36°N to include the approximate extent of exposed pre-Cretaceous metamorphic basement rocks. Within the Santa Maria Province, there are no oil and gas plays in the CCFO area.

- *Northern Santa Lucia Range* – No Potential. Granitic, metamorphic, Franciscan Formation rocks.

2.4 Comparison of Oil and Gas Occurrence Potential with 2007 Hollister Field Office RFD Scenario

Based on further analysis of the geology of the area and updated information, the areas of oil and gas occurrence potential have been modified from the 2007 Hollister Field Office RFD Scenario for Oil and Gas. An explanation of the similarities and differences between the 2007 RFD Scenario and the current RFD Scenario is described below.

Although, there are some differences in the geometry, the Salinas Basin and Sacramento Basins are both shown as having high oil and gas occurrence potential in the 2007 and the current RFD Scenario. Likewise, the Santa Maria Province, Gabilan Range, and Diablo Range were determined to have no oil and gas occurrence potential in this RFD Scenario, as well as in the 2007 evaluation.

The area between Santa Cruz and Point Año Nuevo that is within the La Honda Play was classified as having moderate oil and gas occurrence potential in the 2007 RFD Scenario and herein. Other portions of the La Honda Play were classified as having high oil and gas occurrence potential in the 2007 RFD Scenario, but are now classified as moderate based on the CCST ISA data (see Table 6, Resource Volume and Unconventional Resource Potential in the CCFO Area, by Basin).

There are areas within the San Joaquin Basin classified as having low and moderate occurrence potential in the 2007 RFD Scenario. However, the USGS has identified petroleum plays in nearly the entire San Joaquin Basin within the CCFO, and based on the CCST ISA, almost this entire basin is now classified as having high oil and gas occurrence potential.

The 2007 RFD Scenario classified the Bitterwater Play (hypothetical) and Sargent-Hollister Play as having high oil and gas occurrence potential, however, these areas are now considered to have low oil and gas occurrence potential. The area to the north of Point Año Nuevo is within the Pescadero Play (hypothetical), which was classified as having moderate occurrence potential in the 2007 RFD Scenario, but has also been revised to low occurrence potential based on the CCST information.

Furthermore, the Orinda and Livermore Basins are determined to have low oil and gas occurrence potential, but they were classified as having moderate occurrence potential in the 2007 RFD Scenario. Likewise, within the Central Coastal Province, the area within the Neogene Play, north of the Salinas Basin, is determined to have low occurrence potential, but this area was classified as moderate in the 2007 RFD Scenario.

Finally, the Santa Clara Valley Play (hypothetical), west of the City of San Jose, is missing from the 2007 evaluation. In the 2007 RFD Scenario, the hills on both sides of the San Francisco Bay are shown as having no potential, however, with the identification of the Santa Clara Valley Play (hypothetical) and other gravity lows in the vicinity (San Leandro and Evergreen lows), these areas are now classified as having low oil and gas occurrence potential.

2.5 Future Oil and Gas Development

Most oil fields in California are located in reservoirs associated with structural traps at depths above the oil window. The oil window is defined as the range of depths for which a source rock, having undergone burial and heating, will generate oil. This is a function of the type of organic matter and the integrated time-temperature history of the source rock (CCST, 2014, p. 122). The location of the identified reservoirs relative to the oil window indicates that the oil in these petroleum systems has migrated from the source rocks to the reservoirs. While there have been few new onshore oil discoveries in the past two decades, the USGS estimated that almost 1.59 billion cubic meters (10 billion barrels of oil) can be recovered using existing technologies, including well stimulation methods, from the largest oil fields in the San Joaquin and Los Angeles Basins (CCST, 2014; p. 29).

Overall, there are five major sedimentary basins in California with reservoirs of known economically viable oil and gas resources (the Los Angeles, Ventura, Santa Maria, Salinas, and San Joaquin Basins), as shown on Figure 1 (Major Sedimentary Basins and Faults in California). Portions of the CCFO are within the San Joaquin Basin in San Benito and Fresno Counties and portions of the CCFO are within the Salinas Basin in Monterey County.

Based on the production history of these regions and the presence of shale formations in these areas, it is likely potential future oil and gas resource production will be centered in these five basins. Economic production potential lies primarily in the San Joaquin, Santa Maria, and Ventura Basins, principally in Santa Barbara and Kern Counties. Production potential also exists in San Luis Obispo, Ventura, Kings, Monterey and Los Angeles Counties.

The CCFO area includes portions of the Monterey Formation in the San Joaquin Basin and Salinas Basin, along with portions of the Kreyenhagen, Tumey and Moreno Formations in the San Joaquin Basin (CCST, 2014, pp. 149 to 150); the surface areas of these formations appear on Figure 2 (Major Formations in BLM Hollister Field Office Administrative Area). Portions of San Ardo, Coalinga, Jacalitos, Kreyenhagen, and Kettleman North Dome oil and gas fields overlie source rock that is Monterey-equivalent. The plays are within Monterey, San Benito, and Fresno Counties, and the eastern edge of the CCFO area in Stanislaus and Merced Counties. Figure 5 (Plays and Active Oil and Gas Wells) shows the plays and active oil and gas wells within the CCFO area. The discussion of future oil and gas development within the CCFO area focuses on the areas of these identified plays, which correspond to areas of high and moderate oil and gas occurrence potential shown in Figure 4 and discussed in Sections 2.1 and 2.2. Over 29,000 acres of the CCFO area, including over 4,000 acres of federal mineral estate, overlay the Monterey Formation play at the southeastern end of the CCFO area.

Furthermore, there are three general categories of prospective target areas for oil production involving well stimulation in California, including within the CCFO area. These targets include: (1) continued or increased oil production from discovered oil fields or similar undiscovered reservoirs; (2) organic-rich shales located deep in the basins within the oil window; and (3) oil-bearing shales in basins where little oil production has occurred. Each category is described in greater detail below.

The first target consists of continued or increased oil production from discovered oil fields (or similar undiscovered reservoirs) that produce from formations with low permeability (also known as tight oil formations). The producing oil reservoirs in these fields generally lie above the oil window, indicating that the oil has migrated upwards from deeper source rocks and is now contained by structural, stratigraphic, and/or diagenetic traps. Of these producing fields, many have oil sourced from the Miocene Monterey Formation (or Monterey Formation-equivalent rocks). A significant fraction of these fields also have oil reservoirs in the Monterey Formation, often hosted in diatomites, fractured siliceous shales, or in interbedded sandy turbidite deposits; the oil has migrated from the deeper active source rock into shallower reservoirs with overlying seals. (CCST, 2014, p. 124)

Well record search results indicate about 75 wells per month were fractured in California in the decade prior to 2012, rising to closer to 100 wells per month in 2012 to 2013 (CCST, 2015, p. 94). To date, 95 percent of the hydraulic fracturing well stimulation activity in California has been in the San Joaquin Basin, and specifically within the Monterey Formation diatomites in South Belridge, Lost Hills, and Elk Hills fields of the San Joaquin Basin in Kern County, all of which are outside of the CCFO area (CCST, 2015, p. 94; and CCST, 2014, pp. 124 to 125). Most of the rest of the well stimulation activity occurs in the Los Angeles and Santa Barbara/Ventura Basins, also outside of the CCFO area (CCST, 2015, p. 94).

Likewise, increased recovery in the San Joaquin Basin within the CCFO area would likely require stimulation methods. There is no history of hydraulic fracturing in the wells in San Benito County within the San Joaquin Basin. In the Salinas Basin, 17 percent or approximately 20-30 wells were hydraulically fractured out of 156 wells drilled between 2002-2006 in Monterey County; however, none of the 523 wells drilled in Monterey County since that time have records of being hydraulically fractured (CCST, 2015, pp. 349 to 350), as shown in Tables 2 and 3 in Section 1.

A second target area consists of organic-rich shales located deep in the basins within the oil window. These zones have not been a major target for oil exploration in California. However, shales, such as those within the Monterey Formation, have been the source rocks for much of the oil that has been discovered and produced in California. Depending on how much oil still remains in these rocks, there may be significant potential associated with these source rocks. Exploitation of the source rock would constitute a true shale oil play. This target corresponds to the Monterey Formation oil play described by U.S. EIA and discussed in Section 1 (Monterey Formation) above. However, estimates of the potential size of recoverable oil associated with this target are highly uncertain. (CCST, 2014, p. 125)

While reservoir stimulation techniques may improve natural gas production from these low permeability reservoir rocks sporadically, widespread development of unconventional gas resources in California using well stimulation appears unlikely (CCST, 2015; p. 19). Given the level of uncertainties regarding the distribution and abundance of oil retained in deep Monterey source rocks, or how successful production could occur, significant future production of this target is not expected. Even if some of the uncertainties are resolved, these advances are not likely to alter the RFD Scenario for federal minerals in the planning area for the next 15 to 20 years due to the geology of the region (see Section 3, RFD Scenario Assumptions).

A third potential target would be oil-bearing shales in basins where little oil production has occurred. Very little published information is available about these basins, except for some data relating to the presence and distribution of potential source rocks. (CCST, 2014, p. 126). In the CCFO area, basins having relatively little oil production include the Bitterwater, La Honda, Pescadero, Sacramento Gas, and Sargent-Hollister Basins. As shown in Table 6 (Resource Volume and Unconventional Resource Potential in the CCFO Area, by Basin), these areas also have a “low” resource potential for continuous unconventional resources according to the CCST; this is in contrast with “possible” levels of unconventional resource potential in the better-established San Joaquin and Salinas Basins (CCST, 2015, p. 253).

3. RFD Scenario Assumptions

For purposes of this document, we have assumed that all potentially productive areas are open under standard lease terms and conditions, except those areas designated as closed to leasing by law, regulation, or executive order. This section describes future trends and assumptions within the CCFO area that have been incorporated into the RFD Scenario. This RFD Scenario is applicable to all alternative scenarios, because the alternatives considered in the RMP Amendment/EIS consider which BLM-administered lands to open or close to leasing, which would not impact the RFD Scenario assumptions.

The history of activity for oil and gas exploration and development on federal lands within the planning area is extremely low compared to private minerals. In May 2014, the U.S. EIA announced that its 2011 projection for the estimated amount of recoverable oil from the Monterey Formation has been reduced by as much as 96 percent, meaning that the formation may only be capable of producing an estimated 600 million barrels of oil with existing technology in comparison to the originally estimated 15.4 billion barrels of oil. However, both estimates for oil resources from new plays in the deep source rocks in the Monterey Formation are highly uncertain (see Section 1.1). As discussed in Section 2.5 (Future Oil and Gas Development), given the level of uncertainties regarding the Monterey Formation source rock, significant future production of this target is not expected (CCST, 2015, pp. 15 to 19).

Therefore, this RFD Scenario assumes leasing and exploration will continue at levels consistent with historic development. In other words, oil and gas leasing and exploration trends are not likely to increase or decrease. Rather, oil and gas activity within the CCFO area over the next 15 to 20 years is likely to remain sporadic and primarily on non-federal lands. Furthermore, additions of new reserves are expected to continue the decline begun in 1990 in all management areas.

The past 10 to 15 years have seen both historic lows and historic highs in both oil prices and drilling. Between late 1998 and mid-2008, oil prices for the Midway Sunset field, which produces the largest on-shore volume of federal crude in California, rose from $6 per barrel to $120 per barrel, a 20-fold increase. However, U.S. and world economic conditions have significantly deteriorated since then, and Midway Sunset crude was down to approximately $25 per barrel in late 2009. As of February 2010, the price had risen to $69 per barrel, by mid-January 2011, to $86.25, and by mid-March 2011, to nearly $110 per barrel, where it held fairly constant until mid-2014. At that time, oil prices began a rapid decline down to the $40’s per barrel by early 2015, further demonstrating the volatility of crude prices. Consequently, there is no consensus among forecasters as to what the demand for oil will be in either the near term or long term. Most current forecasts are for demand to continue to drop in the near term to midterm and to remain depressed into the foreseeable future. (BLM, 2012)

Because oil and gas are worldwide commodities, events that occur globally may have significant effects on U.S. production. The political instability of other nations that have most of the world’s reserves changes regularly, causing difficulty in forecasting worldwide levels of petroleum supply and demand. In addition, the U.S. and worldwide economic conditions have changed dramatically within the last couple of years, causing further uncertainty. However, such large deviations in economic conditions surrounding the global (and domestic) supply and demand for oil are not likely to alter foreseeable development in the CCFO. This assumption is based on the experience of local experts with knowledge of leasing and exploration of federal minerals over long periods of time that included fluctuations in the global (and domestic) supply and demand for oil.

Even if there are advances in science and technology that resolve some of the uncertainty associated with the Monterey Formation source rock, these advances are not likely to alter the RFD Scenario for federal minerals in the planning area for the next 15 to 20 years due to the geology of the region. Therefore, all available scientific, industry, and government information indicates that absent currently unforeseen changes in oilfield technology, future oil and gas development within the CCFO area will continue as it has over the last 10 or 20 years.

4. Estimated Number of Wells

As noted above, in the last decade, nearly all well development occurred in the Coalinga, San Ardo, Lynch Canyon, and Jacalitos fields (see Table 4, Well Development Activity in Major Oil and Gas Fields Within the CCFO Area) where the federal share of mineral estate is approximately 1 percent. Recent activity indicates that an annual average rate of between 110 and 210 wells per year (approximately) have had first production or injection since 2002 in the region (basis of Table 4). Assuming that the development trend in this region is likely to continue for the next 15 to 20 years, up to 3,150 wells could be initiated over 15 years with over 99 percent of these wells located within the Coalinga, San Ardo, Lynch Canyon, and Jacalitos fields. Furthermore, assuming that the federal share of development is likely to remain roughly proportional to the federal share of mineral estate in these four most-active fields (1 percent), between zero and 32 development wells could be expected over 15 years on federal mineral estate within existing fields in the CCFO area.

Exploratory wells are not common in the CCFO area. Fewer than 1 percent of the wells counted in the CCFO area occur outside of existing administrative oil and gas field boundaries. Based on the history of oil and gas exploration in the planning area, very few exploratory wildcat wells (wells outside of the administrative boundary of existing oil and gas fields) would be drilled on federal mineral estate in the planning area during the life of this plan. The past trend indicating only 1 percent of wells are outside administrative field boundaries implies that roughly 32 exploratory wells would be drilled on lands within the CCFO planning area. Given that 11.6 percent of land in the planning area is federal mineral estate, 3 to 5 exploratory wildcat wells would be drilled on federal mineral estate in the CCFO area during the life of this plan and includes possible Monterey Formation exploration.

Although the success rate for wildcat wells has improved markedly during the past decade, largely due to improved seismic data from geophysical exploration, it is still unlikely that any new fields would be discovered by drilling on federal minerals, because there is so little activity in areas with a significant amount of federal mineral estate. During the past 30 years, only one new field was discovered within the CCFO boundary (the Bixler Gas field, a very small 1.5 square mile gas field that was discovered in Contra Costa County in 1993). (DOGGR Annual reports, 1985 through 2014, searching for fields with first production after 1985). This four well field produced a total of 5.6 BCF by the time it was abandoned in 2001 (DOGGR 2001 Annual Report). The rarity of new discoveries (one very small field that was discovered more than 20 years ago, which contained no federal land), combined with the fact that less than 25% of the high occurrence potential land in the CCFO boundary is federal mineral estate, results in a reasonable conclusion that: (1) It is far from certain that any new fields will be discovered, and (2) If a new field is discovered, it would contain less than 25% federal land, depending, of course, on where the field is discovered.

Given the limited extent of area of federal mineral estate within the entire planning area, it is unlikely that more than a total of 37 exploratory and development wells will be drilled on federal oil and gas leases. Well stimulation technologies and enhanced oil recovery techniques are assumed to be used on any or all of these wells.

While the large majority or even all of this activity is expected to occur in areas identified in this RFD Scenario as “high oil and gas occurrence potential,” there is always a possibility that federal minerals in other areas may see geophysical exploration, leasing, and even actual exploration and development drilling. It is highly unlikely that any wells in such an area would be productive, so any associated surface disturbance would likely be short term. As discussed in Section 3 (RFD Scenario Assumptions), given the level of uncertainties regarding the Monterey Formation source rock, significant future production of this target is not expected.

The basic assumptions of the number of wells in this RFD Scenario are summarized in Table 7 (CCFO Oil and Gas Well Development Scenario Assumptions) and discussed in greater detail below.

Table 7. CCFO Oil and Gas Well Development Scenario Assumptions

	Wells/Fields on Federal Mineral Estate	Basis of Assumption
New/Additional Fields Discovered	0	Exploration is not expected to lead to new producing field discoveries in CCFO area.
New/Additional Wells (exploratory)	3 to 5 wells	Roughly 1 percent of 3,150 wells drilled across entire CCFO planning area during life of plan are exploratory and 11.6 percent of these of these may occur on federal mineral estate.
New/Additional Wells within Existing Fields (development)	0 to 32 wells	Roughly 1 percent of 3,150 new production/injection wells in CCFO area over 15 to 20 years are on federal mineral estate.

5. Estimated Surface Disturbance

This section provides a description of potential oil and gas activities and associated ground disturbance estimates for geophysical exploration, drilling, and field development and production.

Ground disturbance assumptions associated with well drilling and development would remain largely the same as those in the Hollister Field Office RFD Scenario for Oil and Gas, which was included as Appendix F in the Record of Decision for the RMP for the Southern Diablo Mountain Range and Central Coast of California (BLM, 2007). The ground disturbance assumptions are described herein for the reader, and the total disturbance estimates have been updated to reflect the revised future trends and assumptions of oil and gas development stated below. In addition, assumptions associated with well stimulation technologies and enhanced oil recovery techniques have been explicitly stated in Section 6 (Other RFD Scenario Activities or Considerations) and incorporated into the RFD Scenario.

Table 8 (Reasonably Foreseeable Development Scenario Surface Disturbance Assumptions) summarizes the potential surface disturbance assumptions associated with the development scenario of zero to 32 new development wells, 3 to 5 exploratory wells, and geophysical exploration. The total surface disturbance caused by seismic operations, exploration drilling, and development would be up to 206 acres. Each component is described in greater detail in Sections 5.1 through 5.3.

Table 8. Reasonably Foreseeable Development Scenario Surface Disturbance Assumptions

Description	Number	Unit Surface Disturbance	Total Surface Disturbance
Exploratory Wells			
Well pads	3 to 5 wells	1 to 3 acres/well	3 to 15 acres
Roads (40' wide)	3 to 5 x 0.5 miles	4.8 acres/mile	7.2 to 12 acres
Development Wells			
Well Pads	0 to 32 wells	1 to 3 acres/well	0 to 96 acres
Roads (40' wide)	0 to 32 x 0.25 miles	4.8 acres/mile	0 to 38.4 acres
Facilities	0 to 8 facilities	1 acre/facility	0 to 8 acres
Seismic (2 tracks x 18'')	34 miles	0.36 acre/mile	12.25 acres
Pipeline (20' wide)	0 to 10 miles	2.4 acres/mile	0 to 24 acres
Total			**22.45 to 205.7 acres**

5.1 Geophysical Exploration

Geophysical exploration is conducted to determine the subsurface structure of an area and the potential for mineral resources. There are three geophysical survey techniques that are generally used to define subsurface characteristics through measurements of the gravitational field, magnetic field, and seismic reflections.

Gravitational Field Surveys and Magnetic Field Surveys involve small, portable measuring units that are easily transported by light off-highway vehicles, such as 4-wheel drive pickup trucks and jeeps, or aircraft. Both off and on-highway travel may be necessary. Although these two survey methods can take measurements along defined lines, it is more common to have a grid of distinct measurement stations. Surface disturbance resulting from these surveys is negligible, consisting almost exclusively of soil or vegetation compaction that persists no more than a few months.

Seismic Reflection Surveys are the most common of the geophysical exploration methods, and they produce the most detailed subsurface information. Seismic surveys are conducted by sending shock waves, generated by a small explosion or by mechanically beating the ground with a thumping or vibrating platform.

In the *explosive method*, small charges are detonated on the surface or in a shallow drill hole. The surface charge method uses 1- to 5-pound charges attached to wooden laths 3 to 8 feet above the ground. Placing charges lower than 6 feet usually results in destruction of vegetation, whereas placing the charges higher, or on the surface of deep snow, results in little visible surface disturbance. In the drill hole method, holes for the charges are drilled using truck-mounted or portable air drills. In general, this method uses 4 to 12 holes per mile of line, and a 5- to 50-pound explosive charge is placed in each hole, covered, and detonated. The shock wave created is recorded by geophones placed in a line on the surface. In rugged terrain, a portable drill carried by helicopter can sometimes be used. The vehicles used for a drilling program may include heavy truck-mounted drill rigs, track-mounted drill rigs, water trucks, a computer recording truck, and a light pickup.

In the *mechanical method*, four large trucks are usually used, each equipped with pads about 4-feet square. The pads are lowered to the ground, and the vibrations are electronically triggered from the recording truck. Once information is recorded, the trucks move forward a short distance and the process is repeated. Surface disturbance includes flattening of vegetation and compaction of soils.

In either type of seismic reflection surveys, existing roads and trails are used where possible. However, off-road travel is necessary in some cases. Several trips per day are made along a seismograph line, usually resulting in a well-defined two-track trail.

Two geophysical exploration projects have occurred on federal mineral estate within the CCFO area in the last 10 years. One geophysical seismic survey project is located in the Vallecitos Oil and Gas Field and encompasses 32,288 acres, including approximately 70 percent private lands and 30 percent under the jurisdiction of the BLM. The other 3-D geophysical survey project is located in the Kettleman Hills North Dome Oil and Gas Field and encompasses 129,995 acres, including approximately 9,349 acres of surface estate under the jurisdiction of the CCFO in Fresno County and the Bakersfield Field Office in Kings County. In addition to the projects on BLM-administered land, there have been only two other geophysical exploration projects on private land in the CCFO area since the 2007 RMP.

Therefore, it is expected that no more than 4 Notices of Intent, involving seismic reflection and gravity/ magnetic field surveys across federal surface, would be filed under all alternatives during the life of this plan. If that occurs, the total expected surface disturbance could be up to 12.25 acres, based on up to 34 miles of seismic lines and a two-track road with each track being 18 inches wide.

It is possible that much of the travel could be located on existing roads or other previously disturbed lands, and there could be some hand laying of lines, and that would result in less new disturbance. On the other hand, it is possible that actual disturbance could be greater if more vibroseis (a seismic exploration technique) or other vehicular traffic is done on slopes or wet ground and there is more "churning" of the soil by the trucks or more crushing of plants by the vibratory pads. There could also be increased disturbance if the seismic trucks have to go in areas where there are no existing roads or trails.

Regardless of what is proposed, the operator will be required to conduct operations in a manner that minimizes unnecessary disturbance and prevents undue and unnecessary degradation to the natural resources. This would include requiring the operator to stay on existing roads and trails when possible, and requiring the operator to either hand carry or use heliportable equipment in areas of special sensitivity.

5.2 Drilling Phase

After a parcel is leased, there may or may not be any actual disturbance. In fact, historically, a large majority of leases are relinquished without ever having any actual surface disturbance. In the event that an APD is submitted, a site specific evaluation will be made by the BLM to ensure compliance with NEPA requirements. Based on the results of that evaluation, additional Conditions of Approval may be added, and the operator may only begin construction after complying with lease stipulations and Conditions of Approval of the drilling permit. When a site requires construction of an access road, the shortest feasible route is usually selected to reduce the haul distance and construction costs. Environmental factors or a landowner's wishes may dictate a longer route in some cases. Drilling in the planning area is expected to be done using existing roads and construction of only short (approximately 0.5 mile long) roads to access drill site locations.

Most drilling is expected to occur in areas of land designated as "high oil and gas occurrence potential" (shown on Figure 4), which generally corresponds to identified oil and gas plays within the San Joaquin and Salinas Basins discussed in Section 2 (see also Figure 5). Most wells drilled would be vertical; however, a small percentage of recently installed wells in California have been horizontal. All but 3 of these horizontal wells, more than 99 percent of the total, were installed in pre-existing fields as defined by DOGGR. The 3 horizontal wells outside pre-existing fields were in Kern County, as are 92 percent of all horizontal wells drilled with a commencement date in 2012 or 2013. Outside of Kern County, 11 horizontal wells were installed in Fresno County, all in the Coalinga field; and 9 were installed in Monterey County, all in the San Ardo field. Finally, 3 fields in Ventura County and 2 fields in Los Angeles County each had 1 or 2 horizontal wells installed (CCST, 2015, p. 345 to 346).

During the first phase of drilling, the operator would move construction equipment over existing maintained roads to the point where the access road begins. Less than 0.5 mile of moderate duty access road per well with a gravel surface 20 feet wide is expected for construction. With ditches, cuts, and fill, the total width of surface disturbance would average 40 feet. The second part of the drilling phase is the construction of a drill pad 1 to 3 acres in size. The likely duration of well drilling, testing, and abandonment (if the well is unsuccessful) is 3 or 4 months per site. If the well is successful, the useful life could be several decades or even more. The total disturbance for each exploratory well and any new road is estimated to be 5.4 acres. The total surface disturbance caused by exploratory drilling of 3 to 5 wells over the life of this plan is expected to be no more than 10 to 27 acres.

5.3 Field Development and Production

Given past and current oil and gas development trends, uncertainty with development of the Monterey Formation source rock, and predicted future oil and gas development in the CCFO area, exploratory drilling is not expected to lead to the development of a producing field in the planning area within the 15 to 20 year projections included in this RFD Scenario and the RMP Amendment/EIS. Furthermore, even if a new field were developed, given the share of federal mineral estate within the CCFO area, the location of the areas of high and moderate oil and gas occurrence potential, and past and current trends of oil and gas development on private land, this field would not likely be located on federal mineral estate. Nonetheless, the following scenario describes the operations and effects associated with field development of up to 32 new development wells.

The minimum size considered economically feasible would depend mainly on its proximity to existing infrastructure. There are many fields within the boundaries of the CCFO area, mostly in the extreme southern and extreme northern portions of the planning area, and it is likely that any pipelines from a new field would be relatively short. In gas fields, wells within the actual productive boundaries, which are smaller than the administrative boundaries, are spaced on average at 80 to 160 acres. In larger oil fields, well density can be much higher, typically at 5 to 7 acres per well or up to an equivalent density of 128 wells per square mile. However, spacing can be as close as one or more wells per acre in areas with heavy oil.

Table 8 (Reasonably Foreseeable Development Scenario Surface Disturbance Assumptions) summarizes the potential surface disturbance assumptions associated with the development scenario of up to 32 new development wells in a new field. Each development well would require an estimated 0.25 mile of road, which would have a surface of crushed aggregate or gravel approximately 20 feet wide (total disturbed width of 40 feet). Well pads would be no more than 1 to 3 acres in size. Oil and gas produced would be carried by pipelines that could be linked to existing and proposed transmission lines in the planning area. Average infield pipeline length is estimated to be 0.25 mile per well, which could probably be largely contained within the road right-of-way and little new surface disturbance would be required. The total distance from a new field to an existing transmission pipeline is likely to be less than 10 miles. The width of the surface disturbance for pipelines would average 20 feet.

The maximum total surface disturbance for 32 development wells is shown in Table 8 and would be 96 acres for well pads, 38.4 acres for roads, and 24 acres for 10 miles of transmission pipeline. No more than 1 acre would be required for the small facility (meter, separator) on each parcel. For planning purposes, it is assumed that the wells may be on 8 separate parcels, so there would be a total of 8 acres for facilities. The total surface disturbance caused by development wells would be up to approximately 166 acres, as shown in Table 8 (Reasonably Foreseeable Development Scenario Surface Disturbance Assumptions).

6. Other RFD Scenario Activities or Considerations

This section provides a description of potential oil and gas activities for well stimulation, enhanced oil recovery, wells operations and maintenance, plugging and abandonment, and oil and gas activity on military bases.

The RFD Scenario also considers wells required for groundwater monitoring in areas of oil and gas well stimulation and underground injection control wells. As required by the State Water Resources Control Board Draft Model Criteria for Groundwater Monitoring in Areas of Oil and Gas Well Stimulation, the RFD Scenario assumes a minimum of one upgradient and two downgradient monitoring wells for each protected aquifer that is penetrated by the stimulated well. This does not change the number of assumed wells in the RFD Scenario as the monitoring wells may use already existing wells or multiple oil and gas wells may use the same monitoring wells. The types of activities required to drill a new monitoring well are similar to those described in Section 5, Estimated Surface Disturbance. Underground injection control wells are discussed below in the stimulation technologies.

6.1 Well Stimulation Technologies

Depending on the type of formation and the current state of the wellbore, well stimulation, such as hydraulic fracturing, acid matrix stimulation or acid fracturing, may be required on any or all of the wells. Only one of these treatments for the purposes of well stimulation would be used on any given well. Well stimulation treatment operations would occur entirely within the well pad and no additional ground disturbance would be anticipated beyond what is described in Table 8 (Reasonably Foreseeable Development Scenario Surface Disturbance Assumptions).

Of the zero to 32 development wells and 3 to 5 exploratory wells that are anticipated to be drilled within the CCFO area, it is assumed that well stimulation technologies could be used on any or all of these wells. Well stimulation is anticipated to be performed primarily on wells located in high potential occurrence zones. Hydraulic fracturing, acid matrix stimulation, and acid fracturing are described in greater detail below.

Enhanced oil recovery (EOR) techniques, which are used to increase production over the life of a well, may be used in conjunction with well stimulation technologies. The CCST ISAs focus on well stimulation technologies for reservoirs that are unconventional because of low permeability. Therefore, EOR methods for reservoirs that contain viscous oils are not addressed in detail in the reports. EOR within the CCFO area under this RFD Scenario is discussed in a separate section (Enhanced Oil Recovery) below.

Hydraulic Fracturing

Hydraulic fracturing is not part of the drilling process. It is a well completion technique to stimulate the well and maximize the extraction of underground resources from the target zone. Hydraulic fracturing is applied after the well is drilled, several strings of protective steel casing are cemented in place, and the wellbore has been perforated. The process of hydraulic fracturing injects highly pressurized fluids and sand (called "proppant") into a geologic formation, which creates and props open fissures, or pathways, through which the produced fluids can more easily flow into the wellbore.

Hydraulic fracturing has been used as a production stimulation method in California since the late 1960s. However, fewer than 25 percent of all wells drilled within the State are hydraulically fractured, and the vast majority of past and currently recorded fracturing activities occurs in the southwestern portion of the San Joaquin Valley, in Kern County, outside of the CCFO area (DOC, 2015, p. 7-25; CCST, 2014, p. 25).

There are several steps during the hydraulic fracturing process that together make up one "stage." Hydraulic fracturing treatments are delivered, one section or "stage" at a time, starting at the deepest extent in a vertical well, or at the farthest end of a horizontal well, and then working back towards the top of the producing zone, or where a directional well curves from horizontal to vertical and the entire horizontal length of the well has been fractured. Although overall a horizontal well can be much longer than a vertical well, the hydraulic fracture treatment targets an individual zone; as such, the amount of water, sand, and additives used are the same, *stage for stage* within this individual zone. (DOC, 2015, p. 7-29). The overall length of the well to be stimulated determines the number of stages and the overall amount of water, proppant, and chemical additives required.

The majority of the oil produced from fields in California is not from within the source rock (e.g., shale in the Monterey Formation), but rather from geologically limited reservoirs containing oil that has migrated from source rocks. These reservoirs do not resemble the extensive and continuous layers that are amenable to oil production with high water-volume hydraulic fracturing from long-reach horizontal wells, such as found in the Bakken in North Dakota and Eagle Ford in Texas (CCST, 2015 p. 153).

In California, a typical hydraulic fracturing “job” occurs in a shallow vertical well and contains only 1 to 5 stages. However, there could be up to 20 stages in a deep horizontal well during exploration of the Monterey Formation source rock. Each stage may include the injection of an acid preflush (not generally used in California); fluid without proppant (called “pad”); fluid that contains proppant; and then water to flush excess proppant back up the well. For a typical job, the total on location time is approximately 16 hours with 8 to 15 employees on each shift (DOC, 2015, p. 7-33). This time does not include site preparation by the operator (including water transport and storage at the site) or flow back of the fluids from the hydraulic fracturing treatment and from the reservoir formation to the surface.

Water and proppant make up approximately 99.5 percent of the fluid used in hydraulic fracturing. Of that, in California, 75 percent is typically water and 25 percent is typically sand (DOC, 2015, p. 7-36). Although there is considerable variation, average water use for hydraulic fracturing in California has been approximately 130,000 to 210,000 gallons per operation based on voluntary disclosures by operators in the FracFocus database (CCST, 2014, p. 26)[7]. In addition, 200 to 500 tons of proppant are typically used for a hydraulic fracturing treatment in California (DOC, 2015, p. 7-37).

Chemical additives used in well stimulation fluid consist of a blend of common chemicals that increase water viscosity, help extend the fracture, and suspend/transport the proppant and water mixture farther out into the fractures (tens to hundreds of feet). Additives also control bacterial growth, minimize swelling of clay particles in the formation, and inhibit corrosion to help maintain the integrity of the well. Additives include gels, foams, and other compounds. These other liquid and solid additives that may be incorporated in the fracturing fluid consist of the following: surfactants, a soap-like product designed to enhance water recovery; friction reducers; biocides to prevent microorganism growth; oxygen scavengers and other stabilizers to prevent corrosion of metal pipes; and acids to remove drilling mud damage. Some of the additives are recovered in the water that flows back after the hydraulic fracture treatment (15 to 80 percent, depending on the specific treatment job), and most of the remainder is recovered once the oil or gas well is brought into production. The hydraulic fracturing product additives that may be used for fracturing the Monterey Formation source rock in the future would likely contain chemical constituents similar to the types of products that have been used to date for the hydraulic fracturing of traditional oil and gas reservoirs in California, including the Monterey Formation. (DOC, 2015, p. 7-38)

Equipment required for a typical hydraulic fracturing operation would include the following:

[7] Water usage for hydraulic fracturing in California is considerably less than in other hydraulically fractured plays in the United States. For instance, average water use per operation in a horizontal well in the Eagle Ford in Texas is 4.25 million gallons. The difference results in part from the predominance of hydraulic fracturing in relatively shallow vertical wells in California, which have shorter treatment intervals, as compared to the predominance of horizontal wells in major unconventional oil plays like the Eagle Ford and Bakken, as well as the use of gel as opposed to slickwater in those other plays. (CCST, 2015, pp. 150 to 151)

- Control Vans
- Pump Trucks
- Flatbed
- Manifold/Treating Iron Trailer
- Tanker/Mixer (5,000 gallon)
- Blender
- Crane
- Sand Chiefs (150-ton capacity)
- Pickup Trucks or Vans
- Water Tanks (500 barrel laydown tanks or 400 barrel upright tanks)
- Water Trucks (4,000 or 5,000 gallon) (if not available via pipeline)
- Sand Trucks (25-ton capacity)

Aside from water and proppant delivery, each vehicle is assumed to have one round trip to the site. However, for a multi-day operation, pickup trucks, vans, or personal vehicles typically deliver the crew to the site each day. (DOC, 2015, p. 7-43)

At the conclusion of all hydraulic fracturing stages, "flowback" fluids are brought up through the well-bore to the surface by the well operator. The composition and amount of flowback recovered depends on the characteristics of the targeted formation and the specific fluid used for the hydraulic fracturing job. Remaining fracturing fluid that does not flow back immediately is recovered from the well along with oil, gas and produced water slowly over time. Flowback fluids are either temporarily stored in tanks onsite, or flowed directly into a production pipeline where hydrocarbons and produced water are subsequently separated at a processing facility (DOC, 2015, p. 7-36). California's regulations (published March 26, 2015) require all flowback to be contained in storage tanks onsite prior to final disposition. Flowback and produced water, collectively known as wastewater, is typically handled in the following ways: (1) injected (with or without treatment) into water disposal/enhanced recovery wells; or (2) recycled (with or without treatment) for use in future oil and gas operations, including hydraulic fracturing or injection into the target hydrocarbon formation (DOC, 2015, pp. 7-39 to 7-40). Additionally, some produced water is permitted to be recycled for irrigation and livestock watering (CCST, 2014, pp. 212 to 213). Wastewater may also be trucked or piped to an offsite private or municipal wastewater treatment plant, but this method is rarely used because it is more costly and many treatment facilities are not configured to treat wastewater having high levels of total dissolved solids (TDS) that occur with produced water (DOC, 2015, p. 7-40).

Acid Matrix Stimulation

Acid matrix stimulation or matrix acidizing is practiced in California, but the majority of acid matrix stimulation also occurs in Kern County, outside of the CCFO area. Acid matrix stimulation involves pumping acid into a well at a pressure low enough to prevent a reservoir rock from fracturing. Acid matrix stimulation is smaller in scope than hydraulic or acid fracturing, and is performed in one day or less. There are two types of matrix acidizing. One type of matrix acidizing, which has a volume of fluid less than the Acid Volume Threshold[8] and typically affects an area less than 5 feet from the wellbore, is used to remove damage from drilling or scale that has built up over several years of production. This acid treatment may be used routinely over the life of a well and is not used for the purpose of well stimulation. Therefore, this acid treatment or rework is not considered in this RMP Amendment/EIS.

[8] According to DOGGR's final text of regulations that would amend California Code of Regulations Title 14, Division 2, Chapter 4, Subchapter 2, Article 2 (Definitions), "Acid Volume Threshold" means a volume, in U.S. gallons, per treated foot of well stimulation treatment, calculated as follows: (((Size of the drill bit diameter in inches that was used in the treated zone/ 2 + 36 inches)^2 – (bit diameter in inches/ 2)^2) × 3.14159 × 12 inches × treated formation porosity)/ 213 (inches^3/gallon). The lowest calculated or measured porosity in the zone of treated formation shall be the treated formation porosity used for calculating the Acid Volume Threshold.

Beyond approximately 3 to 5 feet from the wellbore, matrix acidizing is used as a well stimulation technique and is analyzed in this RMP Amendment/EIS, as described below.

The types of acid used (or not used) in acid matrix stimulation are dependent on the formation. The most common acid systems used are hydrochloric acid (HCl) in carbonate formations and hydro-fluoric/hydrochloric acid (HF/HCl) mixtures in sandstone formations (CCST, 2014, p. 22). Although most acid stimulation jobs use HCl and/or a mud acid, other acids may be used, such as citric acid and formic acid. Typically acid is mixed and diluted to its final strength before arriving at the well site. For instance, raw acid (36 percent HCl) would be delivered to the service company's facility. It would then be diluted at the facility to 15 percent or lower concentration or would be blended at a ratio of 12:3 (i.e., 12 percent HCl and 3 percent HF) prior to transport to the well site. The diluted acid is typically transported to the well site in a lined 5,000-gallon tanker transport, and stored in the transport or in plastic poly tanks at the site until it is used. (DOC, 2015, p. 7-47)

At the well site, water would be blended with the already diluted acid at a 50:50 or higher ratio as it is pumped into the wellbore (e.g., at least 500 gallons of water with 500 gallons of the acid blend). A slightly greater than 50 percent ratio of water is used for jobs designed to reach farther into the formation from the wellbore (DOC, 2015, p. 7-47). Planned water use listed in notices submitted to DOGGR in December 2013 and January 2014 for such treatments ranged between 8,000 to 140,000 gallons with an average of 42,000 gallons (CCST, 2014, p. 114).

On average and depending on the job's design, an acid matrix stimulation treatment takes up to 8 hours with 3 to 10 vehicles needed. Typically each worker is assigned to a vehicle for the duration of the job, and each job requires one roundtrip to the well site for each vehicle to complete the treatment. (DOC, 2015, p. 7-47 to 7-48)

Acid Fracturing

Acid fracturing, also called fracture acidizing, accomplishes the same goal as hydraulic fracturing by injecting low pH fluids instead of proppant into a created fracture. The acid is intended to non-uniformly etch the walls of the fracture so that some fracture conductivity is maintained after the fracture closes (CCST, 2014, pp. 70-71). Acid fracturing is used primarily in carbonate reservoirs, which do not generally occur in California. Therefore, this method is rarely used within the State, and no acid fracturing treatments are anticipated within the CCFO area.

6.2 Enhanced Oil Recovery

EOR is the implementation of various techniques for increasing the amount of crude oil that can be extracted from an oil field over the life of a well. EOR techniques include (1) thermal recovery using heat; (2) gas injection using carbon dioxide (CO_2), natural gas, or nitrogen; or (3) chemical injection using long-chained molecules called polymers to increase the effectiveness of waterfloods.

Gas injection accounts for nearly 60 percent of EOR production in the United States; however, it is used primarily in west Texas and the southern Rocky Mountains and not within California. Chemical tech-niques account for only about 1 percent of U.S. EOR production due to its relatively high cost and, in some cases, the unpredictability of its effectiveness (DOE, 2015). Chemical injection is not anticipated within the CCFO area under this RFD Scenario.

Thermal recovery, which makes up 40 percent of EOR production in the United States, is primarily used in California, and is the primary method of EOR within the CCFO area (DOE, 2015). It may be used in combination with well stimulation, such as hydraulic fracturing. Methods of thermal recovery that may be used include cyclic steam injection and steam flooding. In general, steam injection forces pressurized steam into the reservoir to heat and reduce the viscosity of the oil, which allows it to flow more readily to production wells. Cyclic steam injection or steam cycling is a form of steam injection in which injection and production take place in the same well, which is accomplished by alternating steam injection with oil production. Steam flooding involves continuous steam injection into wells interspersed among the production wells.

Water flooding, the most widely used secondary recovery method in the country, is also used within the CCFO area and includes injection of water into the reservoir, usually to increase pressure and thereby stimulate production. The water may also sweep or displace oil from the reservoir, and push it towards a well.

Flowback (if a well is stimulated) may be disposed into Class II wells, and produced water is often reused and injected into Class II wells for EOR. Based on data provided by DOGGR, there were approximately 35,000 active Class II[9] wells in California in 2013. Approximately 5 percent of these wells were used for water and gas disposal, while the remaining were used for EOR (i.e., cyclic steam, steam flood, and water flood) (DOC, 2015, p. 10.13-15).

DOGGR first reported the portion of oil produced by water flooding and steam injection in California in 1989. It attributed 71 percent of oil production in that year to these techniques. A total of 76 percent of production in 2009, the most recent year with attribution, was due to these techniques (CCST, 2015, p. 4). Likewise, EOR is the main recovery method used within the CCFO area. About 85 percent of the production from the Coalinga Field is from thermal recovery projects (DOGGR, 2010, p. 43). EOR techniques are utilized in all of the most productive oil and gas fields within the CCFO area, which are discussed in Section 1 and listed as follow (DOGGR, 2010, pp. 177 to 191):

- Coalinga Oil and Gas Field with Coalinga East Extension Oil and Gas Field (steam flood, cyclic steam, and water flood);
- San Ardo Oil and Gas Field (steam flood, cyclic steam, and water flood);
- Lynch Canyon Oil and Gas Field (cyclic steam);
- Jacalitos Oil and Gas Field (cyclic steam and water flood);
- Kettleman North Dome Oil and Gas Field (water flood); and
- Sargent-Hollister Oil and Gas Field (cyclic steam).

Therefore, similar to well stimulation technologies discussed above, it is estimated that EOR techniques (i.e., cyclic steam and steam flood) and secondary recovery techniques (water flood) may be used on any or all wells under this RFD Scenario. Likewise, EOR and secondary recovery operations would occur entirely within the well pad and no additional ground disturbance would be anticipated beyond what is described in Table 8 (Reasonably Foreseeable Development Scenario Surface Disturbance Assumptions).

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9 Injection wells are classified by the U.S. Environmental Protection Agency into six classes according to the type of fluid they inject and where the fluid is injected. Class II wells inject fluids associated with oil and natural gas production operations. Most of the injected fluid is brine that is produced when oil and gas are extracted from the earth.

6.3 Well Operations and Maintenance

During the life of a well, rework, including acid treatments, may be necessary to restore production from an existing formation when it has fallen off substantially or ceased altogether. All operations other than drilling new wells and abandoning existing wells are under the general classification "rework." Typical routine well maintenance would occur at the surface and downhole, and would consists of repair or replacement of wearable parts that have a limited service life or maintaining the tubing, wellbore or other downhole devices to maintain optimum efficiency. (DOC, 2015, p. 7-17 to 7-18)

Production operations would vary from field to field, but most are 24 hours per day, seven days per week and 365 days per year. From the production facility, most oil and gas is piped through a large network of existing crude oil pipelines to refineries clustered in the Los Angeles area, the San Francisco Bay Area (within the CCFO area), and the Central Valley near Bakersfield (DOC, 2015, p. 7-19).

6.4 Plugging and Abandonment

Wells that have reached the end of their productive life (usually when the cost to operate them exceeds the value of the production) or are drilled and determined to be dry holes are plugged according to an approved engineering design for the condition of each well. Plugging involves placing cement slurry or plug at strategic depths in the hole across all fresh water zones and up to the surface and in annular spaces as needed. Drilling mud is used as a spacer between the plugs to prevent communication between fluid-bearing zones. The drill casing is cut off at least 5 feet below ground level and capped by welding a steel plate on the casing stub. After plugging, all equipment and debris would be removed and the site restored as near as reasonably possible to its original condition. It is projected that much of the surface disturbance from exploratory activities and all of the seismic activities would be of short duration (between a few months and a couple of years). The impacts from the successful development wells would last longer, but it would still be completely reclaimed eventually.

6.5 Military Bases

Fort Hunter Liggett military base is within the planning area. Leasing these lands requires consent from the local Base Commander**.** It has been shown in numerous cases across the country and within California that oil and gas exploration and development can often be conducted in a manner that is fully compatible with ongoing military operations. It is quite possible that negotiations between BLM and military personnel may result in agreement to lease lands within the boundaries of bases or other military lands. In the event that happens, appropriate leasing stipulations that would fully protect the military's mission will be added prior to any land being leased.

7. RFD Scenario Considered but Eliminated

Given past and current oil and gas development trends, uncertainty with development of the Monterey Formation source rock, and predicted future oil and gas development in the CCFO area, exploratory drilling is not expected to lead to the discovery and development of a large new producing field in the planning area within the 15 to 20 year projections included in this RFD Scenario and the RMP Amendment/EIS. Any field discovered would likely be small (a few hundred acres or less). Furthermore, if a new field were developed, given the share of federal mineral estate within the CCFO area, the location of the areas of high and moderate oil and gas occurrence potential, and past and current trends of oil and gas development on private land, this field would not likely be located on federal mineral estate. Nonetheless, BLM considered the following scenario, which describes the operations and effects associated with field development.

The surface disturbance and well density assumptions for a new field would be similar to those included in Section 5 (Estimated Surface Disturbance). If a field containing BLM-administered federal mineral estate were to be discovered in the northern portion of the CCFO area, it is likely that the discovery would be gas because all of the occurrences in that area are gas. Conversely, if a field containing federal mineral estate were to be discovered in the southern portion of the CCFO area, it is likely that the discovery would be oil because all of the occurrences in that area are oil.

A planning assumption that BLM considered would be for discovery of a small- to mid-size oil field, or an equivalent level of oil and gas development in the CCFO area within and nearby to active fields. The average field size in the CCFO area is over 1,900 acres, but that is significantly skewed by the presence of a few very large fields. The smallest 80 percent of the active fields in the CCFO area have an average size of 650 acres, about one square mile.

If a single new oil and gas field of 650 acres was discovered, on average it would contain 11.6 percent federal mineral estate, about 75 acres (see Table 1 in Section 1). At a spacing of 5 to 7 acres per well, it would take approximately 13 wells to fully develop the 75-acre federal parcel. In the highly unlikely event that this new oil and gas field were to be located entirely on federal mineral estate, then up to approximately 108 wells would be drilled under this maximum level of development scenario. The basic assumptions are summarized in Table 9 (Oil and Gas Development Scenario Assumptions Considered but Eliminated).

Table 9. Oil and Gas Development Scenario Assumptions Considered but Eliminated

	Assumption	Basis of Assumption
New/Additional Fields Discovered	1	Discovery of a small- to mid-size oil field.
New/Additional Oil and Gas Fields Area	75 to 650 acres	Average active field size for smaller fields in this area is 650 acres; approximately 11.6 percent of CCFO area is federal mineral estate.
Assumed Well Spacing	5 to 7 acres per well	Typical well density in existing larger oil fields in CCFO area.
New/Additional Wells (development)	13 to 108 wells	Result of well spacing across the range of new/additional area of fields (i.e., high end is 108 wells spaced at ~6 acres per well over 650 acres of a new field located entirely within federal mineral estate).

Based on the surface disturbance assumptions in Table 8 (Reasonably Foreseeable Development Scenario Surface Disturbance Assumptions), the maximum total surface disturbance for 108 development wells in a new field would be 108 acres for well pads, 518 acres for roads, and 24 acres for 10 miles of transmission pipeline. No more than 1 acre would be required for the small facility (meter, separator) on each parcel. For planning purposes, it is assumed that the wells may be on 10 separate parcels, so there would be a total of 10 acres for facilities. The total surface disturbance caused by development of the new field would be up to 660 acres.

However, based on the updated oil and gas occurrence potential as well as predicted future oil and gas development in the CCFO area discussed herein, this field development scenario is extremely unlikely to occur. Therefore, it was considered, but not incorporated in this RFD Scenario.

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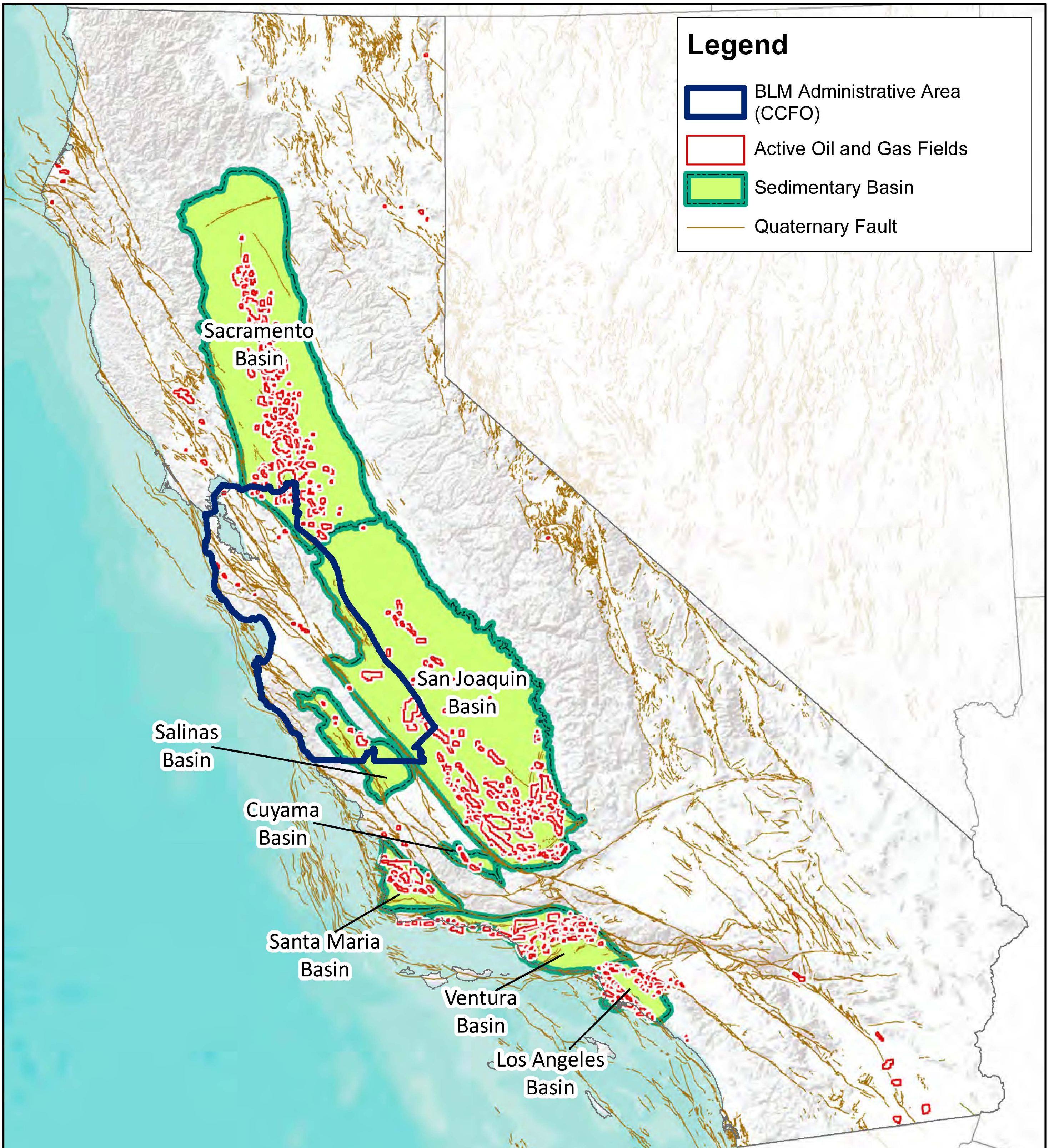

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Km

Map Reference:
UTM Zone 10 NAD83

Scale 1:5,000,000

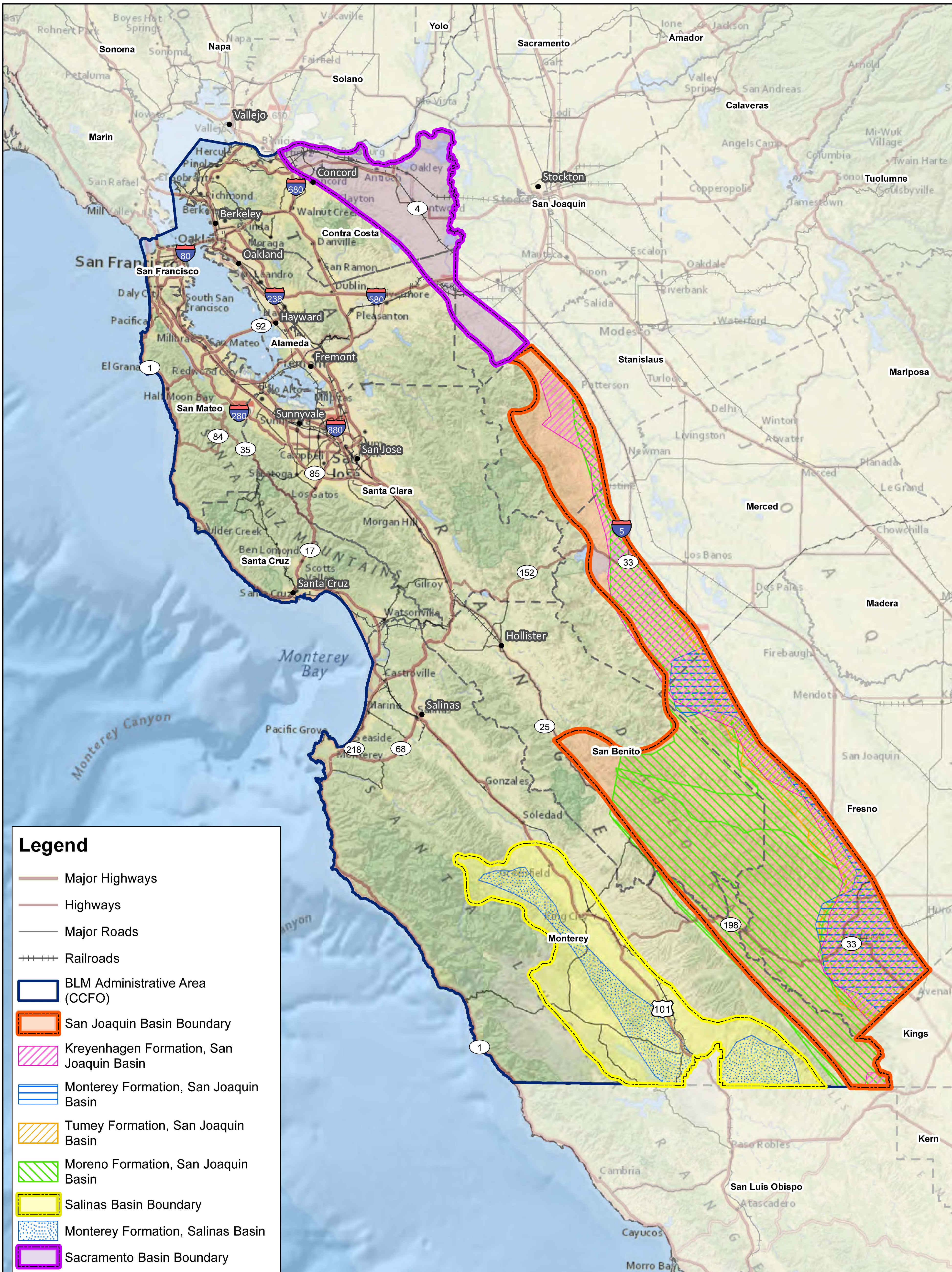
BUREAU OF
LAND MANAGEMENT

CENTRAL COAST
FIELD OFFICE

Figure 1

Major Sedimentary Basins and Faults in California

Date: October 2015



0 5 10 20 30 40
Mi
0 10 20 40 60 80
Km

NATIONAL SYSTEM OF PUBLIC LANDS
U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

Map Reference:
UTM Zone 10 NAD83

Scale 1:1,000,000

N W E S

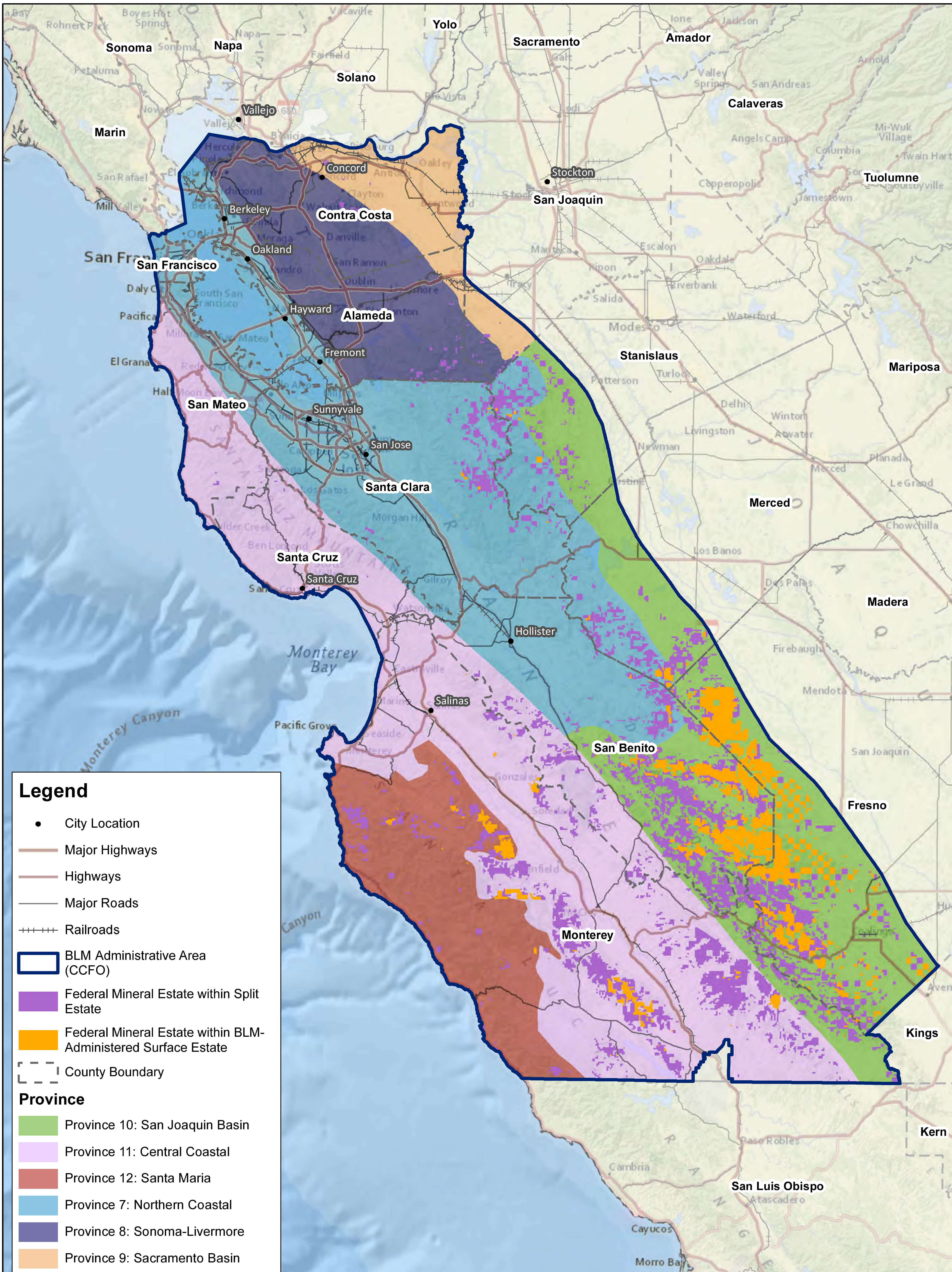
BUREAU OF LAND MANAGEMENT

CENTRAL COAST FIELD OFFICE

Figure 2

Major Formations in BLM Central Coast Field Office Administrative Area

Date: October 2015



0 5 10 20 30 40
Mi
0 10 20 40 60 80
Km

Source: BLM, 2015

Map Reference:
UTM Zone 10 NAD83

Scale 1:1,000,000

N W E S

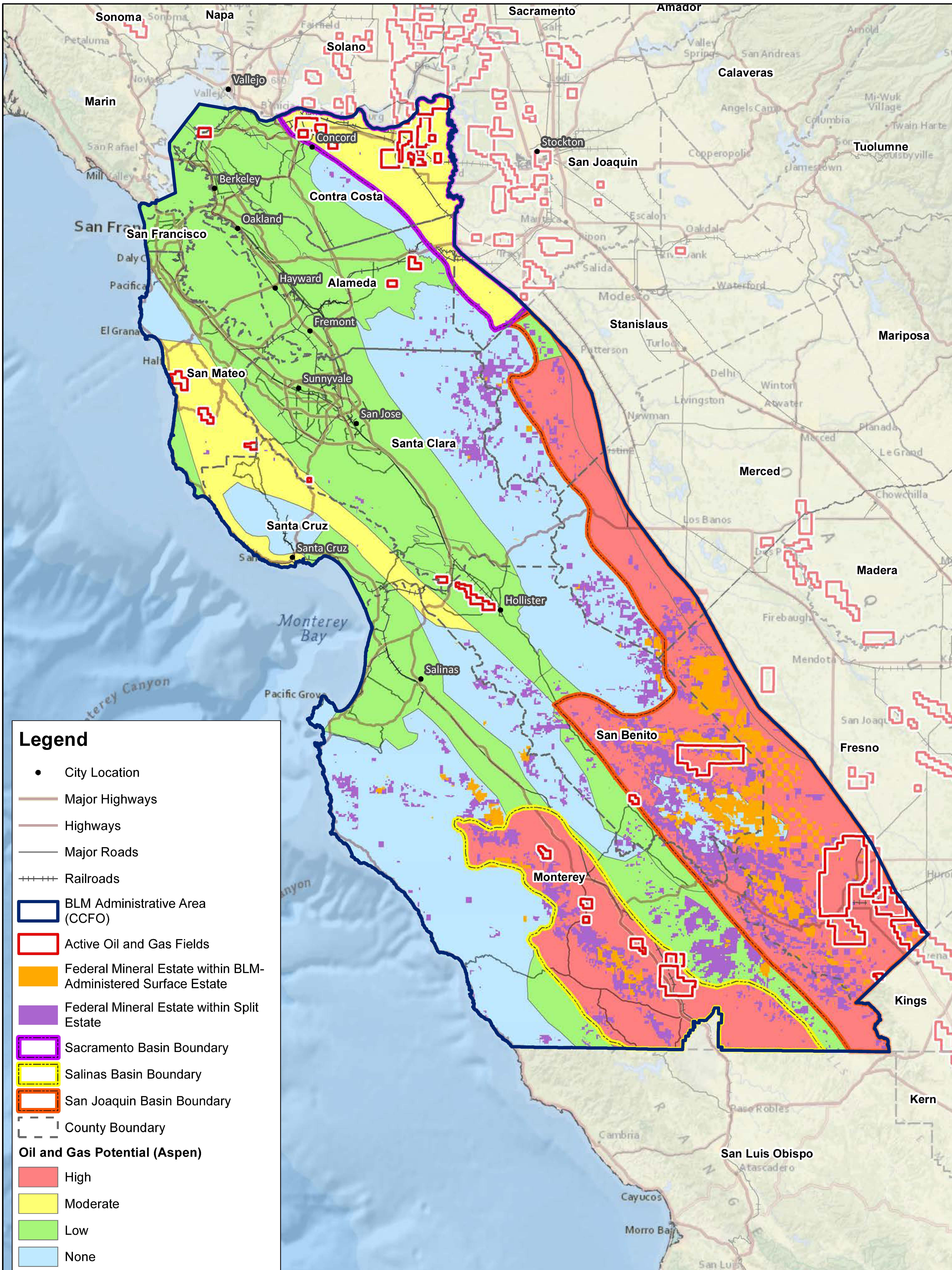
BUREAU OF LAND MANAGEMENT

CENTRAL COAST FIELD OFFICE

Figure 3

Oil and Gas Provinces within the BLM Central Coast Field Office Administrative Area

Date: October 2015



0 5 10 20 30 40
Mi
0 10 20 40 60 80
Km

Source: BLM, 2015

Map Reference:
UTM Zone 10 NAD83

Scale 1:1,000,000

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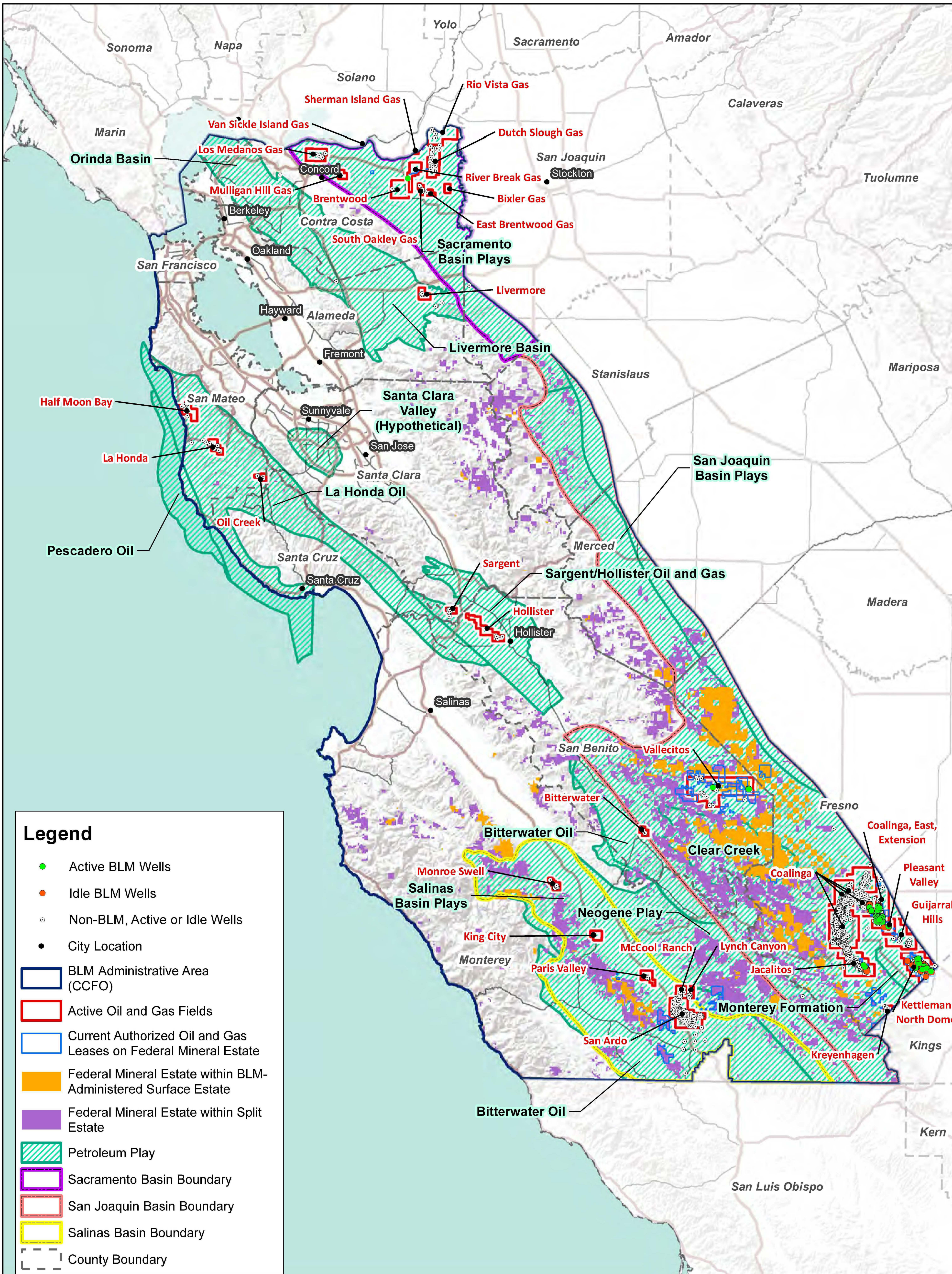
Figure 4.

Oil and Gas Occurrence Potential

Date: October 2015



0 5 10 20 30 40
Mi
0 10 20 40 60 80
Km

NATIONAL SYSTEM OF PUBLIC LANDS
U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

Map Reference:
UTM Zone 10 NAD83

Scale 1:1,000,000

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Figure 5

Plays and Active Oil and Gas Wells within the BLM Central Coast Field Office Administrative Area

Date: October 2015