2.0 Proposed Project Description & Alternatives

2.1 Project Overview

Aera Energy LLC (Aera or "Applicant") is proposing the East Cat Canyon Oil Field Redevelopment Plan ("Project") to re-establish oil production on its property and lease holdings within the Cat Canyon Oil Field, approximately 7 miles southeast of Santa Maria in northern Santa Barbara County. The proposed Project includes a request to the County of Santa Barbara (County) for the approval of an Oil and Gas Drilling and Production Plan and, Vesting Tentative Tract Map, for the construction and operation of the proposed Project, as follows:

- Oil Drilling and Production Plan (ODPP) (County Case No. 15PPP-00000-00001) to allow for reestablishment of oil and gas production operations.
- Vesting Tentative Tract Map (15TRM-00000-00003) to reconfigure 14 lots into 12 lots for the approval of an Oil and Gas Drilling and Production Plan and Vesting Tentative Tract Map.

Aera proposes to re-establish oil production at a forecasted level of up to 10,000 barrels of oil per day by implementing a thermal enhanced oil recovery process within the Sisquoc Formation (reservoir) underlying the eastern area of the existing Cat Canyon Oil Field. To do so, the Project wells, roads, utility and transportation infrastructure would be built out in two phases, Phase I and Phase II. The operational results and monitoring data collected from Phase I would help to confirm the Project's reservoir models and production forecasts, prior to additional investment and construction. Production from the Project is expected to continue for 30 to 50 years or more after initial production unless or until it is deemed uneconomic or undesirable to continue operation.

The proposed Project includes the following components:

Aera Oil Field Redevelopment

- **Well Pads** – Construction and restoration of approximately 72 well pad locations.
- **Wells** – Development and operation of up to 296 wells, including oil/gas production wells, steam injection wells, observation wells, non-potable water production wells, water injection wells, and fresh groundwater wells. No hydraulic fracturing would be used for this Project.
- **Access Roads** – Construction and restoration of over 9 miles of field access roads.
- **Processing Facilities** – Construction of new processing facilities, including:
  - Production group station for bulk separation of produced gas and liquids;
  - Central processing facility for oil cleaning, water cleaning, water softening, oil storage, and oil sales; and
  - Steam generation site with up to six once-through steam generators rated at 85 million British thermal units/hour (BTUs) each, a seventh once-through steam generator rated at 62.5 million BTUs/hour, an emergency flare, and ancillary facilities;
- **Field Systems** – Construction of new field systems, including
  - Production gathering and water distribution network;
  - Steam distribution network; and
  - Electrical power distribution, and supervisory control and data acquisition (SCADA) networks.

- **Fresh Water System** – Construction of a 3,000-barrel tank and water distribution pipelines for ancillary purposes, including fire protection, lavatories, showers, equipment cleaning, dust control, minor landscape irrigation, and also possibly for drinking water. No fresh water would be used to generate steam for the Project.
- **Support Infrastructure** – Construction of an office building, a multipurpose building, a warehouse and maintenance building, a facility control building, and an onsite septic system.
- **Tanker Truck Transport** – Importation of light crude via new Compressed Natural Gas (CNG) trucks for blending from Aera's Belridge Producing Complex in the South Belridge Oil Field near Bakersfield (140.4 miles), and exportation of produced, blended crude oil back to Aera's Belridge Producing Complex.
- **Conservation Easement** – A permanent Conservation Easement, located in an area east of Long Canyon Road, where no surface oil production activities are proposed. The Conservation Easement would be used to provide mitigation for unavoidable Project impacts, and to provide conservation, educational, and recreational opportunities for the Santa Barbara County community.

SoCalGas Natural Gas Pipeline

- **Natural Gas Pipeline** – Construction of a new, approximately 14-mile, 8-inch natural gas pipeline and associated facilities, which include above ground valves, underground valves, and a metering station at the pipeline terminus.

PG&E Electrical Power Line Interconnection

- **Electrical Power Line Interconnection** – Construction of a new, approximately 0.3-mile 115 kilovolt (kV) power line to interconnect Pacific Gas and Electric Company's (PG&E's) Sisquoc–Santa Ynez 115 kV power line to a new Aera-owned substation, located within the central processing facility.

This section is organized as follows:

- *Section 2.2*, Project Location, describes the Project's location and surrounding land uses.
- *Section 2.3,* Project Objectives, presents Aera's stated Project objectives.
- *Section 2.4*, Background and Historic Operations, presents the historic oil and gas operations at the Project site.
- *Section 2.5*, Proposed Project Components, describes each of the proposed components of the Project that are listed above.
- *Section 2.6*, Construction, describes the construction and operation of each of these Project components.
- *Section 2.7,* Produced Oil Transport, presents the proposed trucking of light and blended produced crude from/to Aera's Belridge facility near Bakersfield, CA.
- *Section 2.8*, Operation, Maintenance, and Abandonment, describes Project operations and maintenance, include well workovers and replacement.
- *Section 2.9*, Decommissioning, describes decommissioning of the Project site facilities and wells at the end of the Project (30 to 50 years or more).
- *Section 2.10*, Applicant Proposed Avoidance and Minimization Measures, discusses measures proposed by Aera, SoCalGas, and PG&E to minimize the Project's environmental impacts.
- *Section 2.11*, Alternatives, describes alternatives to the proposed Project, including the No Project Alternative.
- *Section 2.12*, References, lists references cited within the section.

2.2 Project Location

2.2.1 Oil and Gas Field

The site for the East Cat Canyon Oil Field Redevelopment Project (Project) is located in the eastern area of the Cat Canyon Oil Field, which has been used for oil production purposes for more than 100 years. The Cat Canyon Oil Field is a State-designated oil field with boundaries defined by the California Department of Conservation, Division of Oil, Gas and Geothermal Resources (DOGGR), which covers over 26,440 acres and includes nearly 1,600 active and idle oil wells. The application involves numerous properties located along Cat Canyon Road and Long Canyon Road in the County's Fifth Supervisorial District, near the communities of Garey and Sisquoc. The Project site consists predominantly of rolling hills with some steep slopes. Figure 2-1 (Project Location and Overview) shows where the Project site is located within Santa Barbara County, and Figure 2-2 (Oil Field Boundaries) illustrates its location within an existing oil field.

The Project site is located within the Agricultural II (AG-II-100) and Agricultural Commercial (AC) zone districts. In accordance with the County Land Use and Development Code Table 2-1 and Section 35.5, oil and gas extraction is an allowed use within the AG-II and AC zone districts. No change in existing land use designation and/or zone district is proposed as part of the Project.

Land uses surrounding the Project site include oil and gas production; and grazing to the north, south, and west; a winery tasting room to the northeast; and residential development on large agricultural parcels primarily to the north and south-southeast, as shown on Figure 2-3 (Adjacent Land Uses). The western portion of the Project site is located adjacent to the existing ERG Resources, LLC Cat Canyon development site (active field). In addition, Greka produces oil from the adjacent Bell lease. The Project site currently supports office/warehouse buildings, 178 abandoned oil wells, four producing ERG wells, four non-producing Aera test wells, a system of graded access roads and wells pads, former facility locations, a permitted beneficial reuse site, fresh groundwater wells, firewater and grazing tanks, and cattle grazing.

The Project site consists of 2,112 acres, of which 1,553 acres are combined fee (both surface and mineral ownership) and 555 acres are divided interests (various surface owners and shared mineral ownership). Approximately 4 acres of Project access roadways and entrances may be located on two adjacent parcels that are located outside of the Project site boundaries and are not controlled by Aera (neither surface nor mineral ownership). These two parcels, which are not included in Table 2-1, may be used for the Project, subject to the execution of access agreements with the property owners.

In addition, there are three parcels (APNs 129-210-017, 101-050-42 and 101-050-042) that are currently under Agricultural Preserve Contract (No. 77AP019). The proposed oil and gas production activities on the subject parcels would be limited to fresh water supply wells to be used for domestic, conservation, and agricultural use, as well as a conservation area for oak tree replanting and habitat enhancement.

Table 2-1. Project Leases and Assessor's Parcel Numbers

Lease Name	Acreage	Assessor's Parcel No. (APN)
Bonetti	240	101-040-006
Field Fee	159	101-070-007
Fleisher	244	101-040-005* 101-040-011*
McCroskey Fee	189	101-050-042 (portion) 129-210-017
McNee	321	101-050-042 (portion)
R&G	155	101-040-019
Victory	716	101-040-014* 101-040-020 101-050-013 101-050-014
West	71	101-040-013*
Westco & Petan Fee	12	101-040-012*

Source: Aera, 2016
*Parcels to be combined as part of Aera's Tentative Tract Map application for the Project site.

The leases and assessor parcel numbers associated with the Project are presented in Table 2-1.

2.2.1.1 Vesting Tentative Tract Map

As part of the Project, under a Vesting Tentative Tract Map (TT14813) and in compliance with County Code Chapter 21, the Applicant proposes to reconfigure 11 existing parcels with a total acreage of 1614-acres, into 12 new lots with an average lot size of 140-acres. A proposed 30-foot reciprocal easement would create a private access road extending from Long Canyon Road (public) across proposed Lots 5, 6, 7, 8, 9, 10, 11 and 12 (Figure 2-3). The existing parcels and reconfigured lots under the proposed Tentative Tract Map are presented in Table 2-2 and illustrated on Figure 2-3. The proposed conservation easement would be located within Lots 1 and 2. The existing parcels under a Williamson Act contract (Agricultural Preserve Contract No. 77AP019) are proposed to be reconfigured as Lots 1 and 3 with a net increase of approximately 10-acres for a total of 517 acres under contract. Aera is requesting the County of Santa Barbara's approval to reconfigure the Project site parcels consistent with the Subdivision Map Act regulations.

Table 2-2. Existing Parcels and Proposed Lots

	Existing Parcels		Proposed Lots	
	APN	Acreage	Lot No.	Acreage
1	101-050-042	422	Lot 1	337
2	101-050-013	315	Lot 2	166
3	101-050-014	236	Lot 3	175
4	101-070-007	161	Lot 4	169
5	101-040-020	80	Lot 5	121
6	101-040-019	155	Lot 6	105
7	101-040-014	79	Lot 7	116
8	101-040-013	70	Lot 8	167
9	101-040-012	12	Lot 9	105
10	101-040-011	162	Lot 10	164
11	101-040-005	84	Lot 11	119
			Lot 12	125

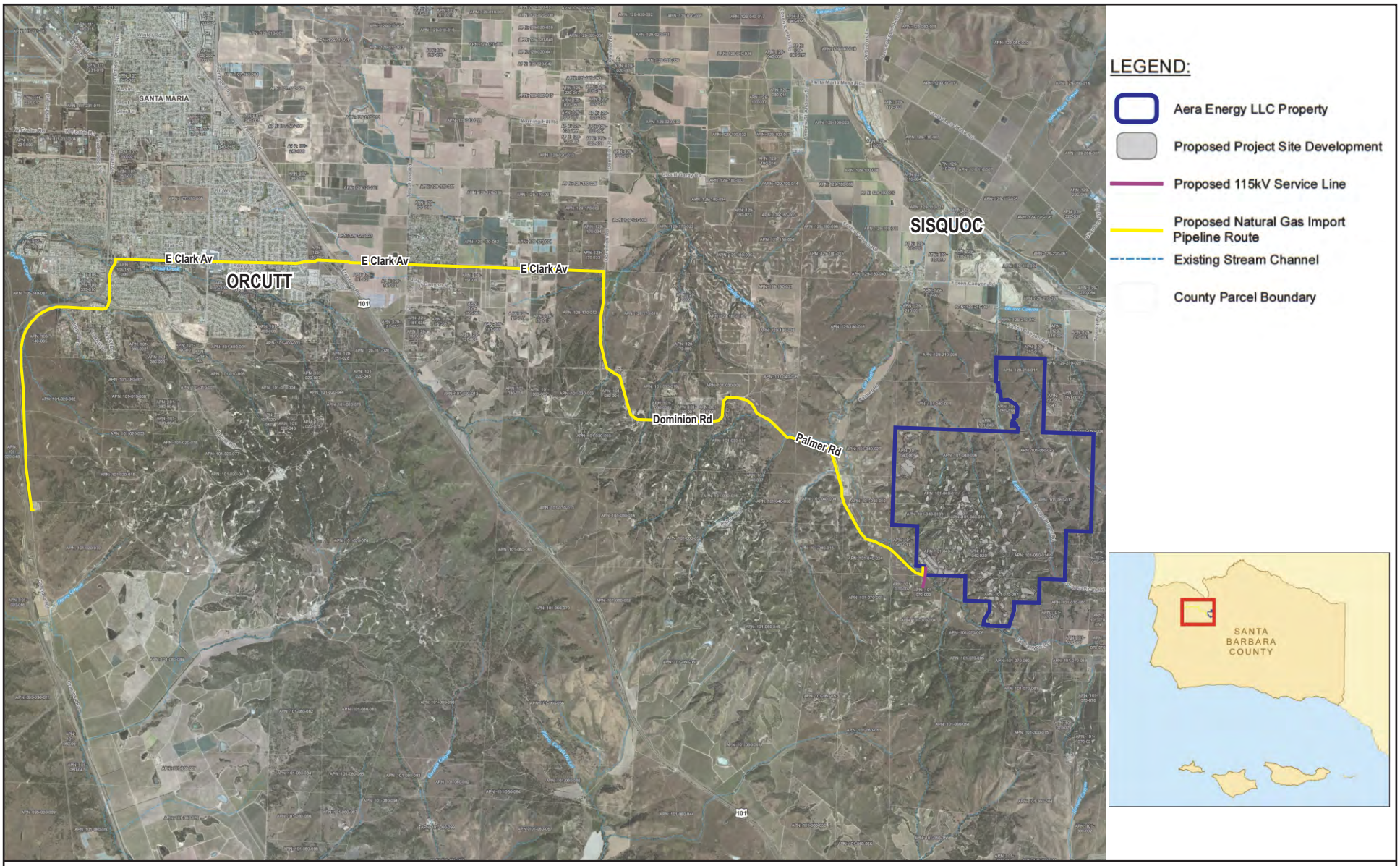
The following is the Project location description of the Natural Gas Pipeline and Electrical Power Line Interconnection Project components:

2.2.2 Natural Gas Pipeline

The Project includes a new 14-mile, 8-inch natural gas pipeline to deliver natural gas fuel at a sufficient rate to meet the needs for thermal enhanced oil recovery steam generation. The proposed natural gas pipeline and associated facilities would originate at the existing Southern California Gas (SoCalGas) Line 1010 at Divide Station, located along Graciosa Road, and would terminate at Aera's proposed central processing facility located in the southwest corner of the Project site (see Figure 2-10, Proposed Natural Gas Import Pipeline Route). The natural gas pipeline would be primarily installed in the existing public utility corridor within the public right-of-way, under existing road pavement. Approximately three preliminary staging areas would be required to store pipe and provide a location for the contractor to stage equipment and materials during construction.

2.2.3 Electrical Power Line Interconnection

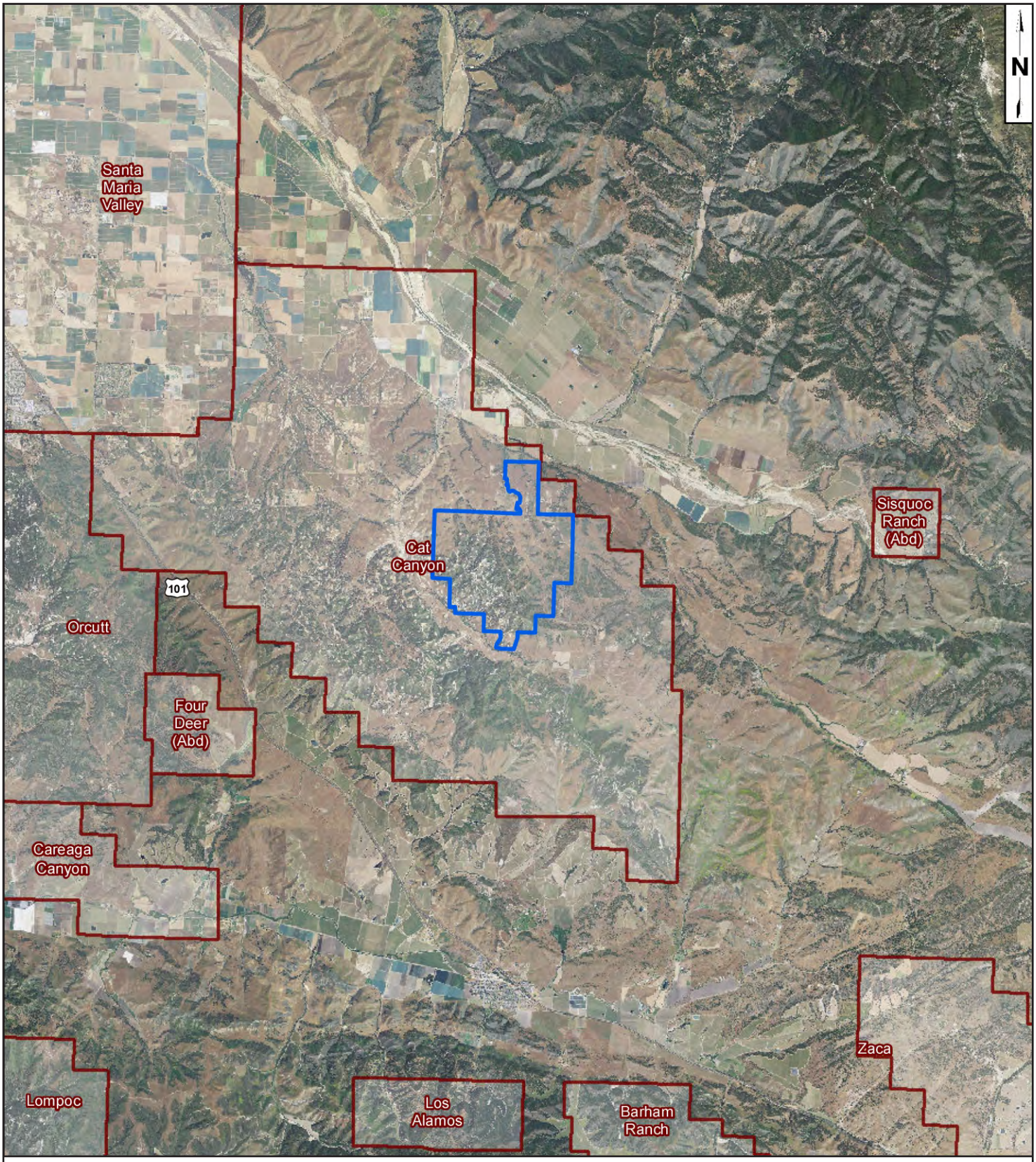
The proposed electrical Pacific Gas and Electric (PG&E) power line interconnection would include an approximate 0.3-mile overhead power line interconnect from PG&E's existing Sisquoc–Santa Ynez 115 kV power line to the new onsite Aera-owned 115/12.47 kV substation (see Figure 2-11, Electrical Power Line Interconnection).



Source: Aera, 2016.

Figure 2-1

Project Location and Overview



Source: Aera, 2016.

LEGEND:

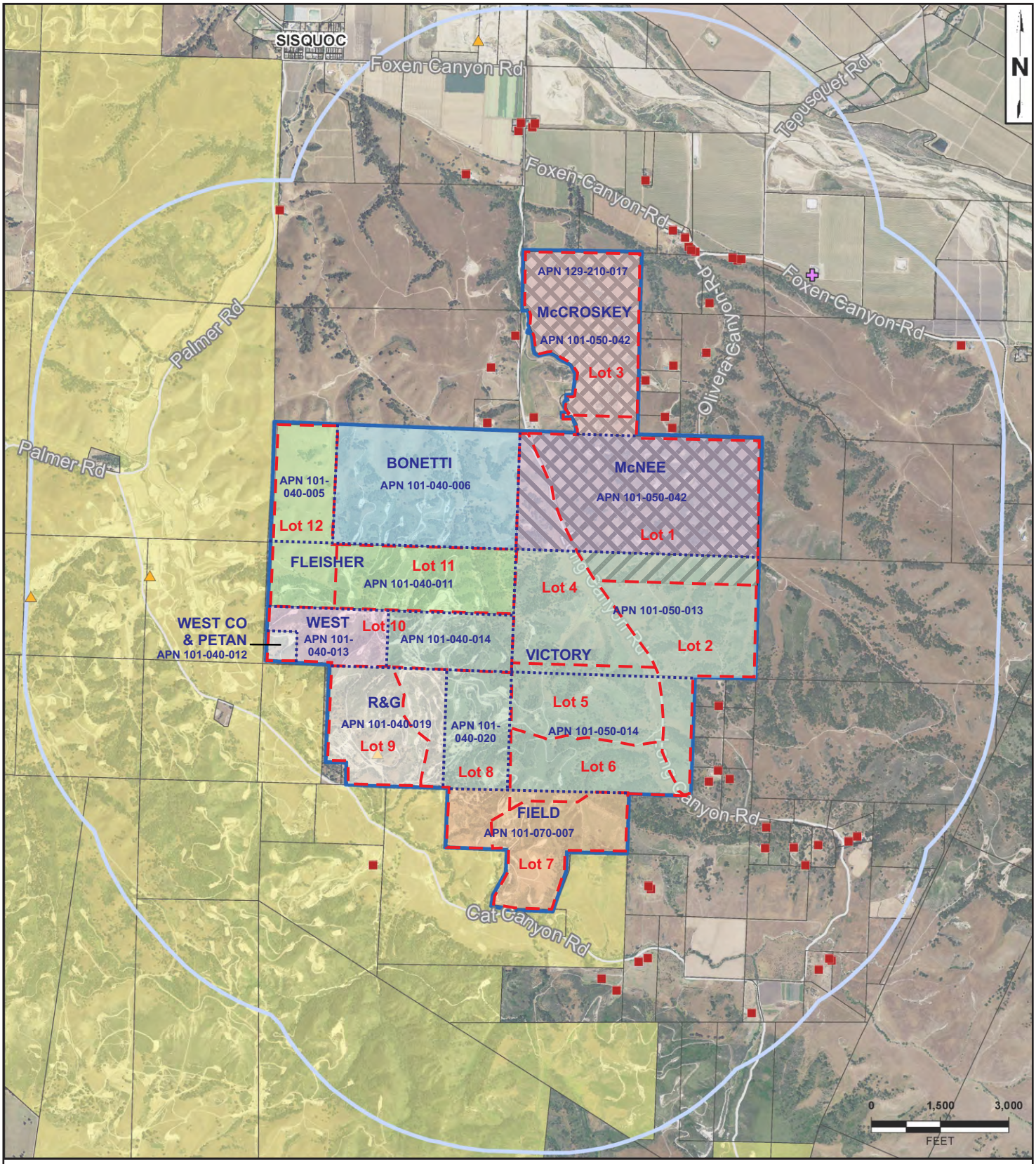
Aera Energy LLC Property

Oil Field Boundary

0 1 2
MILES

Figure 2-2

Oil Field Boundaries



Source: Aera, 2016.

- Residence
- Office
- Winery Tasting Room
- Aera Energy LLC Property
- 1mi Buffer of Property Boundary
- Assessor Parcel Boundary
- Parcel with Existing Active Oil and Gas Opperations
- APN
- Lot
- Existing Agricultural Preserve (507 acres)
- Proposed Agricultural Preserve (517 acres)

Figure 2-3

Vested Tentative Map Revisions & Adjacent Land Uses

2.3 Project Objectives

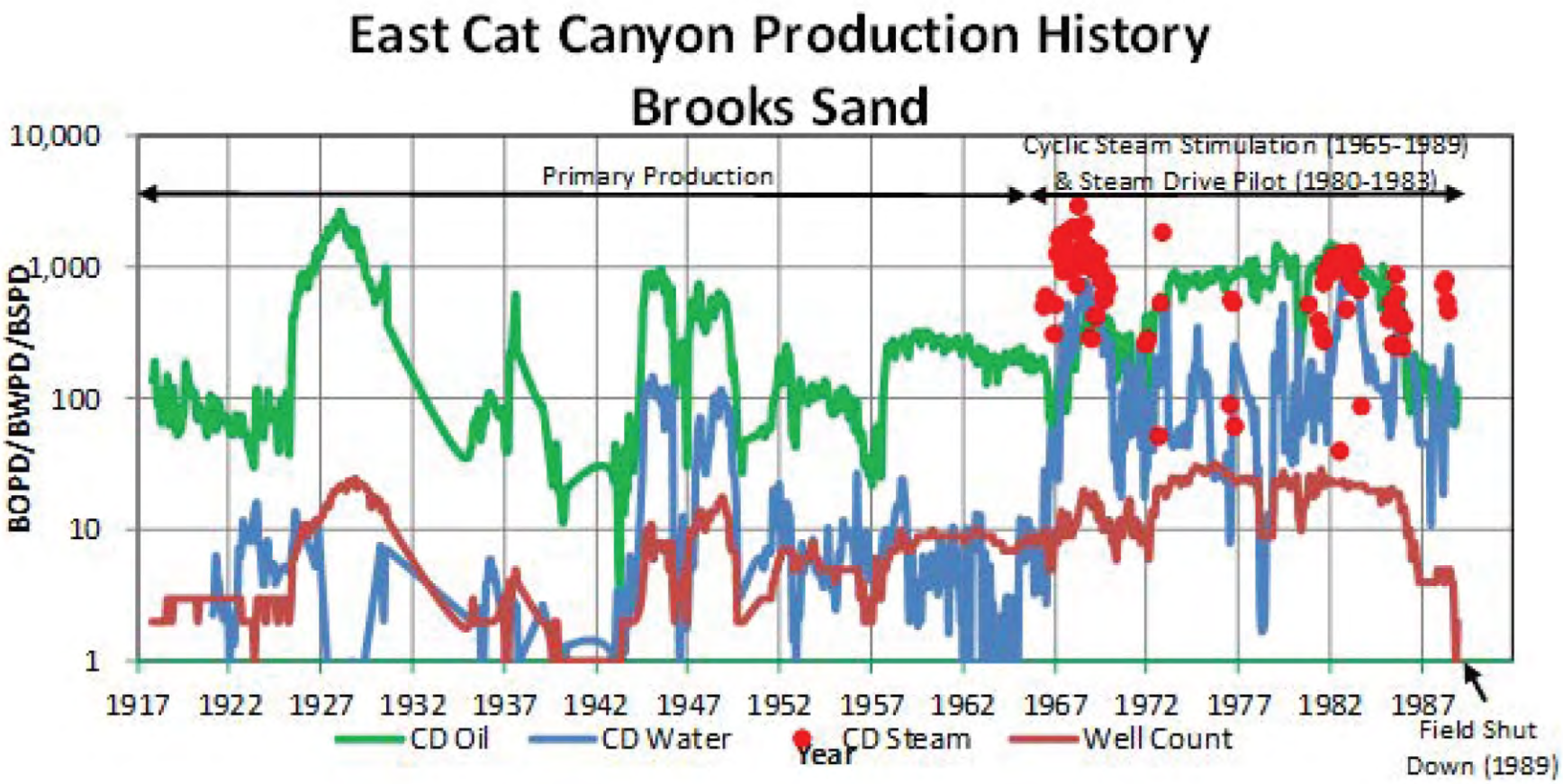
Pursuant to Section 15124(b) of the California Environmental Quality Act (CEQA) Guidelines, the description of the proposed Project is to contain "a clearly written statement of objectives" that would aid the lead agency in developing a reasonable range of alternatives to evaluate in the Environmental Impact Report (EIR) and would aid decision makers in preparing findings and, if necessary, a statement of overriding considerations. The County is the lead CEQA agency preparing the EIR, considering the EIR for certification, and presenting the Project to the County Planning Commission for consideration of approval.

The Applicant's stated Project Objectives are as follows:

1. Safely and economically produce crude oil while protecting the environment and creating new jobs, new tax revenue, community investment, and other benefits for Santa Barbara County;
2. Re-establish oil production at the East Cat Canyon Oil Field at a forecasted level of up to 10,000 barrels of oil per day in this existing oil field by drilling and operating oil/gas production wells, steam injection wells, observation wells, source water wells, water injection wells, fresh groundwater wells, production gathering systems, a central processing facility, steam generation and distribution systems, and related ancillary equipment;
3. Obtain the required natural gas and electric utility services to economically operate the Project site;
4. Protect human health and the environment by complying with all applicable laws and regulations and by implementing Aera's System of Operating Excellence;
5. Economically and reliably transport produced crude to a competitive crude market destination having economic viability over the life of the Project;
6. Use existing well pads, roads, and other infrastructure where practical and feasible to minimize land disturbance;
7. Use non-potable brackish water as the primary source of water for steam generation to minimize use of potable groundwater; and
8. Reduce California's reliance on imported oil by providing in-state supplies.

2.4 Background and Historic Operations

The Cat Canyon Oil Field contains approximately 1,600 active and idle oil wells. Development of the west and east areas of the Cat Canyon Oil Field expanded rapidly between 1909 and 1919. Figure 2-4 (Historical Timeline and Production) shows that the development of the East Area of the Cat Canyon Oil Field started in 1917 and was in production for 72 years. A thermal enhanced oil recovery operation (cyclic steam injection) occurred from 1965 through 1989 and a thermal pilot operation (steam drive) was conducted from 1980 through 1983. Cumulative oil production at the Project site from 1917 until the late 1980s was approximately 10 million barrels of oil from 100 wells producing initially by primary and later with thermal recovery methods. Intermittent production activities at the east area of the Cat Canyon Oil Field were conducted until 1989, when the oil field was shut down due to economics at that time.



Source: Aera, 2016.

Figure 2-4

Historical Timeline and Production

As shown in Figure 2-5 (DOGGR Well Map), 178 wells were abandoned per DOGGR regulations and nearly all of the facilities were removed by 2003. A 2017 review of DOGGR well records show 178 of the Project site oil wells as being plugged and abandoned with official DOGGR Record of Abandonment documents; however, six wells, drilled by other previous operators, were not found in the DOGGR well database. These six wells are: Victory 17, Field Fee 1, 2, 6, 6A, and Victory 3.[1] A map showing the locations of the six wells is included in Appendix B (Project Description Supporting Information). For the purposes of this EIR, it is assumed as a worst-case scenario that all six of the wells would have to be re-abandoned. Associated access roads and well pads remain intact.

2.5 Proposed Project Components

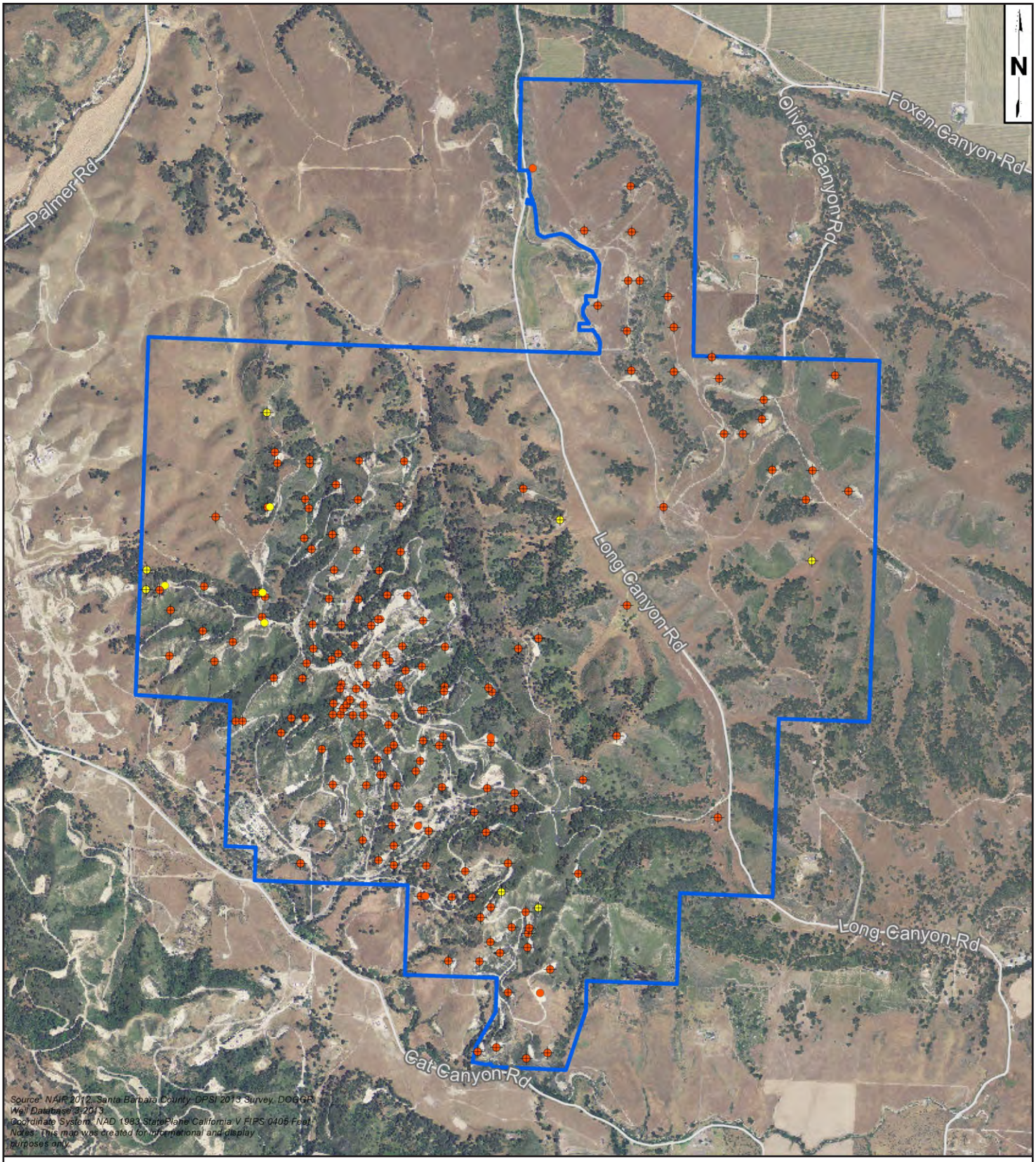
The Project would re-establish oil production in an existing oil field by implementing a thermal enhanced oil recovery process. Project plans include construction and use of existing well pads for a total of 72 well pads, construction and use of existing roads for a total of over 9 miles of field access roads, and drilling of up to 296 wells. Planned wells include oil/gas production wells, steam injection wells, observation wells, non-potable water production wells, water injection wells, and fresh groundwater wells. No hydraulic fracturing would occur. The proposed Project also includes construction of new processing facilities, field systems, utility connections and delivery lines, and the transport of produced oil by truck. Each of the components are described in the following subsections and are depicted on Figure 2-6 (Project Overview and Phasing). Construction and operation of the Project components described in this section are discussed in Section 2.6 (Construction) and Section 2.8 (Oil Field Operation, Maintenance, and Abandonment).

2.5.1 Thermal Oil Recovery Process

The Project proposes to inject steam into the Brooks sand (Brooks reservoir), which is a lower portion of the Sisquoc Formation, to thermally enhance oil recovery pursuant to DOGGR regulations. By heating the oil with steam, viscosity would be reduced, allowing the oil to more readily flow out of the reservoir, into the wells, and into the surface pipelines and processing areas. Although there are many variations, the two main thermal methods proposed to be applied to the Brooks reservoir are:

- *Cyclic Steam Injection* – Cyclic steam injection consists of three stages: injection, soaking, and production (see Figure 2-7, Cyclic Steam Injection). Steam is first injected into a well for a prescribed amount of time to heat the oil in the surrounding reservoir to a temperature at which it more readily flows. After a pre-determined amount of steam has been injected, the steam is usually left to “soak” for some time (typically a few days) to distribute the heat. The oil is then produced out of the same well using electric pumps. As the oil cools down, production decreases until it reaches an economically determined level, when the steaming cycle is repeated. The produced fluids consist of produced crude oil, connate water (the naturally occurring water in the pore space before injection begins), small amounts of naturally occurring reservoir gas, condensed water from injection, and sometimes steam. The produced fluids travel from the well to a gathering pipeline to the central processing facility where the crude is processed to meet sales specifications, the gas is treated and reused for process heat, and the water is cleaned and recycled to produce steam.

[1] As part of its permit application to DOGGR, Aera is currently performing an Area of Review (AOR) study of all historical and existing wells within the radius of influence of the Project. Based on the results, DOGGR may require that existing wells within the injection area of influence to be repaired, plugged, and abandoned, or re-abandoned as necessary. Aera identified the Victory 17 well as requiring abandonment. Aera has currently classified the remaining five wells without abandonment records (Field Fee 1, 2, 6, 6A & Victory 3) as “needing to be evaluated due to missing data.” As part of its evaluation process, Aera will search for missing data, inspect the well locations, and report findings to DOGGR in the AOR Submittal. DOGGR will determine what additional work Aera will be required to perform on those wells in order to assure ground water quality protection (Aera, 2017).



Source: Aera, 2016.

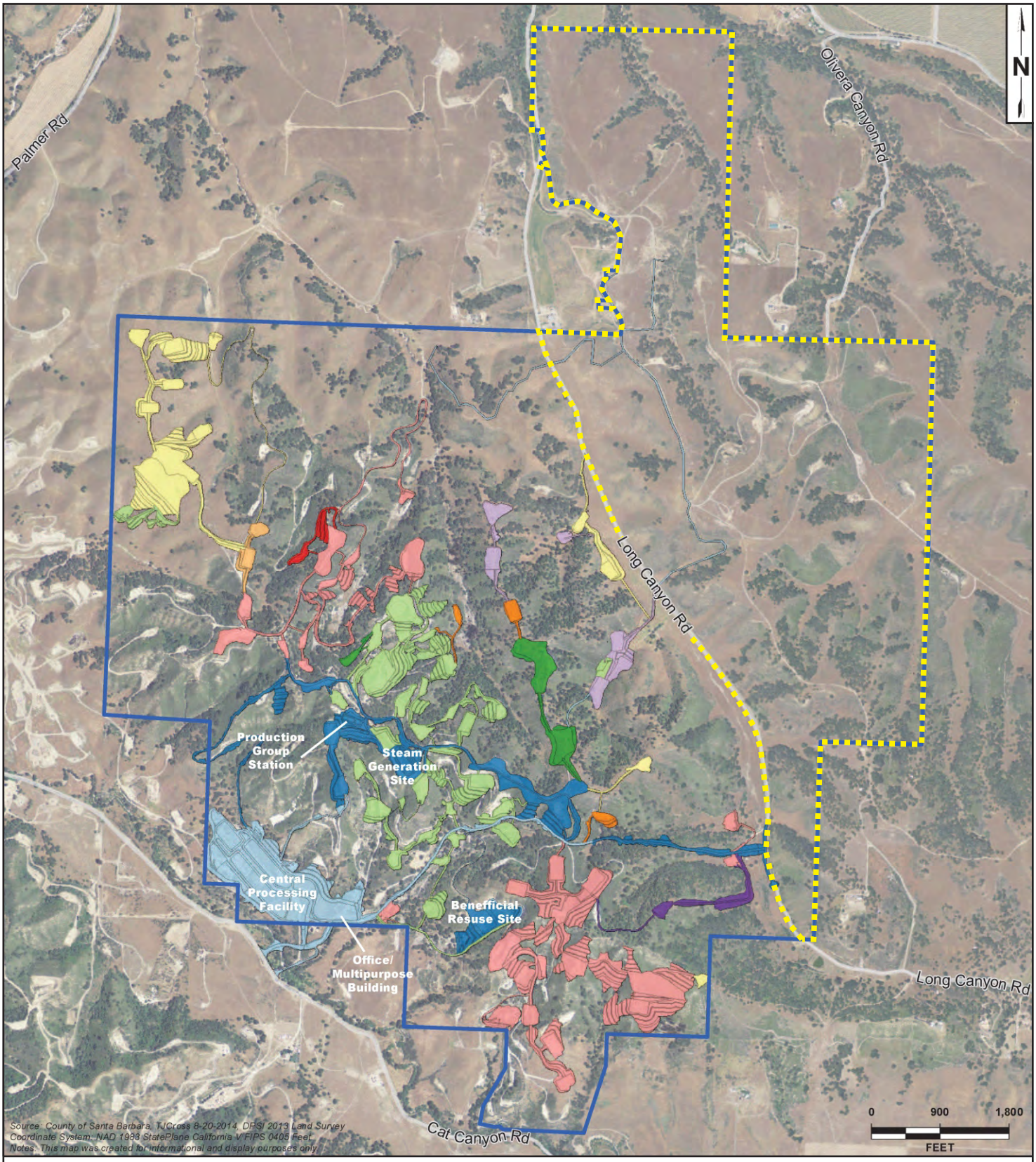
0 1,000 2,000
FEET

LEGEND:

- Aera Energy LLC Property
- Aera Energy LLC Abandoned / Inactive Well
- Aera Energy LLC Active Test Well
- Other Operator Abandoned / Inactive Well
- Other Operator Active Well

Figure 2-5

DOGGR Well Map



Source: Aera, 2016.

Aera Energy LLC Property

Project Construction*

Year 1

Year 2

Year 3

Year 4

Year 8

Year 10

Year 13

Year 14

Year 15

Year 18

Year 19

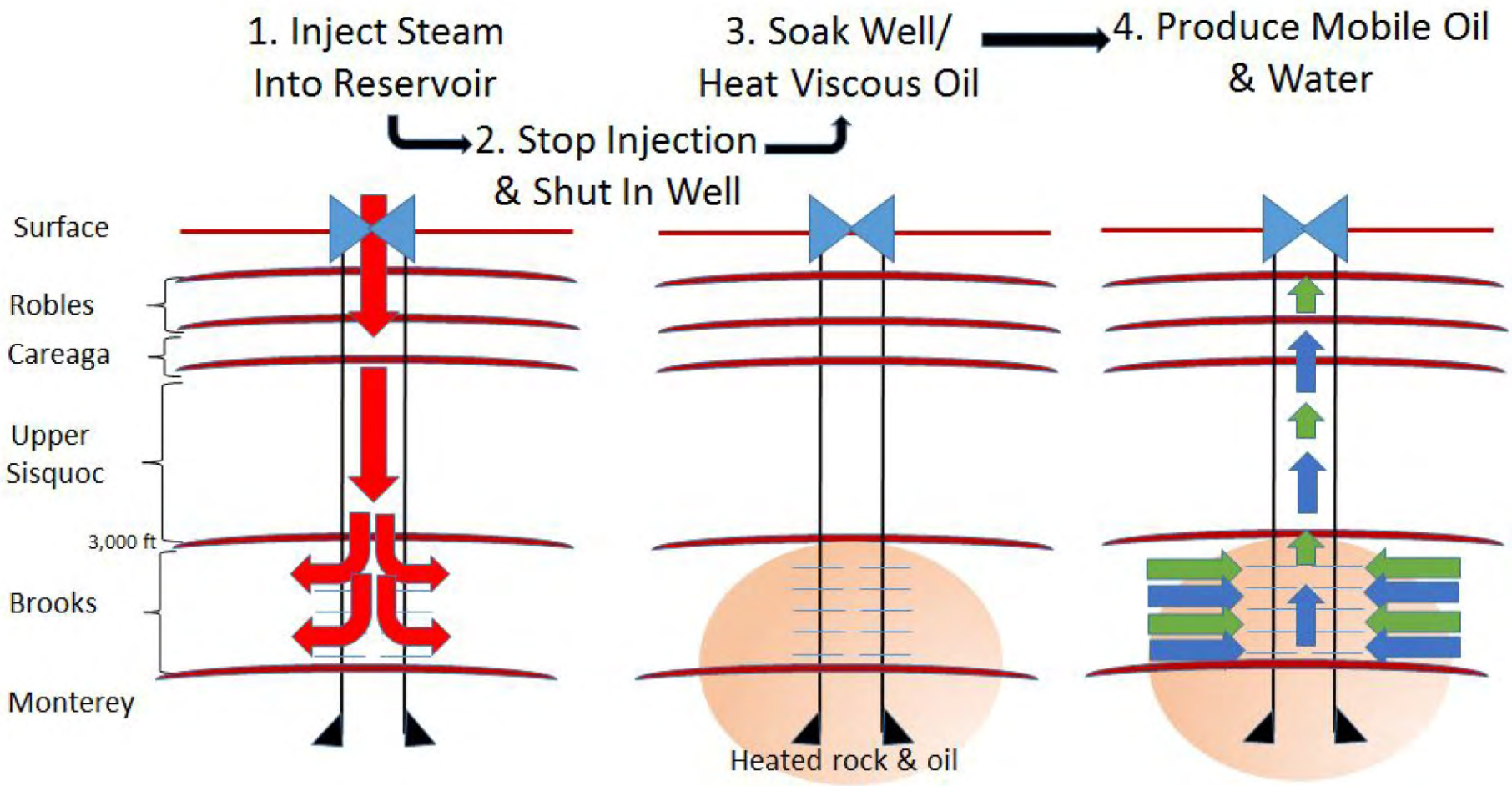
Proposed Project Conservation Easement

*Anticipated start dates

Construction of the 115 kV electrical transmission line is anticipate to occur in year 1 and construction of the natural gas pipeline is anticipated to occur in year 2.

Figure 2-6

Project Overview and Phasing



Source: Aera, 2016.

Figure 2-7

Cyclic Steam Injection

- *Pattern Steam Flood* – In a pattern steam flood, steam is injected into a well specifically designed for injection only (see Figure 2-8, Pattern Steam Flood). The crude oil is heated in the reservoir and flows to a production well by pressure differential and/or gravity drainage. The production well is cyclic steamed first in order to increase voidage in the vicinity of the production well and therefore establish a pressure differential between the injection well and production well. Continuous steam injection from the injection well commences at the same time as cyclic steaming starts in the production well. From time to time, an established production well may still be cyclic steamed to provide a more even heat distribution between the production and injection wells.

While crude oil would be recovered mostly by steamflooding at the Project site, the producer wells and possibly some injector wells would be initially cyclic steamed to decrease the reservoir pressure. Once the desired pressure conditions are established, steam would be injected only in the injectors and production would be through the producers, like in a typical steamflood. Given the geologic characteristics of the Brooks reservoir, no hydraulic fracturing is necessary or proposed as part of the Project.

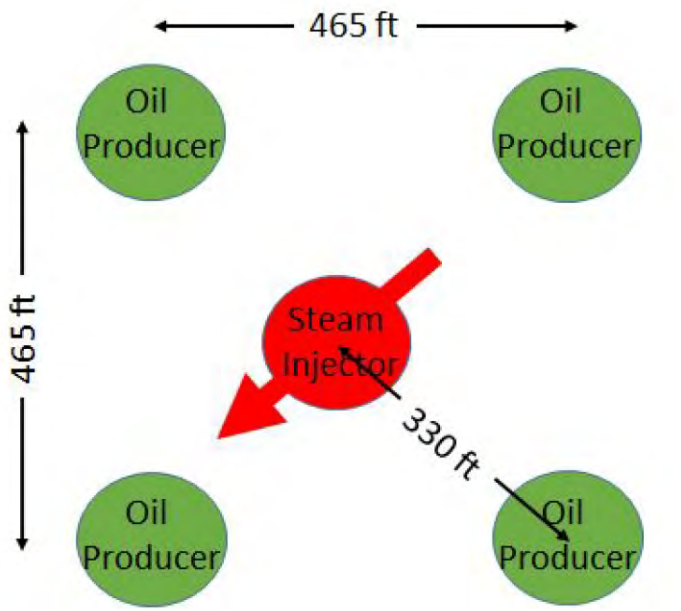
2.5.2 Subsurface – Wells

Approximately 72 well pad locations are proposed, ranging in size from approximately 0.37 acres for lower density well sites to 7.04 acres for pads encompassing multiple wells. A grid is established between production and injection wells to maximize the effectiveness of the steam. Therefore, most of the well pads would service a five-spot flood pattern unit that on average is equivalent to one injection well and one-quarter of each of our production wells (see Figure 2-8, Pattern Steam Flood). As shown in Table 2-3 and described below, six different well types are proposed to be drilled and maintained as part of the Project. Phasing of well development is shown on Figure 2-6 (Project Overview and Phasing) and further detailed by year in Table 2-4 (Number of Wells Per Year).

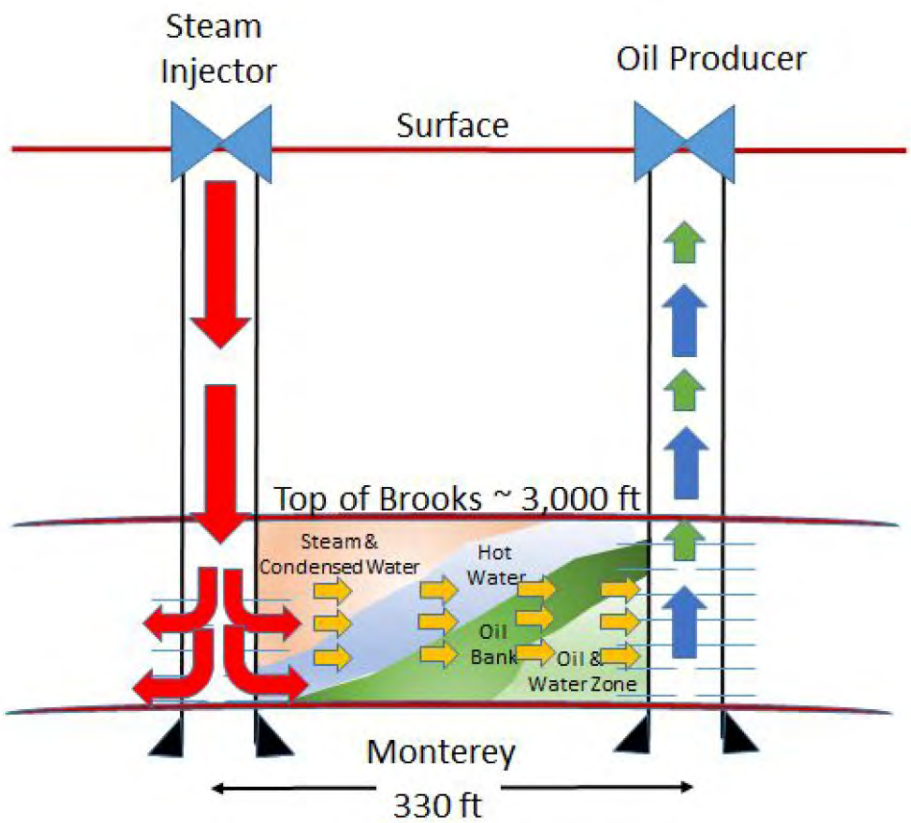
- **Oil Production Wells** – Production wells would be drilled and completed in the Brooks reservoir at a depth of approximately 3,000 feet using truck mounted, portable engine mud and concrete pumps. Electric pumps would be required to bring produced oil, water, and gas to the surface. Gas and water vapor would also be produced through the well casing and tied into flow lines. The potential need for a casing vapor recovery system would be assessed in the future on an individual well basis. Although the Project is designed as a continuous steam flood, production wells would be cyclically steamed to initiate production and occasionally thereafter following well maintenance activities. No hydraulic fracturing is proposed.

Although there are 178 abandoned wells that currently exist at the Project site, these wells are not available for Project use. Decommissioning of those wells included, among other things, filling the wellbore with cement so it cannot be used again. However, the well pads surrounding the abandoned wells would be reused to the extent feasible.

- **Steam Injection Wells** – Steam injection wells would be drilled and completed in the Brooks reservoir at a depth of approximately 3,000 feet. Steam injection surface equipment would consist of flow lines and measurement and control devices for pressure and flow. High pressure steam would be distributed to well pads from the steam generation site. Steam would be separately measured and controlled for each steam injection well. After drilling, some injection wells may initially be cyclically steamed and produced, prior to constant steam injection.
- **Observation Wells** – Observation wells would be drilled and completed in the Brooks reservoir at a depth of approximately 3,000 feet. Observation wells neither produce nor inject fluids. Temperature sensing devices are inserted into the wellbore to monitor steam movement and distribution in the formation. A total of 24 observation wells are anticipated, of which 23 will be drilled during Phase I to monitor steam movement and distribution in the formation.



5-Acres Inverted 5-Spot Pattern Plan View



Cross-Section

Source: Aera, 2016.

Figure 2-8

Pattern Steam Flood

Table 2-3. Project Well Types

Well Type	Phase I Wells	Phase II Wells	Total Wells
Oil Production – to produce oil, as well as produced water for steam	35	106	141
Steam Injection	31	76	107
Observation – to monitor steam movement and distribution in the formation	23	1	24
Upper Sisquoc Water Production – to produce additional non-potable brackish water for steam	6	1	7
Upper Sisquoc Water Injection – to re-inject produced water residual brine back into the reservoir	10	4	14
Fresh Water – to produce water for fire protection, minor landscape irrigation, other auxiliary uses, and possibly for human consumption	3	0	3
TOTAL	**108**	**188**	**296**

Source: Aera, 2016.

Table 2-4. Number of Wells Per Year

	Phase 1				Phase 2								
Well Type	**Year 1**	**Year 3**	**Year 4**	**Year 5**	**Year 8**	**Year 10**	**Year 13**	**Year 14**	**Year 15**	**Year 16**	**Year 18**	**Year 19**	**Total**
Production	—	35	—	—	41	5	5	11	8	6	6	24	141
Steam injection	—	26	5	—	40	4	1	1	7	5	3	15	107
Observation	—	23	—	—	1	—	—	—	—	—	—	—	24
Brackish water	—	3	—	3	1	—	—	—	—	—	—	—	7
Disposal	—	8	—	2	1	—	—	3	—	—	—	—	14
Fresh water	3	—	—	—	—	—	—	—	—	—	—	—	3
TOTAL	**3**	**95**	**5**	**5**	**84**	**9**	**6**	**15**	**15**	**11**	**9**	**39**	**296**

Source: Aera, 2017.
Notes: Does not include replacement wells, which are projected to be 30 over the course of the Project life, approximately 1 per year of any type. No new wells are proposed in Years 2, 6, 7, 9, 11, 12, 17, 20 and 21.

- **Steam Water Production and Recycled Water/Brine Injection Wells** – Steam water production and recycled water/brine injection wells would be drilled and completed in the Upper Sisquoc Formation sands reservoir at a depth of approximately 2,000 feet. Electric submersible pumps would be used for the Upper Sisquoc water production wells and the produced water would be processed for steam injection into the Brooks reservoir. The surface equipment would consist of a wellhead, flow measurement device, flow line, and a motor control. Upper Sisquoc water injection wells would be equipped with a wellhead, a flow pressure/control device, and a flow line. Injection wells would be used for the residual brine (i.e., salts and minerals) that results from produced water softening and processing for steam injection. All residual brine from water treatment would be added to the produced water and then re-injected into the Upper Sisquoc Formation sands reservoir at the same depths. Water quality tests would be regularly performed on produced water and water treatment brine prior to injection/disposal. These tests would typically include geochemical, Total Dissolved Solids (TDS), Total Suspended Solids (TSS), and Millipore analyses.
- **Fresh Groundwater Wells** – Fresh groundwater for the Project would come from source wells completed in the Careaga and the Paso Robles Formations within the Santa Maria Ground Water Basin and

would be brought to the surface using electric pumps. These fresh water aquifers are located at approximately 600 feet below the surface, approximately 2,400 feet above the Brooks reservoir (the oil production zone, which is approximately 3,000 feet below the surface, as shown in Figure 2-16 [Generalized Geologic Cross Section]) and separated from it by the thick, regionally extensive, impermeable Foxen hydrogeological barrier. Several water wells are currently in place at the Project site; however, not all are active. Current plans include the re-drilling or recompletion of one existing fresh water well (McCroskey-WS12), as well as drilling of up to two additional freshwater wells. The two additional water wells would likely be placed somewhere within the proposed central process facility area where disturbance impacts would be analyzed as part of the Project. Project water usage is discussed in Section 2.5.10 (Water Use).

2.5.3 Processing Facilities

The majority of the Project's fluid processing would take place within a single complex called the central processing facility, which would be located on the southwestern portion of the Project site (see Figure 2-6, Project Overview and Phasing). As part of the fluid processing system, produced fluids would be gathered from production well pads. Gas would be separated from produced fluids at the production group station. From the group station, liquids would flow to the central processing facility for oil cleaning, water cleaning, water softening, oil storage, and oil sales. Gas from the production group station would flow to the steam generator for treatment and use as fuel for steam generation. From the central processing facility, softened produced water (from oil production wells) and softened brackish water (from Upper Sisquoc Formation sands water production wells) would be sent to the steam generation site where steam generators would create a wet, saturated steam. The steam would then be distributed back to well pads for injection.

The proposed Project would include construction of all new processing and steam generation facilities, which are described in more detail below.

2.5.3.1 Central Processing Facility

The central processing facility would include the following components:

- **Oil Cleaning Plant**. The oil cleaning plant would receive fluids from the production group station. The oil cleaning plant would consist of two equipment "trains";[2] one train would be constructed during Phase I and the second would be added during Phase II. The primary function of the oil cleaning plant would be to remove water and solids from the produced crude, and blend the produced crude with light crude oil for transport. Clean oil leaving the oil cleaning plant would be sent to storage tanks at the crude oil storage plant and separated produced water would be sent to water cleaning plant. Produced gas from the production group station and oil cleaning plant would be cooled and transferred to the produced gas treating plant
- **Crude Oil Storage.** The crude oil storage plant would receive and store clean blended crude from the oil cleaning plant. The primary function of the crude oil storage would be to store clean blended crude prior to sales.
- **Light Oil Storage.** Lighter, higher American Petroleum Institute Gravity crude oil would be handled in the light oil storage plant. The primary functions of the light oil storage are to receive and inventory light crude oil prior to blending with production in the oil cleaning plant.

[2] Equipment train is defined as a sequence of equipment through which a product is produced or processed.

- **Water Cleaning Plant.** The water cleaning plant would receive produced water from the oil cleaning plant and brackish water from the Upper Sisquoc water production gathering system. The plant's purpose would be to remove oil and solids from the water stream.
- **Water Softening Plant**. The water softening plant would receive filtered water from the water cleaning plant. The plant's primary purpose would be to soften filtered water for use in thermal enhanced oil recovery steam generation. Any excess filtered water would be diverted to Upper Sisquoc water injection wells.
- **Solids Concentrating Plant**. The solids concentrating plant would serve two purposes: (1) dewater solids collected in the oil cleaning plant, and (2) recover residual oil from various processes in the central processing facility. Residual oil and solids from various plant processes would be directed to dedicated tanks. Wet oil would be cleaned in a "residual oil" treater. Recovered clean oil would be transferred to crude oil storage. Wet solids would be dewatered with a centrifugal process and collected for beneficial reuse. Separated water would be returned to the water cleaning plant.
- **Produced Gas Treatment Plant**. The primary role of the produced gas treatment plant would be to remove sulfur from the produced gas. Treated, or 'sweetened', produced gas would be transferred to the produced gas steam generation plant for use to generate steam. In Phase I, a non-regenerative batch treatment system would be installed at the produced gas treatment plant. Batch systems are robust and can accommodate a wide range of gas rates and composition. The batch system would utilize a consumable iron media sold under numerous trade names. The media would require periodic replacement and disposition. Spent media would be directed to a suitably permitted non-hazardous waste management site (see Section 2.8.1.2, Waste Handling and Storage).

  Tank vapor recovery units would be installed within the central processing facility area to collect and compress low pressure tank vapors for treatment in the produced gas treatment plant. A Santa Barbara County Air Pollution Control District-permitted emergency flare would be provided to safely incinerate central processing facility vapors when the produced gas steam generator is unavailable. Solid sulfur by-products would either be sold for agricultural use or transported to an appropriately permitted disposal facility.
- **Electrical System.** Electrical power within the central processing facility would be distributed at 12 kV to several power distribution centers located throughout the Project site. Electrical power from the motor control centers would be run to the motor and lighting loads within the central processing facility.

  An emergency generator would allow vapor control and produced gas process equipment to continue to function in the event of an interruption to avoid gas release from atmospheric tanks or other vessels. An electrical substation rated as 115/12.47 kV would be installed within the central processing plant and is described in Section 2.6.6.2 (Construction Methodology for Electrical Power Line Interconnection).
- **Central Processing Facility Control Building.** The central processing facility would be supported by a control building. This building would provide operator control stations to monitor and remotely control process equipment.

2.5.3.2 Steam Generation Site

The steam generation site would consist of six once-through steam generators rated at 85 million BTUs/hour: three would be installed in Phase I, and three in Phase II. The steam generation site also would include a produced gas steam generator rated at 62.5 million BTUs/hour, and an emergency flare, both to

installed in Phase I, and a produced gas treating plant, portions of which would be installed in both phases. Also included are associated ancillary equipment to support the steam generators, such as high-pressure feedwater pumps and pre-heaters.

2.5.4 Field Systems

The proposed Project would include installation of a system of onsite intra-field gathering and distribution lines for various co-located services, including production gathering, steam distribution, source water gathering, reservoir maintenance distribution, fuel gas distribution, softened water transfer, separated produced gas and installation of intra-field electrical distribution and supervisory control and data acquisition (SCADA) networks.

The field gathering and distribution system has been designed to locate pipeline corridors primarily along roadways on raised pipe supports to minimize external corrosion. Construction sequencing/timing would be concurrent with the well pad and roadway development over a multi-year program throughout Phases I and II. Intra-field pipelines are depicted in Figure 2-9 (Intra-field Pipelines) and additional details are provided in Appendix B (Project Description Supporting Information).

2.5.4.1 Production Gathering System

Reservoir fluids would be pumped to the surface using artificial lift systems (i.e., electrical surface pumping units and/or submersible electric pumps). Once on the surface, produced fluids (and vapors) from individual wells would be routed through insulated carbon steel flowlines into a piping network connecting the well pads to the production group station and then to the central processing facility. The lines would range in size from 3 to 14 inches in diameter and would be raised off the ground by pipe supports to minimize external corrosion. Routing would be along access roads to take advantage of ground stability and to support spill prevention and containment.

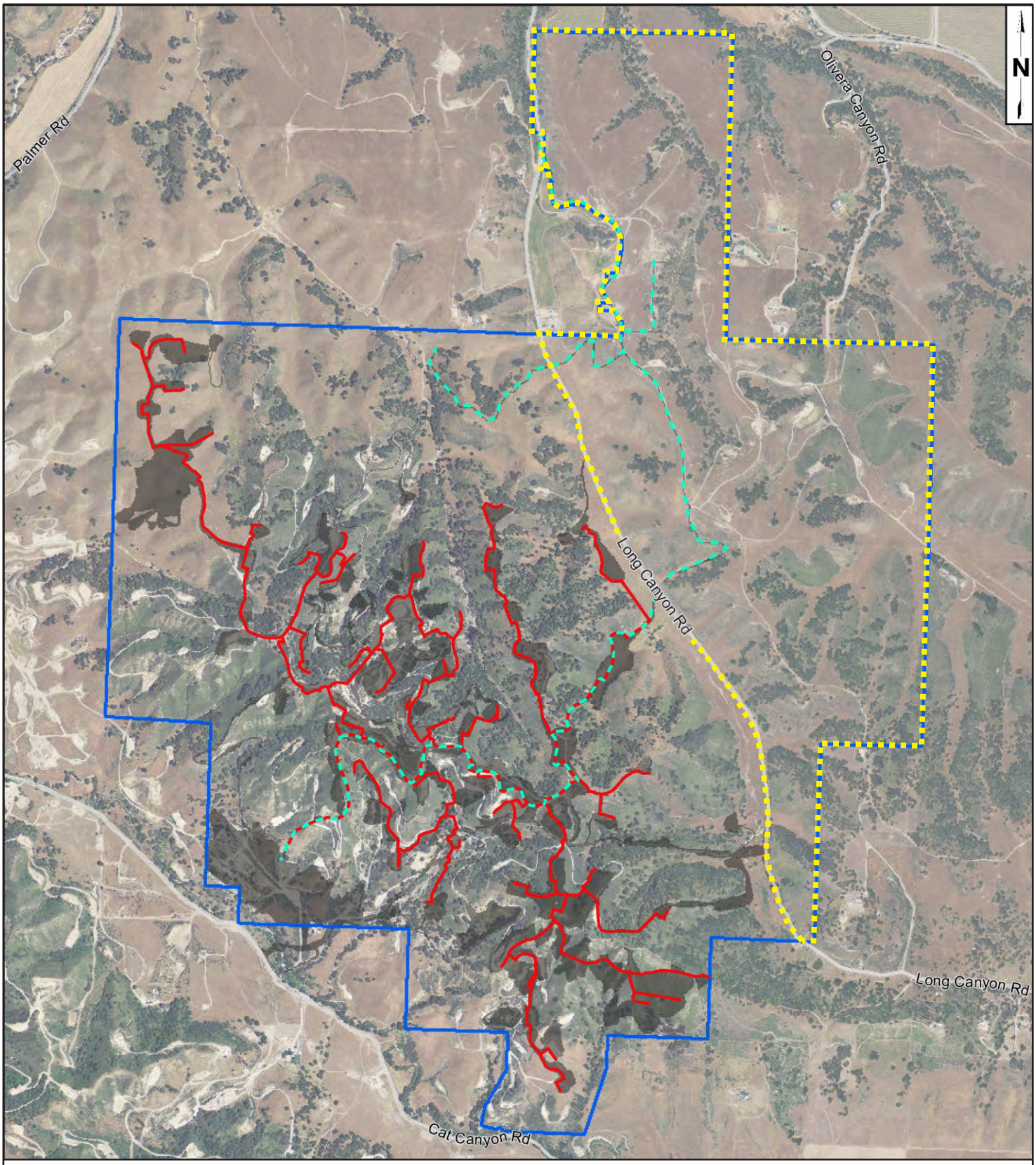
The production group station would receive produced fluids from the production gathering system, separates liquid and gas, and routes them to the central processing facility and steam generator site, respectively. The production group station would consist of two vessels, one installed in Phase I, and the second installed in Phase II.

2.5.4.2 Steam Distribution

The steam distribution system would be the conduit for transporting steam produced at the steam generation site to all wells receiving steam for subsurface injection. The steam distribution system starts at the steam generation site exit and terminates at the connection point for each well's flowline (injection line). Each well requiring steam injection would be connected to the distribution system with a steam injection measurement skid which would monitor, measure, and control steam injection pressure and volume. The steam lines would be constructed of insulated carbon steel in sizes ranging from 3 to 14 inches in diameter. The lines would be routed along access roads on raised pipe supports to minimize external corrosion.

2.5.4.3 Upper Sisquoc Water Gathering

Produced water wells completed in the Upper Sisquoc Formation would be used to provide initial (brackish) water for steam generation and to supplement the primary supply of produced water from the Brooks reservoir as needed during the life of the Project. These wells would be located on the same pads as the production and steam injection wells.



Source: Aera, 2016.

0 900 1,800
FEET

Aera Energy LLC Property
Project Footprint
Proposed Project Conservation Easement
Fresh Water Piping*
Other Piping

* To be finalized based on the location of two proposed new groundwater wells.

Figure 2-9

Intra-field Pipelines

2.5.4.4 Reservoir Maintenance Distribution

The reservoir maintenance distribution system is the conduit for transporting recycled produced water from the central processing facility to the Upper Sisquoc water injection wells. The distribution system would start at the central processing facility exit and the terminus would be at the connection point for each injection well's flowline (injection line).

2.5.4.5 Miscellaneous Field Piping

Miscellaneous field piping includes fresh water gathering pipelines, soft water pipelines connecting the central processing facility to the steam generation site, produced gas pipelines, fuel gas pipelines between the central processing facility and the steam generation site, and fire suppression water pipelines (see Figure 2-9 [Intra-field Pipelines], as well as additional information in Appendix B).

2.5.4.6 Electrical Distribution

Electrical power within the central processing facility would be distributed from the Project's 115 kV/12 kV substation (see Section 2.6.6.2, Construction Methodology for Electrical Power Line Interconnection) to several power distribution centers. The power distribution centers would include disconnects, breakers, 12 kV to 480 volt transformers and motor control centers. Electrical power from the motor control centers would be run to the motor and lighting loads within the central processing facility.

Electrical power to the field loads would be run on a 12 kV primary/480 volt secondary overhead power distribution system. Pole or pad-mounted mounted transformers would be located throughout the field development. The pole mounted 480 volt secondary electrical power would service each well pad and the steam generation site.

2.5.4.7 SCADA Networks

The Project would utilize a distributed control system for normal operation of process equipment. Some individual equipment may also include programmable logic controllers. The distributed control system and programmable logic controllers would control equipment and processes and provide data on process conditions and performance. When applicable, distributed control system and programmable logic controller communication would utilize fiber optic networks.

Process control and monitoring stations would be located in the central processing facility control building. The monitoring and control stations would be configured to provide data and status information to assist operators to quickly identify and resolve issues. Field measurement and control equipment would be configured to be monitored and operated both locally and from the central processing facility control building. In the event of a serious out-of-normal-range condition, the distributed control system and local equipment programmable logic controllers would be programmed to safely shutdown equipment and processes. Additional information regarding emergency shut-down systems is included in Section 2.5.7 (Emergency Shutdown Systems), below.

2.5.5 Support Infrastructure

2.5.5.1 Buildings

The Project would include a production office, warehouse and maintenance shops, a central processing facility control building, and a multi-purpose building sited together in the same general area. This office "campus" would provide workspace, meeting rooms, storage, parking, and worker amenities, such as a

changing room, lockers, and showers. All buildings would have a cohesive design theme (materials, color, form) and would be designed to be Leadership in Energy and Environmental Design (LEED) certifiable with energy efficient features, where feasible. The office building "campus" would be sited away from the central processing plant to minimize traffic interference.

Warehouse and maintenance shop buildings would be located adjacent to the central processing plant. An outdoor equipment and materials storage yard would be adjacent to the warehouse. The warehouse would receive, store, and distribute materials needed to support field operations. The mechanical and electrical shops would also be adjacent to the warehouse and would provide space for repairing and maintaining equipment in a controlled environment.

During construction and as may be needed during Project operational periods, temporary, modular buildings may be used to provide any required offices space, meeting space, storage, etc.

2.5.5.2 Lighting

External pole lighting would be provided as needed by buildings, equipment, entrances, roads, parking lots, drilling sites, and other locations to support operational reliability, safety, and security. Lighting would be directed downward and shielded to avoid obtrusive light beyond the central processing facility boundary, reflective glare, or illumination of the nighttime sky.

2.5.5.3 Septic System

The Project would include an onsite septic system that would be designed by a qualified environmental professional and would satisfy all County requirements for soils analysis, percolation testing, groundwater testing, design, and construction/installation. The septic system would be reviewed and permitted by Santa Barbara County Environmental Health Services prior to installation and operation.

2.5.5.4 Fire Protection

The design and operation of the Project would meet provisions within the California Fire Code and standards of the National Fire Protection Association, including the requirements for the storage of hazardous materials, the installation and use of fire protection systems and devices, and the implementation of safety measures for employees and emergency responders, as outlined within the Applicant's Master Fire Protection Plan (August 2014) (Aera, 2016).

The Master Fire Protection Plan includes distribution of fire water throughout the central processing facility. Hydrants and monitors would be positioned at selected locations on the fire water distribution system. Fire monitors may be used to spray a stream of fresh water to cool process equipment adjacent to a fire or monitors may be used with a foaming agent to spray foam for suppression of a pool fire. Buildings would be equipped with applicable overhead fire systems. Project roadways would be designed to meet State and County Fire Code requirements and support access by fire response vehicles for emergency support or wild fire control.

A fresh water storage tank would be sized at minimum of 3,000 barrels (126,000 gallons), and strategically placed within the Project site. A portion of the tank volume would be dedicated to fire water storage. The tank would be placed at an elevation adequate to meet water pressure requirements set forth by the Santa Barbara County Fire Department.

2.5.6 Utilities and Communications

2.5.6.1 Natural Gas Pipeline and Associated Facilities

The Project includes a new 14-mile, 8-inch natural gas pipeline to deliver natural gas fuel at a sufficient rate to meet the needs for thermal enhanced oil recovery steam generation. Southern California Gas Company (SoCalGas) would design, build and operate the new natural gas pipeline, which would be subject to California Public Utilities Commission (CPUC) standards and would provide 13 million standard cubic feet per day of utility grade natural gas at a minimum pressure of 300 pounds per square inch (psi) gage.

The proposed natural gas pipeline and associated facilities would originate at the existing SoCalGas Line 1010 at Divide Station, located along Graciosa Road, and would terminate at Aera's proposed central processing facility located in the southwest corner of the Project site (see Figure 2-10, Proposed Natural Gas Import Pipeline Route). The natural gas pipeline would be primarily installed in the existing public utility corridor within the public right-of-way, under existing road pavement.

Approximately three preliminary staging areas would be required to store pipe and provide a location for the contractor to stage equipment and materials during construction. No new roads would be constructed as part of this component of the Project and no existing roads would require additional grading or improvements for natural gas pipeline construction activities. At this time, prolonged complete road closures are not anticipated. However, temporary roadway or lane closures would be determined by the County Public Works Department and pre-approved sections of the public roadway may be temporarily closed in accordance with local encroachment permit requirements.

In addition to the natural gas pipeline, SoCalGas would construct associated facilities which include: two permanent, aboveground isolation valves; four underground isolation valves; and a metering station. Each isolation valve would include automatic shut-off and SCADA equipment. At Divide Station, all of the equipment would be located within the existing fenced limits. Isolation at the Project delivery point would require a fenced enclosure measuring approximately 60 feet by 120 feet. Cathodic protection to protect the natural gas pipeline from corrosion would be installed, as required.

2.5.6.2 PG&E Electrical Power Line Interconnection

The existing facilities on the Project site are currently being served electrical power from PG&E's 12 kV distribution system via the existing Palmer Substation. The Project would require transmission-level service interconnection as the Project site load demand increases. The expected maximum electric load of the Project is approximately 12 megawatts (MW) to power all petroleum facility processing, field and office operations, maintenance, monitoring, control and communication systems. Therefore, the proposed Project would include the construction of a PG&E 115 kV power line interconnection as well as an onsite Aera-owned 115 kV/12.47 kV substation.

Aera has submitted an application to PG&E for an approximate 0.3-mile overhead power line interconnect from PG&E's existing Sisquoc–Santa Ynez 115 kV power line to the new onsite Aera-owned 115/12.47 kV substation, as described below (see Figure 2-11, Electrical Power Line Interconnection). The 115 kV power line would be constructed, operated, and maintained by PG&E and the onsite substation would be located within the central processing facility and constructed, operated and maintained by Aera. Aera would take control of the power at the substation. Modifications may also be required at the existing PG&E-owned substations (i.e., Sisquoc or Palmer Substations). In addition, some relays setting adjustments would be required at Santa Maria and Mesa Substations. Work at existing PG&E-owned substations is expected to occur within the substation fence line.

LEGEND:

- Proposed Staging Area
- Proposed Common Carrier Natural Gas Pipeline Route
- Aera Energy LLC Property Boundary
- Parcel Boundary
- Project Footprint

Source: Aera, 2016.

0 1,600 3,200
FEET

Figure 2-10
Proposed Natural Gas Import Pipeline Route

Source: Aera, 2016.

0 350 700
Feet

Aera Energy LLC Property
Project Footprint
Approximate Route of Existing 115kV Line
Proposed 115kV Service Line
Proposed Laydown Area - 100'x100'
Proposed Staging Area within Existing Palmer Substation

Figure 2-11

Electrical Power Line Interconnection

The CPUC would have sole jurisdiction over the siting and design of the power line component of the Project because it authorizes construction, operation, and maintenance of investor-owned public utility facilities. Although such projects are exempt from local land use and zoning regulations and discretionary permitting (i.e. they would not require any land use approval that would involve a discretionary decision to be made by Fresno County), General Order No. 131-D, Section XIV.B, requires that in locating a project "public utility shall consult with local agencies regarding land use matters." The Applicant anticipates that the power line would quality for a permit exemption under General Order No. 131-D Section III.B(1)(f), and that PG&E would file a Notice of Construct with the CPUC for construction of the power line (CPUC, 1995).

Interconnection of the proposed Aera-owned 115/12.47 kV substation to the existing electric transmission grid would require construction of a new 115 kV power line tap from the Sisquoc–Santa Ynez 115 kV Power Line. Although design is preliminary, the Project would be supported by up to approximately ten tubular steel poles or light-duty steel poles. Approximately five structures would likely be interset either between or in place of the existing alignment along the Sisquoc–Santa Ynez 115 kV Power Line. Of those 10 poles, approximately 5 structures would be installed along the new 115 kV power line tap to the proposed Aera-owned 115/12.47 kV substation. Approximately five existing single-circuit wood poles may be removed from the Sisquoc–Santa Ynez 115 kV Power Line. The total length of the new power line associated with the Aera-owned 115/12.47 kV substation would be approximately 0.3 miles. The tubular steel poles would be supported on concrete foundations approximately 6 feet in diameter and up to 35 feet deep. The structures would be approximately 60 to 100 feet tall. For a temporary period during construction of the line, PG&E would move one to two spans (approximately 1,000 feet) to the south of the existing alignment using six temporary wood poles to keep the line in service but away from the construction area.

The substation would consist of incoming metering and switching equipment, transformers, and protective equipment to monitor and provide protection for the various circuits providing power to the central processing facility and field lifting equipment (Figure 2-12, Central Processing Facility Plot Plan). The incoming 115 kV power line from PG&E would come into the Aera-owned substation via overhead aluminum conductors terminating on an A-frame structure that also contains switches and the metering equipment that records the usage from which PG&E bills the end user. Following the A-frame is the high voltage circuit breakers that protect the facility from over and under voltage conditions, as well as fault conditions (abnormal electric current) that may develop on the PG&E side of the service, and faults that could possibly come from the substation side.

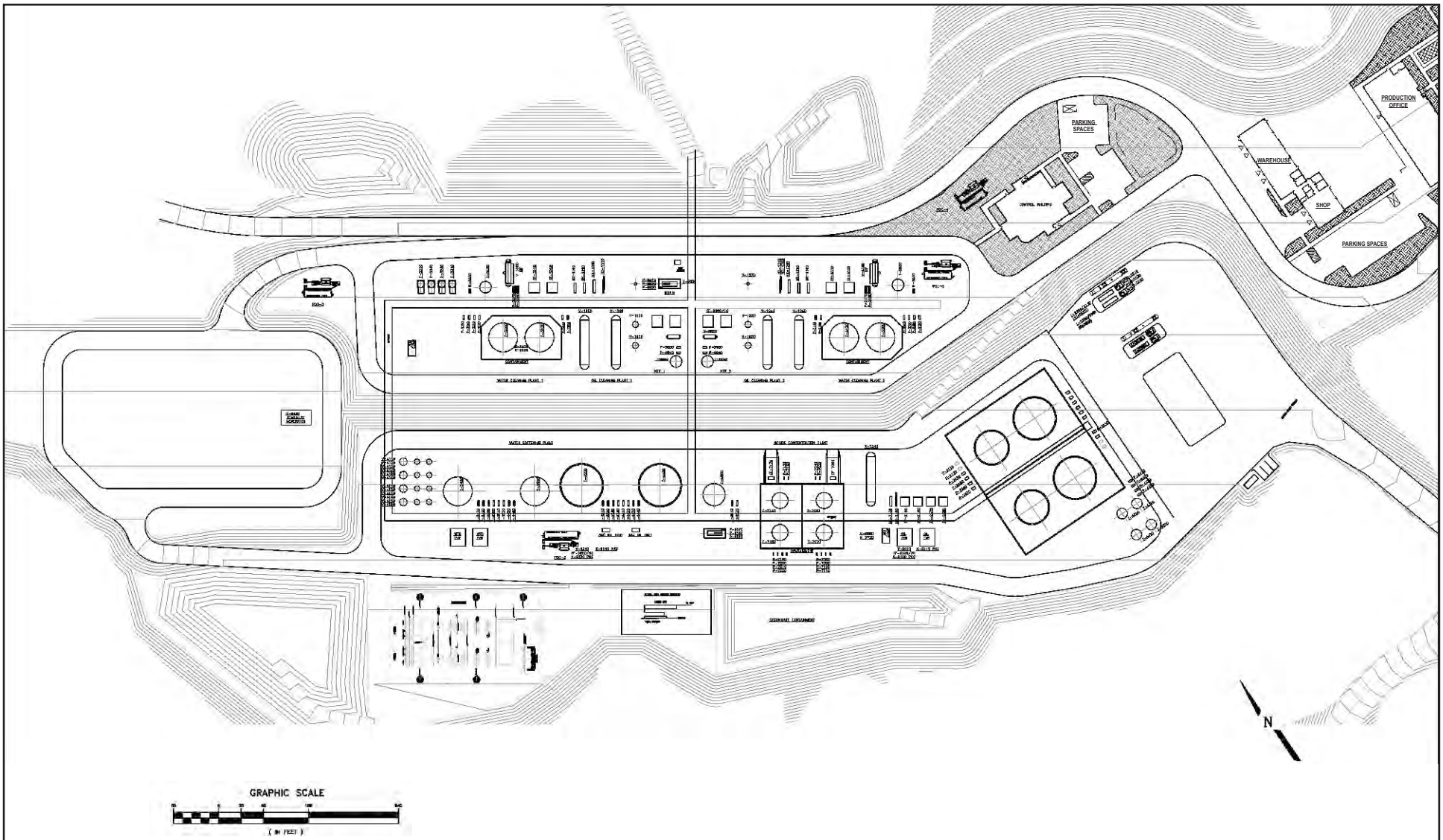
The Project has been designed to satisfy the requirements of the PG&E's Transmission Interconnection Handbook and meet all applicable California Independent System Operator and Western Electricity Coordinating Council standards.

2.5.6.3 Other Utilities

No public domestic water service nor public sanitary waste service are currently available or proposed for the Project.

2.5.7 Emergency Shutdown Systems

Aera would develop an Emergency Response Plan specifically tailored to both the construction and operational portions of the proposed Project site (see Section 2.8.1.1, Personnel and Facility Safety Protocol/Emergency Response). In addition, personnel and the environment at the Project site would be protected by shutdown systems designed to:



Source: Aera, 2016.

Figure 2-12

Central Processing Facility Plot Plan

- Shut down and block-in individual production wells; and
- Interrupt the electric power distribution system to terminate production lift.

Control systems would be installed on individual producing wells to monitor surface temperature, surface pressure, and well lift system performance. Out of range conditions at any individual well would result in a shutdown of the lift system for that well as well as closure of an emergency shutdown valve on the flowline from that well. The emergency shutdown valve protects the gathering system and other downstream pressure piping from overpressure by the production well. Out of range conditions (temperature or pressure) at well pads or at the central processing facility (multiple types) may also result in a signal to effect shutdown of individual production well lift.

In addition to the capability to remotely shutdown individual production wells, the electrical distribution system for production well lift would be designed to allow interruption of all production wells with a single switch. In the event of a shutdown, the process control, fluid inventory, and containment systems would be designed to contain the balance of fluids in the gathering system and in the central processing facility.

Liquids would continue to be processed and contained in the piping and equipment of the plant, vapors would continue to be collected and combusted.

2.5.8 Site Access, Access Roads and Staging Areas

2.5.8.1 Site Entrances

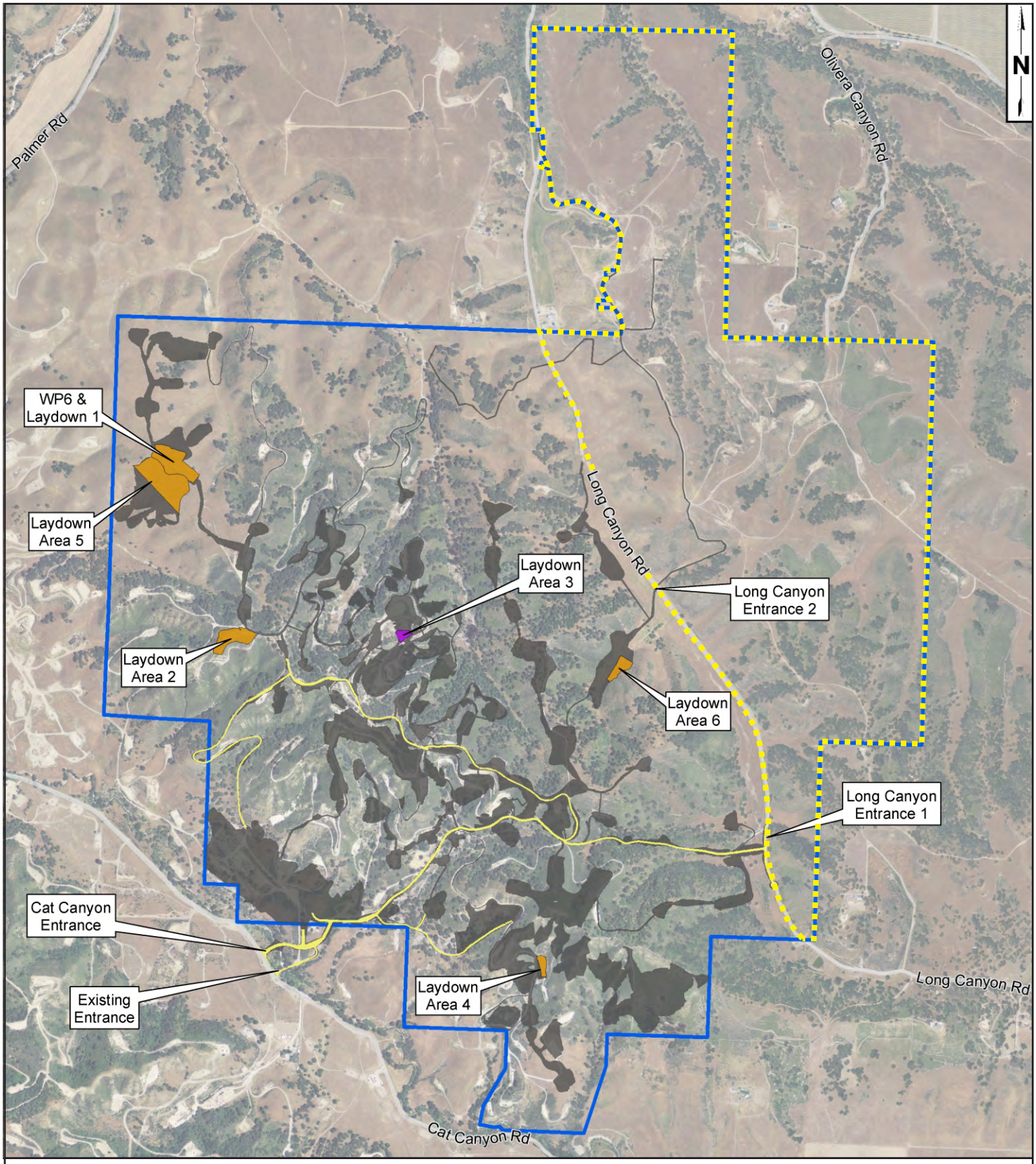
The primary Project site entrance for the oil field is currently located at 6516 Cat Canyon Road, but a new Project site entrance located approximately 300 feet north of the existing entrance would be developed to safely enable two-way tanker truck traffic into and out of the Project site (see Figure 2-13, Project Site Entrances and Staging Areas). The existing site entrance would remain in place following construction of the new Project site entrance across Cat Canyon Creek. All tanker trucks would deliver and reload at the central processing facility only, via the improved main site entrance.

The Project would also include improvements to a secondary access located along Long Canyon Road, on the eastern boundary of the Project site. The Long Canyon Road entrance would also be constructed during the initial Project construction (Phase I). During Phase II, one smaller east side entrance from Long Canyon Road would be constructed to provide adequate access to new well pads nearby. This smaller entrance is expected to utilize an “Arizona” swale crossing over a shallow drainage area. Creating two entrances on the east side of the Project area would maximize the use of the existing roadway (Long Canyon).

2.5.8.2 Site Access

The oil field is private property and would not be open to the general public. However, a separate portion of the property, east of Long Canyon Road, which is not proposed for oil production, has been proposed as a Conservation Area. The proposed Conservation Area may include some public access, consistent with the primary goals of conservation and conservation education. To access the site, the Project would utilize a combination of one (or more) of the following three local roadway route alternatives between the Project site and U.S. Highway 101 (see Figure 2-14, Proposed Trucking Routes to Highway 101 Detail):

- *Route Option 1* – Cat Canyon Road to Dominion Road to Clark Avenue to U.S. Highway 101;
- *Route Option 2* – Cat Canyon Road to Dominion Road to Clark Avenue to Telephone Road to Betteravia Road to U.S. Highway 101; and
- *Route Option 3* – Cat Canyon Road to Dominion Road to Foxen Canyon Road to Betteravia Road to U.S. Highway 101.



Source: Aera, 2016.

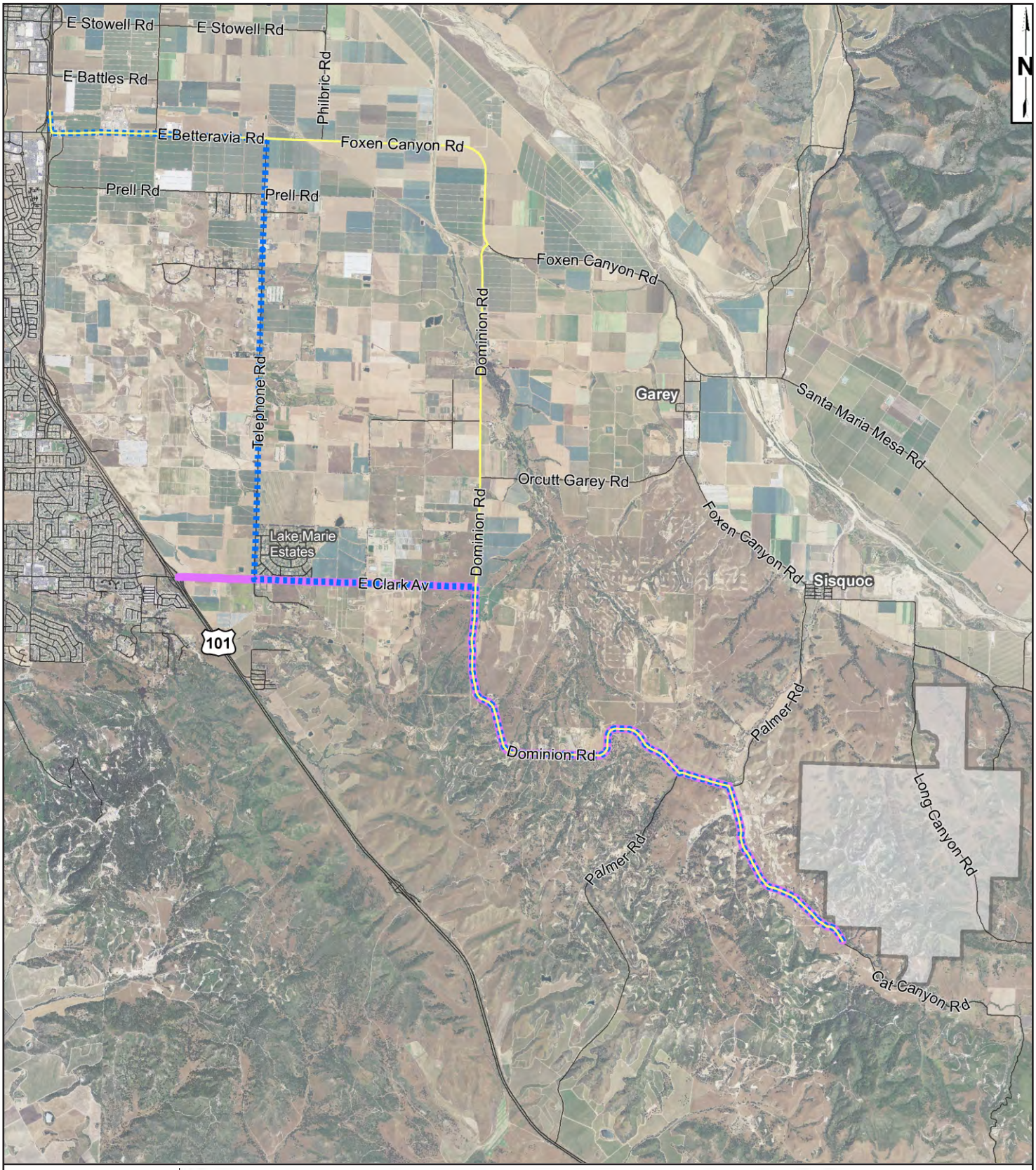
0 900 1,800
FEET

Aera Energy LLC Property
Project Footprint
Primary Site Access Road
Proposed Project
Conservation Easement

Laydown Areas
Phase I
Phase II

Figure 2-13

Project Site Entrances and Staging Area



Source: Aera, 2016.

Aera Energy LLC Property
Project Option 1
Project Option 2
Project Option 3
Existing County Road

0 0.75 1.5
MILES

Figure 2-14

Proposed Trucking Routes to Highway 101 Detail

2.5.8.3 Access Roads

The two main Project site entrances would be connected via a primary site access road, which would be graded and paved concurrently with site entrance construction activities (Phase I). Secondary roadways would vary in width as follows:

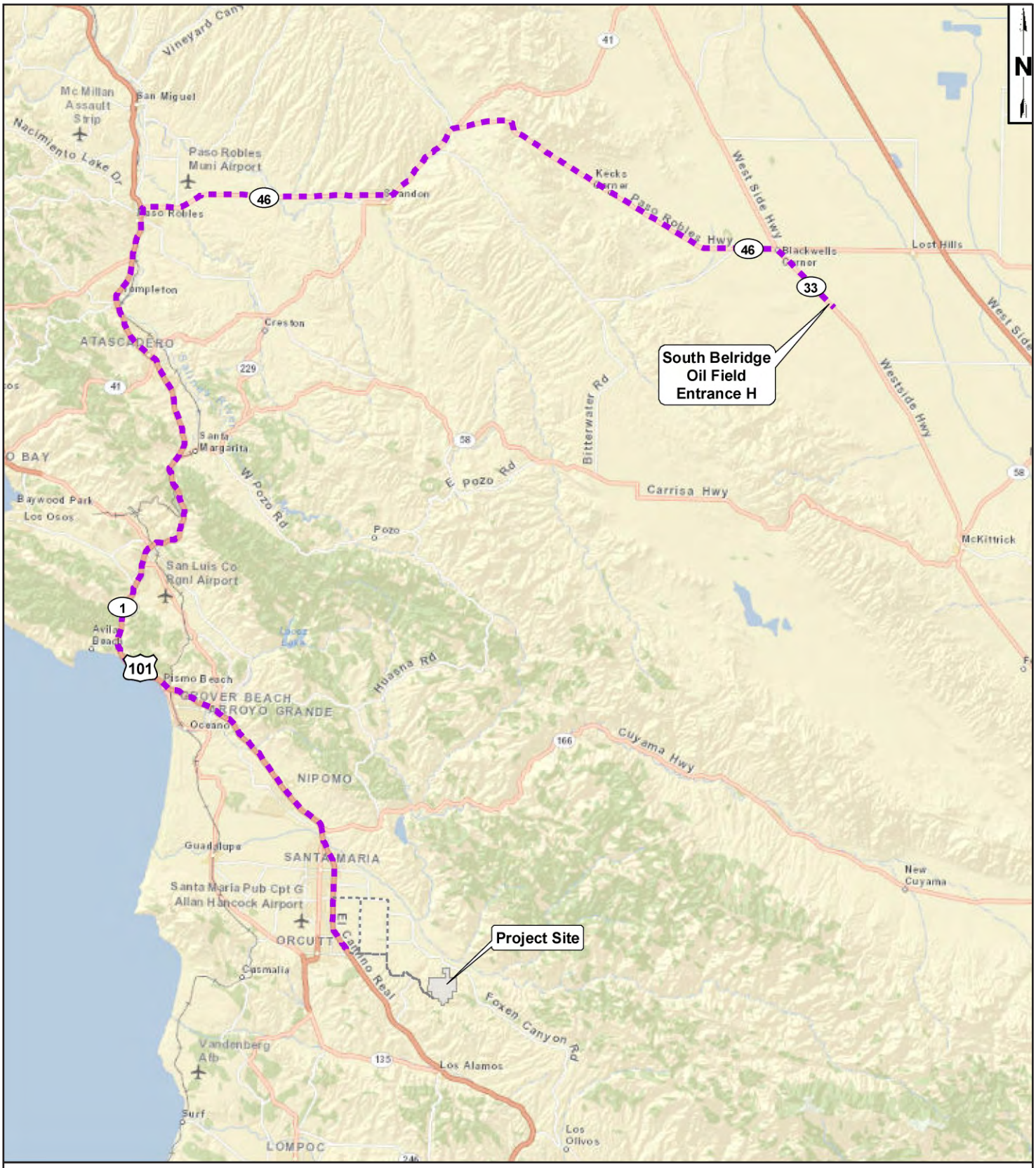
- Cat Canyon Road (proposed new primary) entrance – 40 feet wide;
- Cat Canyon Road (existing, proposed as secondary) – approximately 20 feet wide;
- Long Canyon Road entrance #1 – up to 24 feet wide; and
- Long Canyon Road entrances #2 and #3 – 20 feet wide.
- No new public roads are proposed as part of the Project. Existing lease roads would be utilized whenever feasible to access the proposed new Project areas. However, over 9 miles of new field access roads would be constructed (see Section 2.6.1.3, Proposed Grading and Site Development). All access roads would be designed to meet State and County Fire Code requirements (ranging from approximately 20-40 feet in width).

2.5.9 Produced Oil Transport

- During both phases of operation, light crude would be imported by truck, blended with produced oil, and transported by truck. The source of the light crude and the destination of the blended production would most likely be Aera's Belridge Producing Complex (South Belridge Oil Field) located approximately 45 miles west/northwest of Bakersfield in Kern County, California (140.4-mile one-way trip; see Figure 2-15, Regional Roadway Map). Adding light crude oil to the produced oil would facilitate oil dehydration and produced oil transportation by lowering the viscosity of the produced oil. The light crude oil receiving facilities would consist of truck offloading racks, unloading pumps, meters, and storage tanks located within the central processing facility. For Phase I (approximately Year 1 through Year 5), an estimated 1,366 barrels per day of light crude oil would be needed (9 tanker truck loads/day). At peak production during Phase II, an estimated 3,281 barrels per day of light crude oil (a peak of 21 tanker truck loads/day) would be required. Produced oil transport during field operations is further discussed in Section 2.7 (Produced Oil Transport).

2.5.10 Water Use

- Water would be used to generate the steam that would be injected into the reservoir to enhance oil recovery. No fresh water would be used to generate steam for the Project. The majority of the steam would be generated using produced water from the Brooks reservoir, which is anticipated to peak at an average rate of 35,000 to 40,000 barrels of water per day. Water from the Brooks reservoir is not suitable for domestic or agricultural use due to its high salinity content.
- To supplement the expected produced water volumes reused to generate steam, additional brackish (high salinity content) water would be produced from the Upper Sisquoc Formation sands, which lie above the Brooks reservoir (Figure 2-16, Generalized Geologic Cross Section). Produced water from both the Brooks reservoir and Upper Sisquoc Formation sands would be treated, heated, and injected into the Brooks reservoir as steam. The water softening treatment process creates a small volume of brine (salty water).

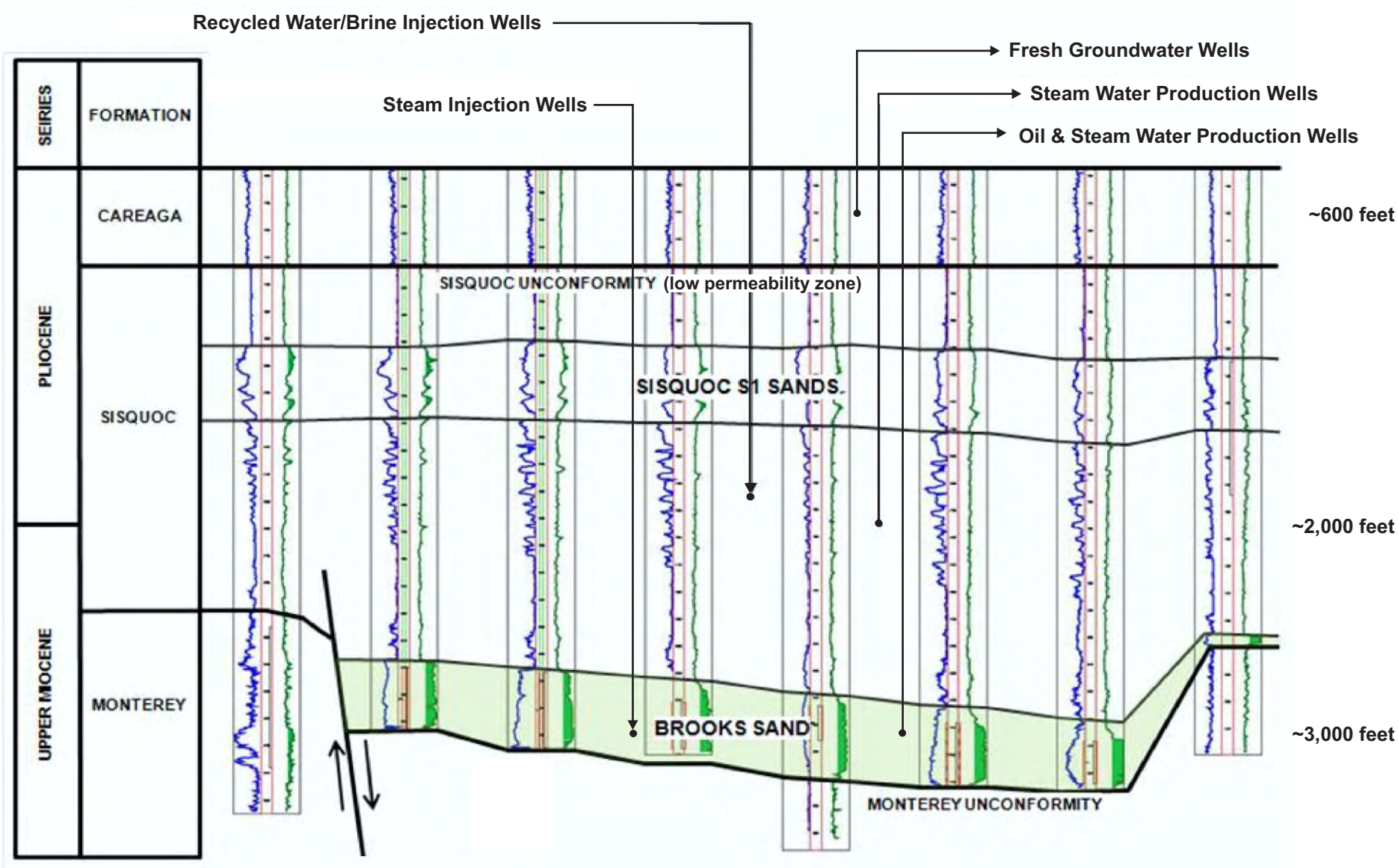


Source: Aera, 2016.

0 5 10
MILES

Aera Energy LLC Property
Proposed Route Option to U.S. Highway 101
Proposed Route to Belridge

Figure 2-15
Regional Roadway Map



Source: Aera, 2016.

Figure 2-16

Generalized Geologic Cross Section

To offset withdrawal from the Upper Sisquoc Formation sands, excess produced water not used for steam injection, including the brine from softener re-generation, would be combined and re-injected into the Upper Sisquoc Formation sands at the same depth. These sands are oil bearing, with an expected average Total Dissolved Solids (TDS) of 11,000 parts per million (PPM) or greater. Peak Upper Sisquoc Formation sands withdrawal and produced water and brine re-injection for Phase I and Phase II is anticipated to be approximately 15,500 barrels of water per day and 5,800 barrels of water per day, respectively. The Upper Sisquoc produced water wells and injection wells would be designed to meet all DOGGR requirements.

Table 2-5 (Produced Water Injection and Brine Volumes) shows the annual volumes of produced water from the Brooks reservoir and Upper Sisquoc Formation, as well as the amount and percentages of produced water that would be used for steam injection, and the amount of brine that would be reinjected. All produced water would be reinjected as steam or brine. Prior to injection/disposal, water quality tests would be regularly performed on produced water and water treatment brine. These tests would typically include geochemical, TDS, Total Suspended Solids (TSS), and Millipore analyses.

Table 2-5. Produced Water Injection and Brine Volumes

	Projected Water Volumes, Million Barrels/Year			
Produced Water Source/Destination	**Year 1**	**Year 2-6**	**Year 7**	**Years 8+**
Water produced from Upper Sisquoc Formation	3.4	3.3	6.2	6.1
Water produced from Brooks Reservoir	1.1	4.2	2.0	7.7
Injected as steam	4.0	6.7	7.3	12.3
Percent produced water injected as steam	89%	89%	89%	89%
Brine (from produced water treatment)	0.5	0.8	0.9	1.5
Brine reinjected into Sisquoc Formation	0.5	0.8	0.9	1.5

Source: Aera, 2017.

Fresh groundwater would be needed for utility purposes including but not limited to fire protection, lavatories, showers, equipment cleaning, dust control, grading, compaction, well drilling, and minor landscape irrigation. Water conservation measures would be used where practicable to reduce fresh groundwater use. Fresh groundwater consumption throughout the duration of the Project (construction plus operations) would range between 16 and 21 acre-feet per year, plus an additional 4 acre-feet per year for oak tree replacement watering during the first few years of the Project. If available and practicable, Aera may use reclaimed water for dust control and soil conditioning needs. Produced water would not be used for construction-related water needs. Proposed water use by year is shown in Table 2-6.

Table 2-6. Water Use by Year (acre-feet/year)

Phase	**1**	**1**	**1**	**1**	**1**	**2**
Year (estimated)	**1**	**2**	**3**	**4**	**5**	**6**
Staff water use	2.2	2.2	2.2	2.2	4.5	4.5
Landscape irrigation	0.2	0.2	0.2	0.2	0.2	0.2
Fire water system testing/flushing	0	0.52	0.52	0.52	0.52	0.52
Grading-Related Water Use						
Water use (grading)[1]	1.83	2.14	5.29	0.25	0.00	0.00
Dust control[2]	9.20	9.20	9.20	9.20	9.20	9.20
Well Drilling						
Wells drilled	0	0	59	0	2	2

Table 2-6. Water Use by Year (acre-feet/year)

Phase	1	1	1	1	1	2
Year (estimated)	**1**	**2**	**3**	**4**	**5**	**6**
Drilling water use	0	0	1.90	0.00	0.06	0.06
Oak tree irrigation[3]	0	3.58	3.58	3.58	3.58	3.58
TOTAL	**13.43**	**17.84**	**22.89**	**15.95**	**18.06**	**18.06**

Source: Aera, 2017.
1 - Assumes adding 2.24 gallons per cubic yard of fill (on-site borrow source [sand and sandstone], desired moisture content =
2 - Assumes one 4,000 gallon water truck filled three times per work day (12,000 gallons/day, 250 days per year)
3 - Assumes all oak trees planted at once.

Although fresh water use would average less than 25 acre-feet per year, the Project would be designed to have additional fresh water supply to cover infrequent or contingent demand, for instance, during water well maintenance, water tank filling, or firefighting.

Accordingly, up to three groundwater wells would be completed to deliver 50 gallons per minute each or 150 gallons per minute total (up to 0.66 acre-feet per day) to supply the extra contingent volume only if and when it is needed. As discussed in Section 2.6.2, the Project would use one existing onsite source well (McCroskey-WS12[3]), which currently draws water from the Careaga and the Paso Robles Formations within the Santa Maria Groundwater Basin, as well as one or two other freshwater wells. Aera has stated that it is also looking into the practicable availability of reclaimed water sources that could be used to reduce fresh water use.

In addition, a 3,000-barrel fresh water storage tank would be strategically placed within the Project site. A portion of the tank volume would be dedicated to fire water storage. The tank would be placed at an elevation adequate to meet water pressure requirements set forth by the Santa Barbara County Fire Department.

2.5.11 Conservation Easement

A permanent Conservation Area of up to 687 acres is proposed for a portion of the eastern side of the Project site, east of Long Canyon Road, where no surface oil production activities are proposed. The Conservation Area would also be used to provide various mitigation opportunities for Project impacts, to conserve and protect special-status species and their habitats, and to honor the existing agricultural preserve uses of the site. In addition, the Conservation Area would provide educational and recreational opportunities for the Santa Barbara County community. The size of the Conservation Area would cover the acreage needed to fulfill mitigation requirements; however, Aera may authorize additional conservation acreage in the future.

The Conservation Area would be protected by a permanent Conservation Easement, which would be managed, monitored, and maintained in perpetuity under the guidance of a Conservation Management Plan, based on agency permit conditions of approval and the final approved Project design.

A Conservation Plan would incorporate additional elements such as: the recordation of a Final Tract Map to establish the final boundaries of the Conservation Area, recordation of a Conservation Easement over the Conservation Area that would be executed once the Project has obtained the required regulatory permits, the identification of a Land Manager and Conservation Easement Holder, the Conservation Area

[3] Water well McCroskey-WS12 has a sustainable pumping rate in the range of 125 gallons per minute (180,000 gallons per day).

funding mechanism, and the finalization of regulatory agency permits which may have bearing on the long-term responsibilities of the parties involved. It would also describe Conservation Area operations and administrative processes.

2.6 Construction

This section describes the construction of the Project components discussed in Section 2.5 (Proposed Project Components). The Project is proposed to be implemented in phases to maximize efficiency and help moderate construction and operational peak activity levels. The majority of the processing facility construction for the field redevelopment would occur in two major phases; Phase I and Phase II (Figure 2-6, Project Overview and Phasing).

Phase I plant and infrastructure construction would occur for approximately 3 years preceding the first steam injection and would continue for approximately 3 years after the first steam injection. Phase II would occur for the remaining 27 or more years of production. Grading of well pads and roadways, installation of intra-field gathering and distribution pipelines, installation of intra-field electrical distribution, well drilling and completion, and well hookups would occur throughout a multi-year field infrastructure program beginning in Phase I and continuing through Phase II.

2.6.1 Site Preparation

2.6.1.1 Removal of Existing Facilities

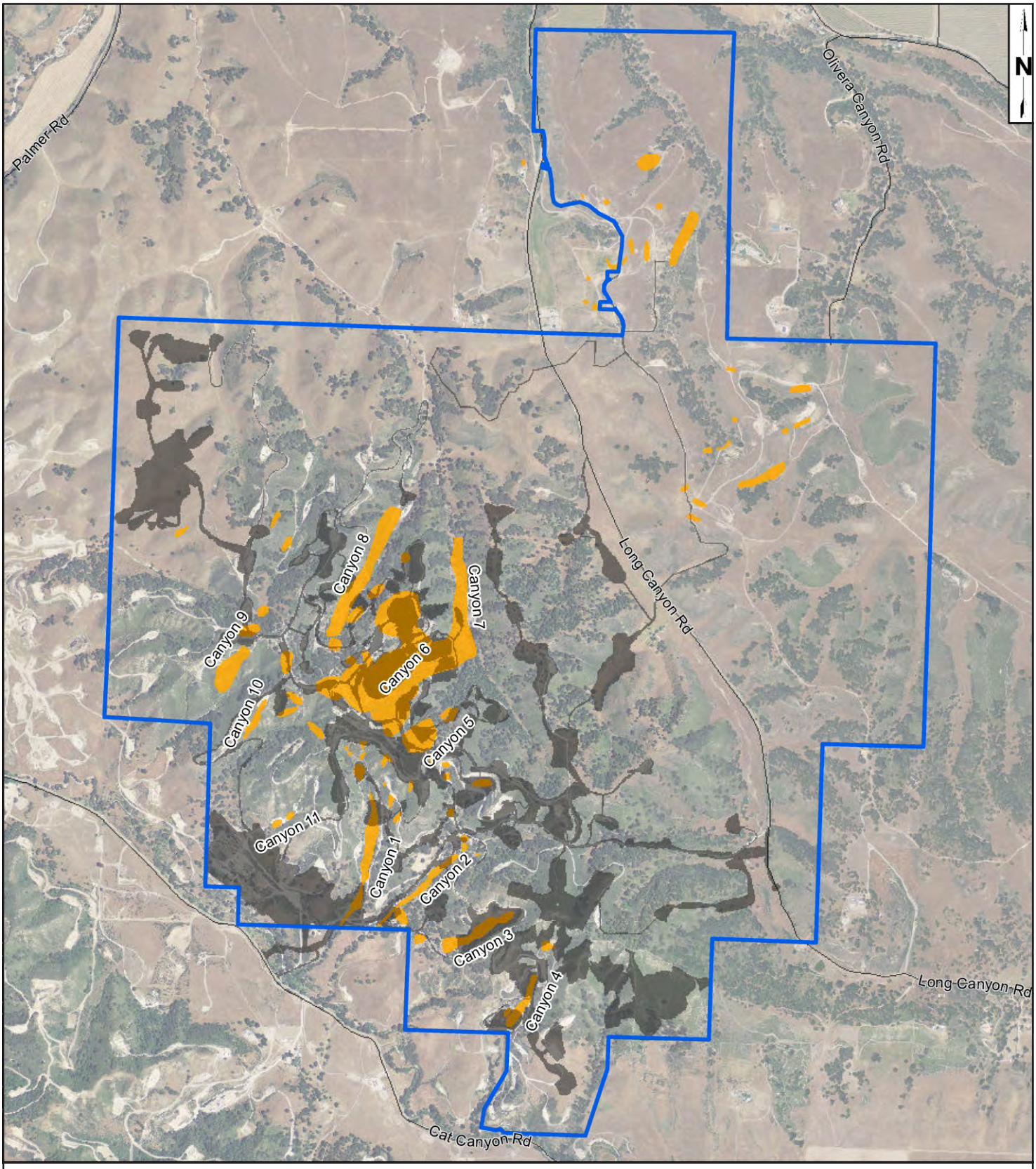
The Project site currently supports office/warehouse buildings, abandoned oil wells, four non-producing test wells, five active wells operated by other operators, a system of graded access roads and well pads, former facility locations, a permitted beneficial reuse site, fresh groundwater wells, firewater and grazing tanks, and cattle grazing. There is some debris from former operations, such as broken concrete, in scattered locations throughout the Project site. Debris would be reused or recycled to the extent feasible, or disposed of at the Santa Maria Regional Landfill.

2.6.1.2 Legacy Fill Areas

Various areas throughout the Project site are known to contain pre-existing petroleum hydrocarbon-containing soils. These “legacy fill areas” are remnants from historical oil and gas operations within East Cat Canyon prior to acquisition of the property by Shell and Aera (see Figure 2-17, Legacy Fill Areas). Project construction activities would encroach upon some legacy fill areas. Aera would excavate approximately 255,673 cubic yards of petroleum hydrocarbon-containing soils within the Project disturbance areas for beneficial reuse either onsite as road material, at other Aera locations, or at the Santa Maria Regional Landfill, in accordance with the Soil Beneficial Reuse Plan developed for the Project (Aera, 2016).

2.6.1.3 Proposed Grading and Site Development

The Project would require the grading of 305 acres, or 14 percent of the Project site’s 2,112 total acres (2,108 acres of Aera-owned parcels and 4 acres of Project footprint located on adjacent parcels). Of the 305 acres that would be graded, 64 acres or 21 percent is previously disturbed. The net new disturbance acreage would be approximately 241 acres or 11 percent of the total Project site. The 305 acres of disturbance include grading for the central processing facility, the steam generation site, the production group station, well pads, roads and entrances, pipe corridors, building sites (including parking areas), laydown areas, storm water detention basins, site entrances, and a new beneficial reuse site. The Project



Source: Padre Associates, Inc., 2014.

Aera Energy LLC Property
Project Footprint
Legacy Area (TetraTech 2000 & 2001 Reports)
Impact Area

0 900 1,800
FEET

Figure 2-17
Legacy Fill Areas

would maximize the use of existing roads, well pads, cleared areas, and contours wherever possible. Proposed cut and fill volumes are approximately 3 million cubic yards each. Excess spoils would be transported to a designated fill location within the Project Site for re-use as fill material or moved offsite to an appropriate soils disposal or reuse facility.

Due to limiting parameters, including the existing steep terrain, excavation for stormwater quality improvement features including detention basins, and oak tree avoidance, approximately 40,000 cubic yards of excess soil is expected to be generated and balanced onsite. Appendix B (Project Description Supporting Information) provides additional information regarding grading quantities.

Additional ground disturbance would occur for construction of the utilities component of the Project, including the natural gas pipeline and 115 kV power line as described below (see Section 2.6.5 [SoCalGas Natural Gas Pipeline Construction] and Section 2.6.6 [PG&E Electrical Power Line Construction]). Excess spoils from the natural gas pipeline and the electrical power line would be transported to an appropriate soils disposal or reuse facility. The estimated ground disturbance for the natural gas pipeline would be 6.4 acres with an estimated 30,000 cubic yards of cut and fill, located almost entirely within existing public utility easements, under existing asphalt paved roadways. The estimated ground disturbance for the 115 kV power line would be approximately 2.1 acres.

Access Roads

Grading of the Project roads, both existing and new, would occur throughout Phases I and II, concurrent with the multi-year well development schedule. Grading existing access roads will introduce current best storm water pollution prevention practices. Fire Department access roads have been designed to range in width between 20 and 40 feet, maintain a maximum 15 percent grade and withstand a 20-ton vehicle, per Santa Barbara County Fire Department Development Standard #1 (Aera, 2016). Where approved by the Santa Barbara County Fire Department, road grades may exceed 15 percent, and paving would consist of a concrete structural section. Asphalt or concrete paving of Fire Department access roads would occur on road grades exceeding 10 percent slope. Additionally, some secondary access roads would be paved. All other roads would consist of a suitable aggregate material over compacted subgrade soil that can withstand a 20-ton vehicle.

2.6.2 Well Construction, Drilling, and Completion

The majority of the wells drilled at the Project site would be directionally drilled from multi-well pad locations.

2.6.2.1 Well Pads and Roadways

Construction specifications would be developed based on site-specific data (e.g., geotechnical information, site topography, environmental limitations, etc.). Areas within the surveyed Project disturbance limits would be cleared of all vegetation and other deleterious material utilizing heavy equipment. Where appropriate, vegetation would be chipped and utilized for soil stabilization on slopes less than 10 percent. Road and pad locations would be rough graded and compacted, balancing excavation and embankment volumes of soil (to the extent feasible) to within rough grade tolerances. For primary service roads, aggregate road base would be imported and placed on the finished subgrade to rough grade tolerances with motor graders or scrapers. This would be followed by fine grading the aggregate road base with motor graders and compacted with smooth drum rollers to design specifications. Secondary roads would be capped with beneficial reuse materials (road mix). Earthwork would be completed utilizing conventional equipment (e.g., dozers, loaders, scrapers, motor graders, excavators, sheep's foot compactors, smooth drum rollers, water trucks. etc.). An asphaltic emulsion tack coat would be sprayed on the finished road

base surface at locations designated for asphalt paving. Hot mix asphalt concrete would then be imported and spread with a paving machine. Asphalt concrete would then be compacted with smooth drum/ pneumatic rollers to design specifications.

2.6.2.2 Well Drilling and Completion

Well drilling and completion and well-related infrastructure would occur over a multi-year program in support of production operations (see Figure 2-6, Project Overview and Phasing; and Figure 2-18, Well Types and Locations[4]). Figure 2-6 provides estimated years for construction and Project phasing.

Pad Area and Drilling Rig

Well pad construction would minimize additional ground disturbance through use of existing pads to the extent feasible and directionally drilling wells from multi-well pad locations while meeting the technical constraints of drilling and operation of the wells and containment requirements for spill and storm water runoff management. A total of 72 well pad locations are proposed, ranging in size from approximately 0.37 acres to 7.04 acres. Approximately 189.5 acres (including 52.7 acres or 27.8 percent of existing disturbed areas) would be permanently used and maintained for well pads during the life of the Project assuming all drilled wells become permanent wells. Figure 2-19, Typical Well Surface Equipment, depicts of each type of well.

Drilling rigs would operate 24 hours-per-day while drilling, and depending on the type of well, would operate consecutively for 6 to 9 days (see Figure 2-19, Typical Well Surface Equipment). Additional drilling equipment would include: fluid handling equipment, waste storage containers, mud handling system, blow out prevention equipment, spill prevention equipment, hydrogen sulfide detection equipment, two mud pumps, cuttings bin, cat walk, trailer ("dog house") and others.

Construction Methodology

The proposed drilling and production operations would be performed in accordance with DOGGR well regulations. The installation and drilling of oil and gas wells is a multi-step process. Once a well drilling location is determined and prior to the arrival of a drilling rig, a conductor pipe with diverter valves is installed. These valves would allow any fluid that flows into the wellbore during drilling to be diverted and controlled. The drilling rig and supporting drilling equipment is then set up on location and the drilling process begins.

Once the wellbore is drilled to a specified depth, the drill pipe is pulled out of the hole and casing is installed. Casing is a steel pipe that is permanently inserted into the wellbore to create a barrier to prevent fluid transmission. Once the casing has been run to the specified depth, it is then cemented in place, effectively sealing the outside of the casing to the wellbore. The casing also serves as the foundation for the blowout preventer. For this Project, casing and cementing specifications would follow the requirements of DOGGR Field Rule #307-026,[5] which regulates drilling and completion activities in the Cat Canyon Field, East Area.

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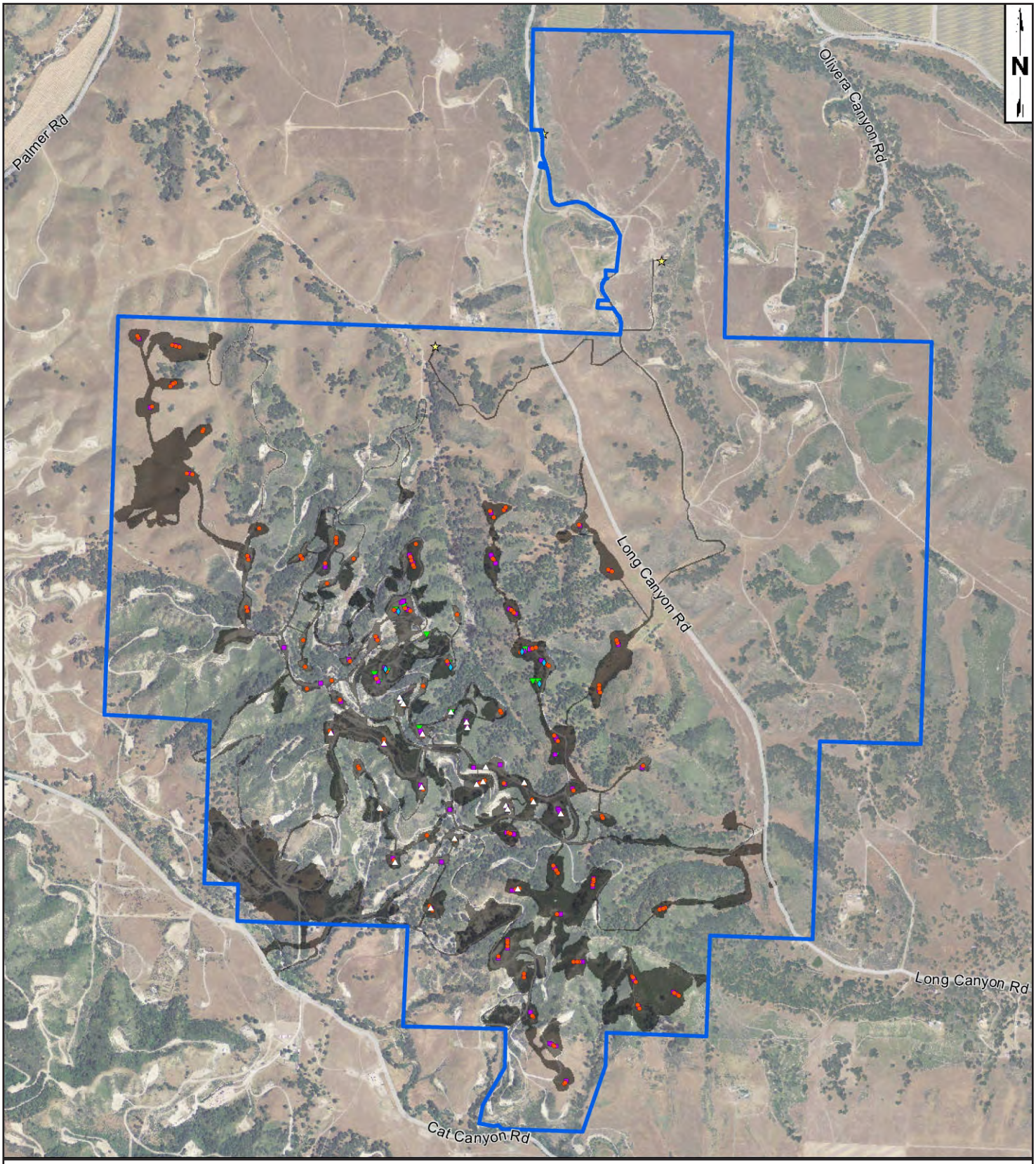
[4] Due to their inactive status, Aera removed water wells Bonetti-WS1 and McCroskey-WS11 from the Project design. These wells have been removed from Figure 2-17; however, the proposed freshwater pipelines to these wells remain as part of the Project footprint and are included in all pertinent impact calculations within Section 4.0 (Environmental Analysis), as up to two additional freshwater wells may be needed as part of the Project.

[5] ftp://ftp.consrv.ca.gov/pub/oil/Field_Rules/Cat_Canyon_East_Sisquoc_307_026.pdf.



Source: Aera, 2016.

Aera Energy LLC Property
Project Footprint

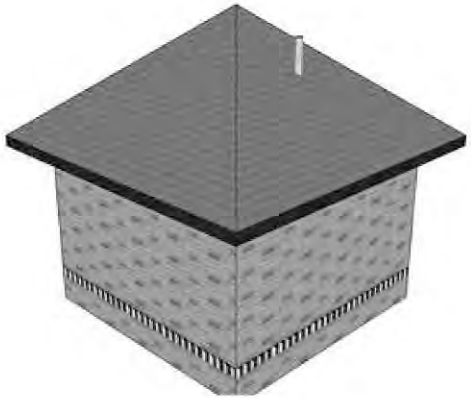
Surface Well Locations
Fresh Water Well
Observation Well
Production Well
Upper Sisquoc Water Production Well
Steam Injection Well
Upper Sisquoc Water Injection Well

0 900 1,800
FEET

Figure 2-18

Well Types and Locations

PRODUCTION WELL



FRESH WATER WELL

STEAM INJECTION WELL

SISQUOC WATER INJECTION WELL

SISQUOC WATER PRODUCTION WELL

Source: Aera, 2016.

Figure 2-19

Typical Well Surface Equipment

A total of three casing strings would be installed on Project wells: a conductor casing, a surface casing which would extend to the base of the fresh water zone, and a production casing string that would reach to the depth of the production zone (i.e., oil bearing formation). In oil production wells a production liner would also be installed and would extend from the production casing into the production zone. The "liner/screen" completion would allow fluid migration from the production zone into the well. Completions would utilize one of two methods, a sized gravel pack for sand control, or a "cased hole" to allow produced fluids to flow into the wellbore (or allow injected fluids [i.e. steam] to flow into the formation) through a purposefully perforated casing. Water production wells would utilize a similar "liner/screen" completion process. No Project wells of any type would be hydraulically fractured.

Well Drilling Fluids and Cuttings Disposition

The drilling process would use a water-based drilling mud composition the primary components of which are gel and water. On average, injection wells would take approximately 6 days to drill, resulting in 1,674 barrels of mud and 372 barrels of cuttings per well. Production wells would take approximately 9 days to drill, resulting in 2,322 barrels of mud and 516 barrels of cuttings per well. The drilling fluids and cuttings would either be reused onsite (i.e., cuttings may be used onsite for fill and road base material) or solidified and then transported offsite to an approved facility for recycling or disposal.

Hydrogen Sulfide Monitoring

Hydrogen sulfide (H_2S) gas is known to occur in the Brooks reservoir and overlying formations. The Aera "Hydrogen Sulfide Policy" would be followed throughout the drilling operations, which addresses monitoring equipment requirements, personnel responsibilities, first aid, and evacuation procedures. Continuous ambient air monitoring for both hydrogen sulfide and lower explosive limits would be in effect for the entire drilling process (Aera, 2016).

Blowout Prevention Equipment

Blowout prevention systems are safety systems that are used in the drilling of an oil and gas well. These systems prevent the uncontrolled release of reservoir fluids and shut off flow to prevent spills and material releases. Blowout prevention equipment would be used during drilling and removed once the well has been completed and secured. Blowout prevention equipment would conform to the DOGGR publication M07 "Blowout Prevention Equipment in California, Equipment Selection and Testing" 2006 Edition.

Lighting System

The drilling operation would provide sufficient lighting to ensure safe working conditions. Vapor proof lighting and wiring would meet the California Division of Occupational Safety and Health specifications. The top of the derrick would have a red beacon to address potential aviation hazards. Rig lighting would be aimed towards the Project site and away from night sky and neighboring properties.

2.6.3 Processing Facilities Construction

Grading for the central processing facility would occur in Phase I and would require approximately 13 total acres of disturbance; existing disturbance would account for approximately 43 percent of this total area. The following outlines construction procedures associated with grading and installation of the processing facilities:

- Site Staging and Equipment Inspection
- Grading, and Installation of Foundations and Equipment

- Installation of Piping Supports and Piping
- Installation of Electrical Panels and Instrumentation Wiring
- Installation of Corrosion Control (i.e. coatings and cathodic protection)
- Start-Up Preparation and Personnel Training
- Testing, Start-Up and Operation

2.6.4 Field Systems Construction

The proposed Project would include the installation of a system of onsite gathering and distribution lines for various co-located services, including production gathering, steam distribution, source water gathering, reservoir maintenance distribution, fuel gas distribution, softened water transfer, separated produced gas, as well as fresh water distribution (see Figure 2-9, Intra-field Pipelines).

2.6.4.1 Intra-Field Pipelines

The field gathering and distribution system would be designed to locate pipeline corridors primarily along roadways on raised pipe supports to minimize external corrosion. Construction sequencing/timing would be concurrent with the well pad and roadway development with the exception of the pipeline corridor leading from the central processing facility to the production group station and steam generation site. This corridor would not be located along roadways and construction is estimated to begin in the middle of Phase I.

The sequence of general construction procedures associated with the installation of intra-field pipelines would be as follows:

- Mobilization and Staging
- Surveying, Staking and Flagging
- Clearing and Grading
- Hauling and Stringing
- Pipe Bending, Welding, Inspection, and Coating
- Pipeline Installation and Testing

2.6.4.2 Intra-Field Electrical Distribution

The intra-field electrical distribution system would be constructed concurrently with the well pad and roadway development with the exception of the overhead distribution line leading from the central processing facility to the production group station and steam generation site, which would be constructed in the middle of Phase I.

Once poles are erected, the conductor would be strung from conductor pull and tension sites at the end of the power line interconnection alignment moving from one pole to the next. Each conductor would be pulled into place at a pre-calculated sag and then tension-clamped to the end of each insulator. The sheaves and vibration dampers and accessories would be removed once installation is complete.

2.6.4.3 Fresh Water Distribution System

Fresh groundwater for the Project would come from one source well which currently exists on the Project site, and up to two new wells.[6] The fresh water distribution system would consist of approximately 24,055 linear feet of three to four-inch high density polyethylene pipe or a fiberglass reinforced polyester pipe and would be buried approximately 1 to 4 feet underground. Installation of the water lines would primarily occur within previously disturbed roads and pathways. Installation of water lines in undisturbed areas would result in a 12-foot-wide disturbance corridor.

2.6.5 SoCalGas Natural Gas Pipeline Construction (offsite)

The Project includes the installation of a new 14-mile, 8-inch natural gas pipeline that would be designed, built, operated and maintained by SoCalGas, as described in Section 2.5.6.1 (Natural Gas Pipeline and Associated Facilities). The pipeline would be built in an existing public utility right of way (ROW) under existing paved roads. The natural gas line would be in place prior to the first steam injection.

The proposed natural gas transmission pipeline would be installed using conventional trenching, as well as horizontal directional drilling, slick bore, and jack-and-bore techniques. The estimated ground disturbance for the natural gas pipeline would be 6.4 acres with an estimated 30,000 cubic yards of trenched soils. Excess spoils generated during the course of the natural gas pipeline construction project would disposed at a permitted disposal site. As previously discussed, in addition to the natural gas pipeline, SoCalGas would construct two permanent, aboveground isolation valves; four underground isolation valves; and a metering station.

2.6.5.1 Access and Staging Areas for Natural Gas Pipeline Construction

The natural gas pipeline component of the Project would be accessed by existing public roadways and dirt roadways that intersect paved roadways adjacent to the route. No new roads would be constructed as part of this component of the Project and no existing roads would require additional grading or improvements for natural gas pipeline construction activities.

SoCalGas has identified the need for approximately three preliminary staging areas to store pipe and provide a location for the contractor to stage equipment and materials during construction. Preliminary Staging Areas are in Table 2-7 (Preliminary Natural Gas Pipeline Staging Areas) and on Figure 2-10 (Proposed Natural Gas Import Pipeline Route).

Table 2-7. Preliminary Natural Gas Pipeline Staging Areas

Staging Area	Approximate Size	General Location	Nearest Station Number
A	1 acre	Corner of Orcutt Road and Clark Avenue	170+00
B	1 acre	West of Dominion Road on the north side of Clark Avenue	424+00
E	1 acre	North side of Dominion Road	590+00

Source: Aera, 2016.

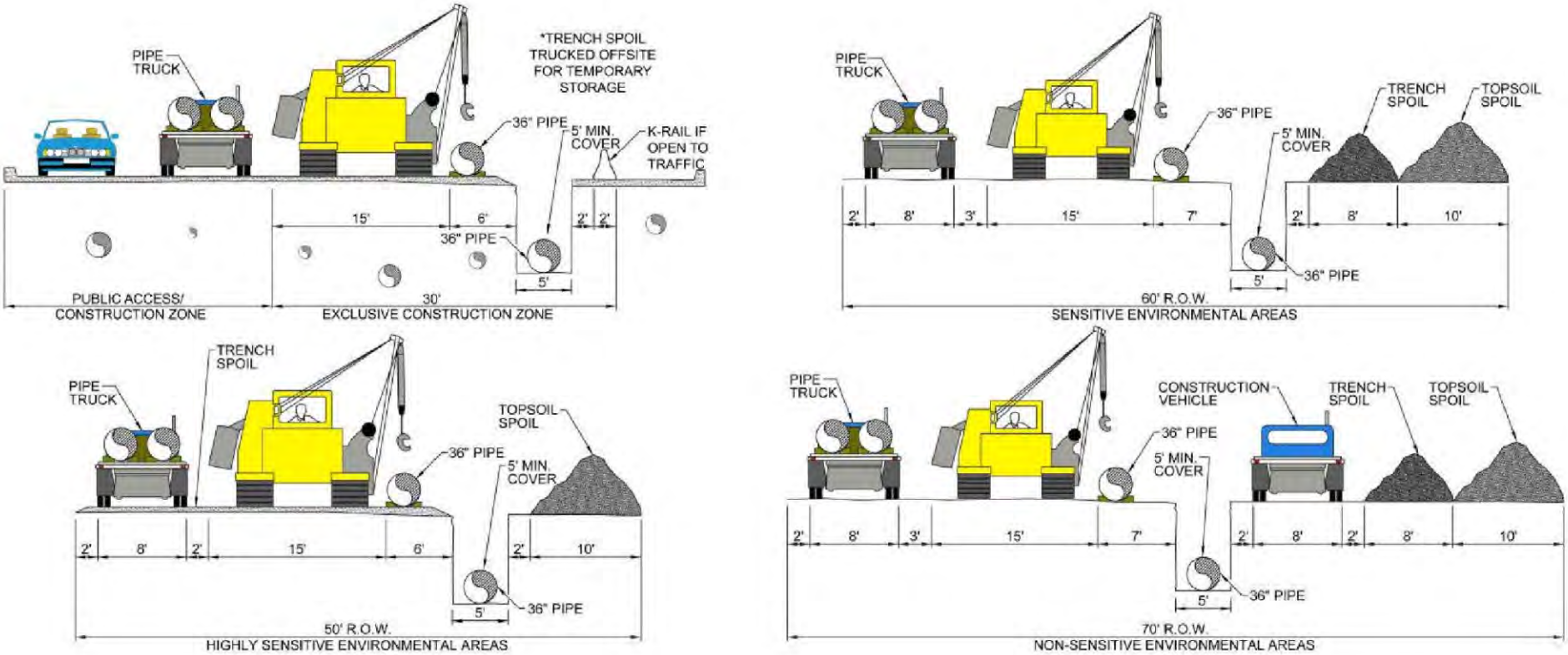
[6] Due to their inactive status, Aera removed water wells Bonetti-WS1 and McCroskey-WS11 from the Project design. Water well McCroskey-WS12 as well as one or two new freshwater wells would provide all fresh water needs for the Project.

Additional workspace would be required to facilitate specialized construction techniques, such as horizontal directional drill, horizontal bores, and drainage crossings. The extra workspace would be used to store spoil and equipment needed to complete construction in areas where specialized techniques are required.

2.6.5.2 Construction Methodology of Natural Gas Pipeline

Construction and installation of the natural gas pipeline would be achieved through a combination of conventional trenching, jack-and-bore, and horizontal direction drill methods (Figure 2-20, Typical Pipeline Construction, Figure 2-21, Typical Jack and Bore Work Area, Figure 2-22, Typical Horizontal Directional Drill [First Pass], and Figure 2-23, Typical Horizontal Directional Drill [Second and Third Pass]). The sequence of construction activities for the natural gas pipeline component of the Project is summarized below. Construction of the natural gas pipeline would occur in Phase I and is scheduled to take approximately 5 to 6 months.

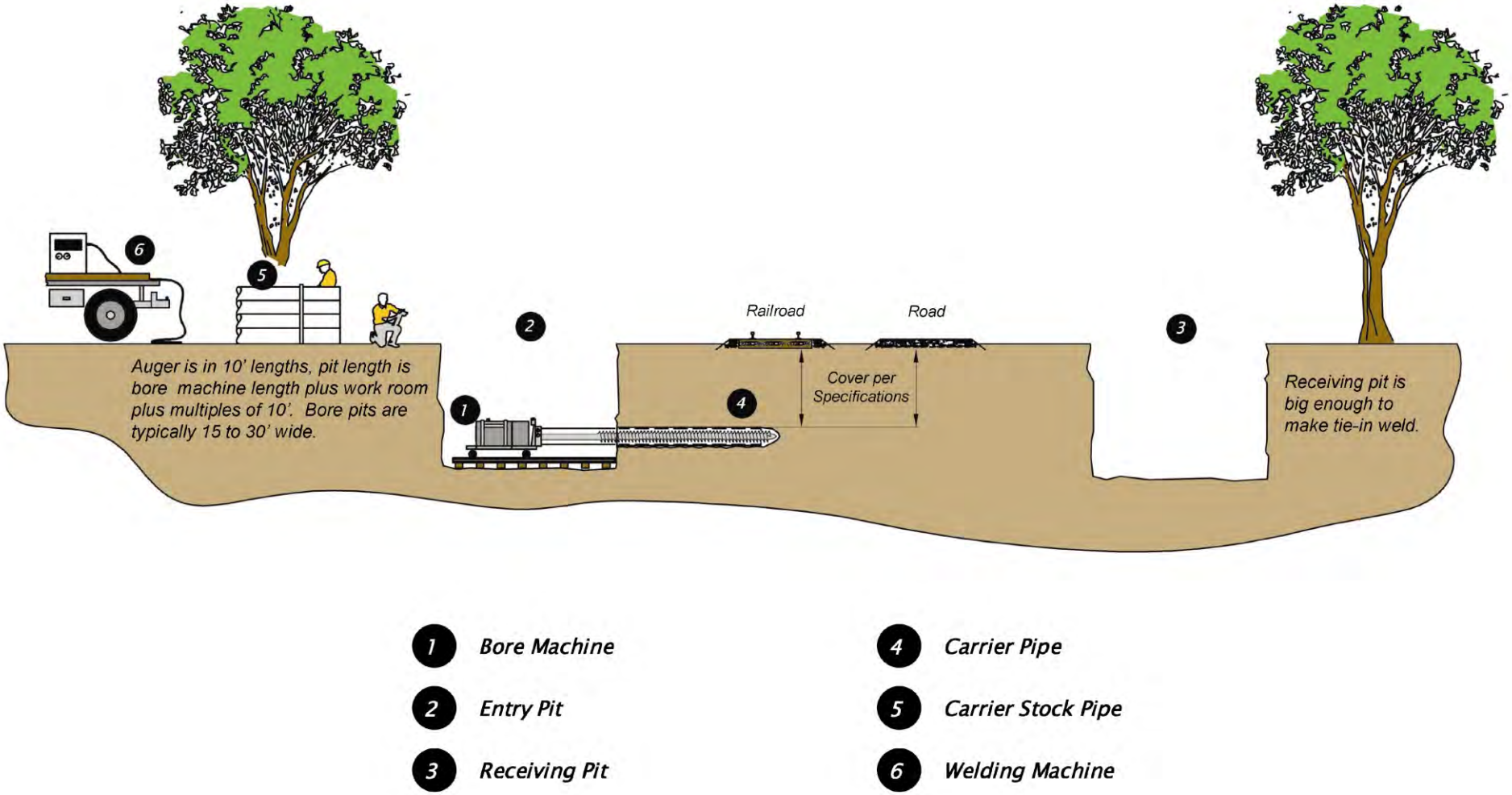
- **Notifications.** Notifications would be made to local permitting agencies, all property owners and tenants within 300 feet of the Project boundary, emergency response providers, and the general public (via signage, etc.).
- **Mobilization and Staging.** Prior to construction, the contractor would mobilize the site and establish staging areas for materials and equipment storage. Construction equipment would be staged along the route and would progress with the pipe installation.
- **Surveying, Staking and Flagging.** The centerline would be marked at line-of-site intervals, at points of intersection (including offset stakes marking the edges of the ROW), and at all known underground facilities. In addition, any environmentally sensitive areas (i.e., biological, cultural, and/or hydrological resources) would be clearly marked.
- **Clearing and Grading.** The majority of the temporary construction easement occurs along the previously disturbed road shoulders. Where necessary, existing vegetation would be cleared and the shoulder surface within the construction ROW would be smoothed to provide safe and efficient operation of construction equipment.
- **Hauling and Stringing.** The pipe would be hauled by truck to one of the staging areas where it would be offloaded by cranes and loaded onto stringing trucks to be delivered to the construction ROW.
- **Trenching.** The typical trench would be approximately 5 feet deep and between 2 and 5 feet wide. Excavated soils may be preserved and used as backfill materials at the site of origin. Spoil piles would be placed along the trench in areas where a temporary construction easement is available or along the roadway or road shoulder. At this time, complete road closures are not anticipated. However, temporary lane or roadway closures would be determined by the County Public Works Department. If pre-approved sections of the public roadway are temporarily closed in sections to accommodate staging of the spoil within the roadway, detours would be established in accordance with SoCalGas's Traffic Control Plan. Materials deemed unsuitable for backfill would be disposed of offsite in accordance with all applicable regulations.
- **Horizontal Directional Drilling.** Horizontal directional drilling (HDD) is a highly specialized boring technique that is often used when trenching or excavating is not practical and would likely be used to install the pipe beneath U.S. Highway 101 and Cat Canyon Creek as well as various road and culvert crossings in the proposed Project area. HDD is a trenchless method of pipeline installation using a surface-launched drilling rig that installs the piping via a pre-drilled, arc-like bore hole that can occur at depths of less than 10 feet to over 30 feet *below the ground surface or creek bed*. HDD depths would be engineered



Source: Aera, 2016.

Figure 2-20

Typical Pipeline Construction

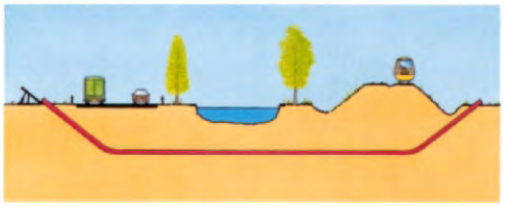


Source: Aera, 2016.

Figure 2-21

Typical Jack and Bore Work Area

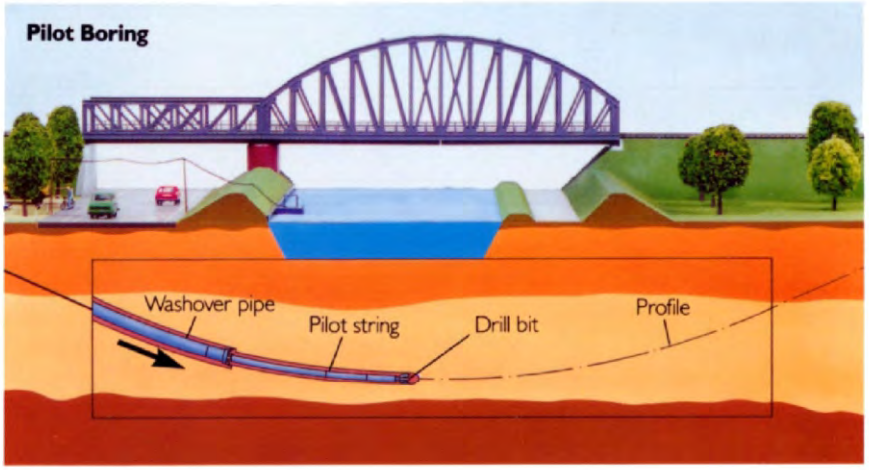
Road, River, Canal and Rail crossings



Typical Application

The Technique...

Drilling the profile
A small diameter pilot hole is drilled to a pre-determined path using a mud-motor or jet bit on the end of the pilot string. The pilot string is drilled up to 80 meters in length, then the washover pipe is advanced until it is approximately 30 meters behind the drill bit. Alternate pilot string and drilling operations take place until the exit point is reached.



First Pass

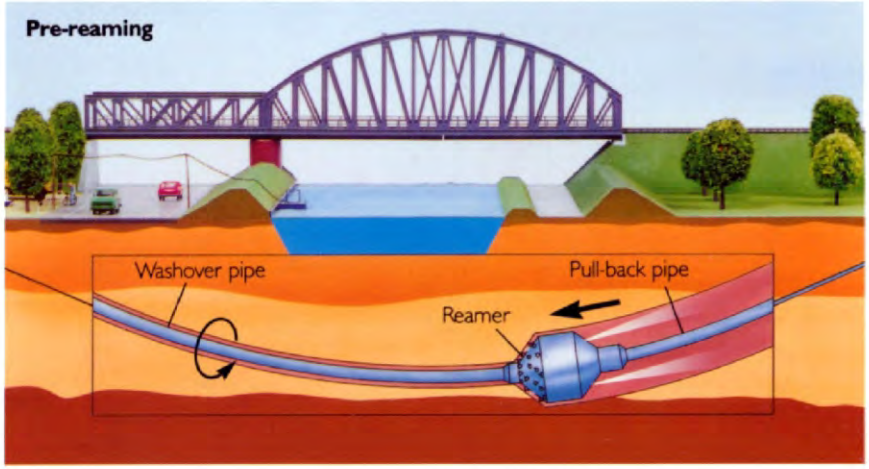
Source: Aera, 2016.

Figure 2-22

Typical Horizontal Directional Drill (First Pass)

Enlarging the hole

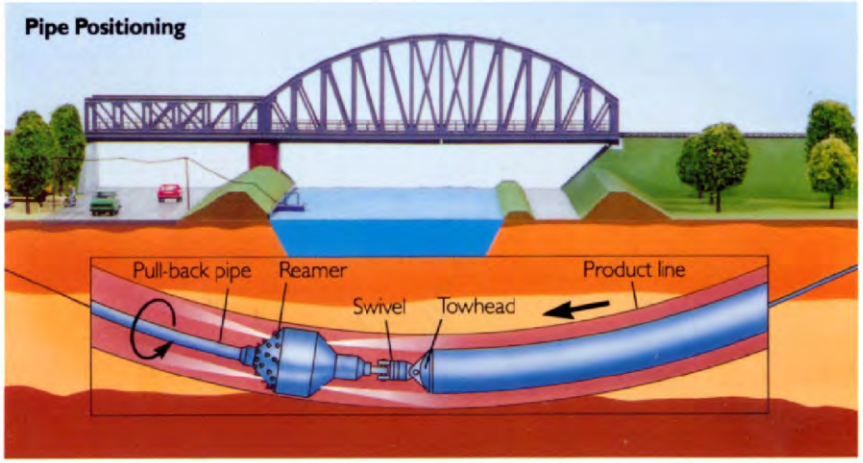
Pre-reaming operations are carried out to enlarge the drilled hole to a size suitable for accepting the product pipe. Pull-back pipe is added behind the reamer. Depending upon the pipe diameter to be installed several pre-reamed operations may be necessary, each progressively enlarging the hole.



Second Pass

Installing the Pipe

The pull-back is connected to a 'cleaning' reamer which in turn connects to a swivel joint, (to prevent pipe rotation) that is attached tot he pipeline towhead. The drill rig is then used to pull the product pipe into the preformed hole.



Third Pass

Source: Aera, 2016.

Figure 2-23

Typical Horizontal Directional Drill (Second and Third Pass)

to reduce the likelihood of drilling fluid release through subsurface fractures and to accommodate the 8-inch diameter of the pipeline. The HDD process would utilize an entry pit and an exit pit to contain the drilling mud, and the SoCal Gas Contractor shall be required to have a Drilling Fluid Monitoring and Mitigation Plan and to monitor pressure. In general, the work area required on the entry site would be approximately 50 feet by 200 feet, while the exit site would require a work area of approximately 50 feet by 100 feet. In addition, an approximate 10-foot by 1,650-foot temporary work area on the exit side of the drill would be required to string and weld the pullback pipe. The HDD drilling and associated pipeline installation at the U.S. Highway 101 crossing is anticipated to take 8 weeks to complete. The HDD crossing at Cat Canyon Creek is anticipated to take 6 weeks to complete.

- **Jack-and-Bore.** Jack-and-bore tunneling would be utilized at road crossings culverts, where required. This methodology is used for horizontal pipeline construction and entails the excavation of pits on either side of the crossing and use of a boring machine with a cutting 'head', auger and casing. The auger and casing are pushed behind the 'head' as it cuts through the ground. The auger caries the debris back to the pit as the head cuts. Jack-and-bore horizontal tunneling is anticipated to occur at the intersection of East Clark Avenue and South Bradley Road, and take approximately 10 days to complete at each location. Additional locations may be added based on circumstances that are unknown at this time, such as utility conflicts or requirements imposed by either the County of Santa Barbara Public Works Dept. or Caltrans. Typical horizontal bores are 10 feet deep and require entry pits of approximately 15 feet by 40 feet and receiving pits of approximately 10 feet by 15 feet. In any location where Jack and Bore is used, there is only one entry pit and one exit pit.
- **Pipe Bending, Welding and Coating.** Once the trench is excavated, any bends that are required (i.e., to avoid substructures or changes in the alignment) can be determined, measured, and completed for installation. When necessary, the pipe would be bent in the field utilizing track-mounted pipe-bending equipment. Pipe bending is only applicable in areas where trenching is utilized. New natural gas pipeline segments would be inspected to locate and repair any faults or voids in the natural gas pipeline coating prior to being lowered into the trench. In areas were the pipe is joined within the ditch, "bell holes" would be dug at each pipe joint to facilitate access for welding and joint coating application. These welds would typically be made in the ditch, with the pipe at its final elevation and alignment. Welding and Coating will apply to all areas throughout the project.
- **Weld Inspection.** Although the applicable regulations only require radiographic inspection of a certain percentage of the circumferential welds, all welds would be radiographically inspected in accordance with state and federal welding requirements. 100% Radiographic Weld Inspections shall be utilized for this gas pipeline construction project. All radiographs would be recorded and interpreted for acceptability in accordance with American Petroleum Institute 1104. All rejected welds would be repaired or replaced as necessary and re-radiographed. The inspection reports would be kept for the life of the natural gas pipeline.
- **Line Lowering, Backfill and Compaction.** For conventional open trench segments, the welded pipe segments or individual pipe lengths would be lifted and lowered into the trench by sideboom tractors. The native material excavated from the natural gas pipeline trench would either be reused as backfill, or in the case that the soils were deemed in appropriate to use as backfill, the excavated material would be disposed offsite at an approved facility, and clean, engineered fill would be imported for backfill. Required backfill material would be compacted with compaction rollers and/or hydraulic tampers and undergo compaction testing to ensure that all trench locations are compacted in accordance with standard engineering practices and permit requirements. In areas where topsoil segregation is required, the topsoil would then be restored to its original grade and contour. All trenches would either be fenced, backfilled, or covered with steel plates at the end of each workday.

- **Aboveground Equipment Installation.** The majority of aboveground equipment would be pre-fabricated at a staging area and then transported to the respective locations for final assembly and tie-in to the natural gas pipeline facilities. Valve and meter set assembly locations would be either paved or graveled. After installation, all above-grade piping and equipment would be painted and the valve would be enclosed by a chain-link fence.
- **Hydrostatic Testing.** In accordance with U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) standards, the entire natural gas pipeline and the HDD segments would undergo hydrostatic testing prior to operation by pumping up to 150,000 gallons of water into the test sections, pressurized to design-test pressure, and maintained at that pressure for a minimum of eight hours. Water to be used for hydrotest shall be from local water systems. Discharged water shall be stored into baker tanks to be held for testing. After results of the samples are analyzed, the water may be used for dust control at the project site or used for additional testing on other pipeline segments. If quantity of water exceeds the storage capacity of the baker tanks on site, discharge shall be to local water sewer systems based on approval from local municipalities or this water may be sent to a local recycling facility. The Storm Water Pollution Prevention Plan (SWPPP) prepared by SoCalGas would also include Best Management Practices in case the hydrotest is not successful initially.
- **Pigging.** Pipeline pigs are devices that are inserted into and travel throughout the length of a pipeline driven by a product flow to perform functions, such as cleaning or dewatering and provide information on the condition of the line, as well as the extent and location of any problems. After the natural gas pipeline has been hydrostatically tested and dewatered, the contractor would run several utility pigs of various types to remove as much water as possible and any remaining small debris from within the natural gas pipeline.
- **Erosion and Sediment Control.** A SWPPP would be prepared by SoCalGas to cover construction activities associated with installation of the natural gas pipeline. This plan would be prepared in accordance with the Regional Water Quality Control Board guidelines and other applicable Best Management Practices. Implementation of the plan would help stabilize disturbed areas and waterways and would reduce erosion and sedimentation. The plan would designate Best Management Practices that would be followed during construction activities.
- **Cleanup and Restoration**. All construction material and debris would be removed and disposed of at appropriate landfills or recycled. Clean up and Restoration will be ongoing throughout the project and when an active site is completed, the area shall be restored to surface grade. In upland areas, the ROW would be regraded to its approximate pre-construction contour and stabilized or restored to pre-construction conditions, as specified by the property owner and in compliance with all relevant permits. All staging areas and temporary extra workspaces would be recontoured to pre-construction conditions and would be stabilized or restored in accordance with prearranged landowner requirements and in compliance with all relevant permits. For certain areas as part of the restoration activities, soil may be decompacted and reseeded in accordance with the landowners' requests and applicable permits. All paving repairs would be made in accordance with the current city and/or County requirements. As a final step, the route within unpaved portions of the roadway shoulder or private ROW would be marked with approximately five-foot-high pipeline markers placed in accordance with PHMSA standards.
- **Operations and Maintenance**: Maintenance of natural gas pipeline and auxiliary facilities will continue to be performed under CFR 49 and GO 112.

2.6.6 PG&E Electrical Power Line Construction

As described in Section 2.5.6.2 (PG&E Electrical Power Line Interconnection), PG&E would construct, operate, and maintain a new approximately 0.3-mile, 115-kV power line to the Aera-owned substation

located at the Project site. The estimated permanent disturbance of the 115 kV electrical interconnection would be 0.01 acre with 2.1 acres of temporary disturbance and an estimated cut and fill volume of 5.6 cubic yards. To support the major drilling and construction efforts, electrical connections are anticipated be in place prior to significant field activities.

2.6.6.1 Access and Staging Areas for Electrical Power Line Interconnection

Access. Primary access to the power line interconnection site would be located at 6516 Cat Canyon Road. The existing Cat Canyon Road consists of approximately 20-foot-wide pavement from Palmer Road. The Project would also include improvements to a secondary access located along Long Canyon Road, on the eastern boundary of the Project site. Improvements to the existing dirt access road may include grading and rocking of the access road as well as periodic maintenance to the road, as needed.

Temporary Staging, Laydown, and Work Areas. Construction of the power line interconnection would be completed by PG&E or a designated contractor. The new steel monopole structures would require permanent concrete foundations approximately 6 feet in diameter and up to 35 feet deep. Construction would involve temporary ground disturbance around each new power pole location (approximately a 50-foot radius) as well as temporary ground disturbance associated with access to each pole location (approximately a 15-foot-wide access route). All new poles and access thereto would be located within existing oil field production areas or along a dirt road. Pole work areas would likely be located approximately every 300 to 350 feet within the future right-of-way at new pole locations. Where final design allows, power pole work areas would overlap. Final design would determine final power pole locations. Temporary staging and laydown areas may also be needed for the construction of the interconnection facilities.

2.6.6.2 Construction Methodology for Electrical Power Line Interconnection

Substation Improvements. Modifications may be required at the PG&E-owned substations (i.e. Sisquoc or Palmer Substations). Work at both substations would occur within the existing PG&E substation fence line. Site preparation and removal of some existing structures may be a part of construction.

Powerline Removal/Construction. As discussed in Section 2.5.6.2 (PG&E Electric Power Line Interconnection), the new 115 kV power line would be supported by up to approximately 10 tubular steel poles or light-duty steel poles. Approximately 5 structures would be installed either between or in place of the existing alignment along the existing Sisquoc–Santa Ynez 115 kV Power Line. Approximately 5 structures would be installed along the new 115 kV power line to the proposed Aera-owned 115 kV substation. Of those 10 poles, approximately 5 existing single-circuit wood poles may be removed. For a temporary period during construction of the line, PG&E would move one to two spans (approximately 1,000 feet) to the south of the existing alignment using 6 temporary wood poles to keep the line in service but away from the construction area.

Pole installation would consist of the following basic steps:

- Deliver new pole at pole site;
- Auger new hole using line truck attachment or hand dig if the line truck cannot access the site;
- Pour concrete foundation for tubular steel poles;
- Install bottom section by line truck, crane, or helicopter;
- Install top section by line truck, crane, or helicopter; and
- Install switches where necessary. There may be up to approximately three supervisory control and data acquisition operable or other switches at the point of interconnection and elsewhere.

Once poles are erected, conductor would be strung from conductor pull and tension sites at the end of the power line interconnection alignment. The average distance is 4,000 feet between pull and tension sites. Power line construction would generally follow the same procedures as outlined in Section 2.6.4.2 (Intra-Field Electrical Distribution). Prior to pulling and tensioning, workers would install temporary guard structures where the line crosses Cat Canyon Road to prevent sock line or conductors from dropping onto the road.

Power Line construction and substation improvements would occur during Phase I and are anticipated to take approximately 2 to 3 months.

Erosion and Sediment Control. A Storm Water Pollution Prevention Plan would be prepared by PG&E to cover construction activities associated with installation of the electrical power line. This plan would be prepared in accordance with the Regional Water Quality Control Board guidelines and other applicable Best Management Practices. Implementation of the plan would help stabilize disturbed areas and waterways and would reduce erosion and sedimentation. The plan would designate Best Management Practices that would be followed during construction activities.

Cleanup Activities. All construction debris would be picked up and hauled away for recycling or disposal during construction. A final survey would be conducted to ensure that clean-up activities have been successfully completed as required. Access roads would not be re-vegetated; they would continue to be used for operations and maintenance. Other than work to establish tree-to-line clearances and radial clearances at the base of the power poles, vegetation clearing and grading are not anticipated for any staging areas, pull and tension sites, or pole site work areas; therefore, no restoration would be expected.

Operations and Maintenance: Maintenance of power line interconnection facilities would continue to be performed as follows:

- Inspections would be performed annually by existing local staff;
- A detailed inspection would be performed by existing local staff every two years, with an air patrol inspection being performed in between, as outlined in PG&E's Electrical Transmission Prevention Maintenance Manual (2011); and
- A single inspector (existing local staff) would patrol the line as part of the 115 kV power line detailed inspection and aerial patrols.

One the new power line is built and energized, PG&E's existing local maintenance and operations group would assume inspection, patrol, and maintenance duties as needed. No additional staff would be required after the new line work is completed. Existing operation and maintenance crews would operate and maintain the new power line equipment as part of their current power line operation and maintenance activities.

2.6.7 Construction Personnel and Traffic

Equipment and personnel requirements would vary throughout the course of any given year and across the life of the Project depending on the construction activities underway. However, it is estimated that the peak construction workforce would occur during Phase I with a total of 329 people.

Drilling rigs would operate 24 hours per day while drilling, and the proposed injection and production wells are expected to take approximately 6 to 9 days to complete. Drilling crews consist of 6 to 7 contractors who would typically be onsite for 12-hour shifts, one starting at noon and the other starting at midnight.

At full buildout (Phase II), the operational aspects of the Project would require a total of 115 personnel. Approximately 40 operating personnel would be comprised of staff and hourly worker positions which would be supplemented with approximately 75 additional contractor personnel for well and equipment maintenance, on-going new construction activities, infrastructure and operations support, and materials delivery. Appendix B provides a listing of the permanent personnel requirements and contract services for surface, subsurface, and drilling support for the operational phase of the Project.

During the years of peak Project operation in Phase II, the Project is anticipated to generate approximately 531 average daily vehicle one-way trips per day. Of these, 198 are tanker truck trips, 18 are non-tanker truck trips (e.g., bulk material and waste deliveries), and 315 are employee vehicle trips. This includes 10 trips occurring during the a.m. peak hour and 89 trips occurring during the p.m. peak hour. During construction, truck trips would be variable, but average daily heavy-duty truck trips would not exceed 28 one-way trips per day.

It is expected that more than 50 percent of construction personnel would arrive by bus, van pool, or ride sharing. Parking for workers accessing the jobsite through these means would be in existing, established, and lawful parking areas and spaces in the public and private domain. Worker parking on site would be on Project property, using designated areas such as staging areas and existing and new well pads as they are constructed.

2.7 Produced Oil Transport

As described in Section 2.5.9 (Produced Oil Transport), during both phases of operation, light crude would be imported by tanker truck from Aera's Belridge Producing Complex, approximately 140.4 miles away, and blended with the produced oil. The resulting blend would be exported back to Belridge (see Figure 2-15, Regional Roadway Map). The proposed Project is expected to produce approximately 10,000 bpd, which would require 3,281 bpd (21 truckloads) of imported light crude from Belridge and then approximately 13,300 bpd of blend being transported back to Belridge.

That is, during the years of peak Project operation in Phase II, a total of 95 trucks would arrive at the Project from Belridge each day. Of that total, 21 trucks would arrive with light crude and then return to Belridge with blend. Another 74 trucks would arrive empty from Belridge and then return to Belridge with blend. Therefore, approximately 22 percent of the laden truck trips would be roundtrip (produced oil from the Project site delivered to Belridge and light crude from Belridge backhauled to the Project site) and 78 percent of the laden truck trips would be one-way (produced oil from the Project site delivered to Belridge with no backhaul).

The tanker trucks would be new, Compressed Natural Gas (CNG) trucks with California Air Resources Board (CARB)-certified Ultra Low NOx emission engines that are 95 percent lower than the United States Environmental Protection Agency (USEPA) emissions standard and would provide about an 80 percent reduction from standard diesel engine NOx emissions. These CNG trucks would be quieter than comparative diesel trucks and would be equipped with state of the art safety technologies, including GPS monitoring, driver safety performance tracking, and video.

The Project tanker fleet would refuel at commercial CNG and or RNG fueling stations, located in the Bakersfield and Santa Maria areas, and along the route. Each CNG truck carrying a full load of crude (approximately 155 barrels) would refuel every 10 to 12 hours or approximately 400 miles.

As discussed in Section 2.6.7 (Construction Personnel and Traffic), during the years of peak Project operation in Phase II, there would be a peak of 190 daily one-way tanker truck trips. All tanker trucks would

deliver and reload at the central processing facility only, via the improved main site entrance. The three local route options that would be used by trucks to and from the site are discussed in Section 2.5.8 (Site Access, Access Roads, and Staging) and shown on Figure 2-14 (Proposed Trucking Routes to Highway 101 Detail).

2.8 Oil Field Operation, Maintenance, and Abandonment

2.8.1 Operations and Maintenance

All facilities/equipment would be operated, maintained and inspected in accordance with the applicable requirements of DOGGR contained in California Code of Regulations Title 14 and Santa Barbara County requirements. These regulations specify the types and frequencies of safety inspections and maintenance to be performed. Records documenting compliance with these requirements would be maintained on site and would be periodically reviewed by Aera personnel to ensure compliance. In addition, safety and compliance inspections/audits of the facilities are performed on a regular basis by DOGGR personnel.

2.8.1.1 Personnel and Facility Safety Protocol/Emergency Response

The following plans would be developed for facility operations as required by State and County regulatory requirements:

- Spill Contingency and Safety Plans
- Emergency Action Plan and Fire Protection Plan
- Emergency Response Plan

2.8.1.2 Waste Handling and Storage

Project well drilling and operations would utilize hazardous and non-hazardous chemicals typical of an oil production facility such as: oil products such as gasoline, diesel and road mix; plant chemicals such as corrosion and scale inhibitors, flocculants; field chemicals such as corrosion and scale inhibitors; paints, epoxies, and grouts; lab chemicals; operator, mechanic and welder supplies; caustic for use at production group station and water cleaning plant; produced sand (export); sulfur cake (export); SulfaTreat media; and spent SulfaTreat media (export) and others.

Field operations would generate the multiple waste streams, each of which would be managed in accordance with applicable Federal, State and local laws, regulations and ordinances. Appendix B provides additional information on average quantities of anticipated waste.

2.8.1.3 Site Security

Public access to the Project site is restricted due to the presence of a locked electronic gate located off of Cat Canyon Road, a locked manual gate on the east side of Long Canyon Road, and a locked manual gate on the west side of Long Canyon Road. The electronic gate is equipped with a “Knox Box” key for emergency response personnel and both manual gates are also equipped with combination padlocks that have been provided to Santa Barbara County Fire Department personnel for access to the property from either entrance.

The Project would maintain similar security at these existing entrances, but would also add a new main entrance from Cat Canyon Road, approximately 300 feet north of the existing entrance, that would also have an electronic gate. In addition, a portion of the Project site east of Long Canyon Road, which is pro-

posed as a conservation easement, may eventually provide some public access, consistent with the goals of conservation and conservation education.

During initial operation, the central processing facility would be provided with 24-hour surveillance. After the systems are mature, surveillance may be reduced to daylight hours only. Night surveillance would consist of driving through the field, including the central processing facility and other plant areas and responding to down equipment, pipeline leaks, storm water management issues, or property security issues.

2.8.2 Well Workover and Replacement

2.8.2.1 Well Workover

After a well is completed and produced for some time, it may require a workover. A workover is any operation performed on a well to restore or increase its production. In general, workovers are done to:

- Control water or gas production in an oil well;
- Prevent water inflow from the reservoir;
- Repair mechanical problems;
- Remove scaling mineral deposits that clog flow using acidizing[7]; and
- Improve production.

Well servicing (i.e., pulling or replacing a pump, rods, or tubing) would typically be performed during daytime hours only and would normally take 5 days per well. A well workover (i.e., well recompletion type work) may occur 24 hours per day, 7 days per week depending on the particular job. A workover would typically require 15 days per well.

Well-servicing operations would be conducted primarily by contract services and would include one well servicing rig with a crew of four personnel for well workover and maintenance activities through the end of Phase I. A second well servicing rig and crew of four personnel would be added in Phase II as the Project well drilling program progresses.

2.8.2.2 Well Replacement

Over the life of the Project, there may be the need for up to 30 replacement wells (i.e., approximately one percent per year replacement rate). Any “in-kind” replacement wells would be drilled on existing pads, and accessed by existing roads, thus would not increase the Project’s disturbance footprint. Any replacement wells would not increase the overall total number of wells (296), because they would only be drilled once the existing well to be replaced is plugged and abandoned in accordance with DOGGR standards.

2.8.3 Well Abandonment

If, following initial drilling, testing, and production, any of the new 296 wells prove to be uneconomic, they would be plugged and abandoned in accordance with DOGGR and Santa Barbara County Petroleum Division standards. Likewise, any constructed production wells deemed to be at the end of their productive life would be plugged and abandoned according to DOGGR and Santa Barbara County Petroleum Division standards.

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[7] Well workovers involving the removal of deposits/scale (i.e., limestones and dolomites) on the screen at the bottom of the well involve the injection of acids down through the tubing inside the casing of the well at low pressures that do not fracture rock. When the acid reaches the well screen, it flows through the screen and into the pore spaces of the reservoir rocks near the well. This process is referred to as “acidizing”.

Aera will comply with California Senate Bill 1763 that requires the operators of oil, gas, injector, disposal and observation wells in the State of California to develop a process to abandon the idle wells under their control. In addition, Aera will comply with Santa Barbara County Petroleum Code (Chapter 25) requirements regarding well abandonment. Decommissioning of associated facilities is described in Section 2.9 (Decommissioning).

2.8.4 Natural Gas Pipeline and Electrical Transmission Operations

The natural gas pipeline would be operated in accordance with the pipeline safety requirements of PHMSA contained in Title 49 of the Code of Federal Regulations and the requirements of the CPUC.

Likewise, the 115 kV power line interconnection would be maintained in a manner consistent with CPUC General Order 95,[8] as applicable. PG&E would inspect the overhead facilities in a manner consistent with CPUC General Order 165, a minimum of once per year via ground and/or aerial observation.

2.9 Decommissioning

2.9.1 General Decommissioning Procedures

Based on current projections, Aera estimates that the Project would span approximately 30 years, but may extend to 50 years or more. At such a time that Aera determines that its use of the East Cat Canyon properties as an oil producing facility has come to an end, Aera would make a determination as to divesture or decommissioning of the Project site facilities and wells. Surface and subsurface abandonment activities would begin after all applicable permits and notifications are completed. Typically, decommissioning of an oil field property includes the following:

- Shut-down and bleed down of facilities and pipelines;
- Removal of residual oil, gas, and water from tanks, pipelines, and vessels;
- Plugging and abandonment of oil wells;
- Removal of surface equipment at well sites;
- Isolation and removal of utility systems (water, electrical service, and natural gas);
- Demolition and removal of intra-facility pipelines, tanks, vessels, and other equipment;
- Demolition of onsite buildings and structures;
- Demolition and removal of concrete foundations and slabs;
- Assessment and remediation of contaminated soils; and
- Re-grading and re-seeding of facility and infrastructure areas.

Permits would be required for decommissioning activities from the County of Santa Barbara and other regulatory agencies as needed, including but not limited to the U.S. Army Corps of Engineers, Central Coast Regional Water Quality Control Board, California Department of Fish and Wildlife, DOGGR, and the Santa Barbara County Air Pollution Control District.

2.9.2 Santa Barbara County Petroleum Code

The County of Santa Barbara has enacted regulations under the County Petroleum Code [Chapter 25 (Ordinance #4794)] that regulate the abandonment and removal of oil and gas facilities. The Petroleum Code addresses well abandonment and lease restoration requirements and requires submittal of a lease restoration plan to the Petroleum Office prior to the abandonment of the last well on a lease. Consistent

[8] http://cpuc.ca.gov/gos/GO95/go_95_rule_35.html.

with both County and State Division of Oil, Gas, and Geothermal Resources (DOGGR) regulations, wells would be plugged and abandoned and support equipment removed. Per the Petroleum Code Sections 25-32 (Abandonment procedure) and 25-33 (Removal of equipment), graded pads would be cleared of debris and any facility items including tanks, vessels, and pipelines. Per County Land Use Development Code (LUDC) Section 35.52.050.B.l upon well abandonment, the site would be recontoured, reseeded, and landscaped to approximate original conditions or other conditions as approved by the County.

At the completion of the Project site's oil producing activities, Aera is committed to restoring the Project site per Santa Barbara County "lease restoration procedures", as outlined in Chapter 25 – Petroleum Code (Sec. 25-31). Prior to the abandonment of the last well on the Project site, Aera would file with the petroleum administrator a plan, for approval, to restore the Project site to a condition in conformance with state, county, and local ordinances. Aera would coordinate with the County petroleum unit along with County grading, planning and development, the fire department and other agencies, as required, to ensure all lease restoration requirements have been addressed. Soil remediation, if necessary, will occur as directed by DOGGR and/or the County.

The lease restoration plan may include the following measures/procedures, or equivalent:

- Equipment removal.
- Removal of flow lines and utilities.
- Building removal.
- Remediation of sumps, pits and areas of soil contamination.
- Removal of roads and well sites.
- Facilities to be left in place.
- Completion.

2.10 Applicant Proposed Avoidance and Minimization Measures

Aera's application contained Avoidance and Minimization Measures (AMMs) to minimize the Project's environmental impacts in a manner consistent with applicable rules and regulations. Aera, PG&E, and SoCalGas proposed to implement these measures during the design, construction, and operation of the proposed Project in order to avoid or minimize potential environmental impacts.

Aera and PG&E's proposed AMMs, which are listed in Appendix C and in each environmental issue area section, are considered part of the Proposed Project and are considered in the evaluation of environmental impacts (see Section 4, Environmental Analysis). In some cases, mitigation measures presented in Section 4 either expand upon or add detail to the AMMs presented in Appendix C as necessary, to ensure that potential impacts would be reduced to less than significant levels. County and CPUC approval would be based upon Aera and PG&E adhering to the proposed Project as described in this document, including this project description and the AMMs, as well as any adopted mitigation measures identified by this EIR.

2.11 Alternatives

2.11.1 Description of Alternatives and Screening Analysis

Section 15126.6(a) of the State California Environmental Quality Act (CEQA) Guidelines states that an Environmental Impact Report (EIR) "shall describe a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project, but would avoid or substantially lessen any of the significant effects of the project, and evaluate the comparative merits of the alternatives." Further, an EIR need not consider every conceivable alternative to a

project. Rather, it must consider a reasonable range of potentially feasible alternatives that will foster informed decision making and public participation. An EIR is not required to consider alternatives that are infeasible. The CEQA Guidelines state that factors that may be considered when determining the feasibility of alternatives are "site suitability, economic viability, availability of infrastructure, general plan consistency, other plans or regulatory limitations, jurisdictional boundaries (projects with a regionally significant impact should consider the regional context) and whether the proponent can reasonably acquire, control, or otherwise have access to the alternative site (or the site is already owned by the proponent)" [CEQA Guidelines Section 15126.6(f)(1)].

Additionally, the No Project Alternative must be analyzed. The EIR must explain the rationale for selecting the alternatives to be discussed, identify those that were not carried forward because they were infeasible, and briefly explain why these were not carried forward. The "environmentally superior" alternative to the Project must be identified and discussed (see Section 5, Comparison of Alternatives). If the environmentally superior alternative is the No Project Alternative, the EIR must identify an additional "environmentally superior" choice among the other project alternatives.

As presented below, a variety of alternatives to the Project were considered to determine potential alternatives which might produce fewer significant impacts, or reduce the severity of those significant impacts than the proposed Project, including the No Project Alternative. Possible alternatives were assessed as to whether they would satisfy the following:

- The alternative is technically feasible;
- The alternative would avoid or substantially lessen any of the significant impacts of the proposed Project; and
- The alternative would attain most of the basic proposed Project objectives.

Alternatives considered included the No Project Alternative and those associated with reduced footprints or different pipeline alignments. As listed below, alternatives considered, but not carried forward for further analysis are presented in Section 2.11.2. The No Project Alternative is presented in Section 2.11.3 and alternatives carried forward for evaluation in Section 4 (Environmental Analysis) are presented in Section 2.11.4. An alternative comparison is provided in Section 5.

- **Section 2.11.2. Alternatives Considered but not Carried Forward**
  - Section 2.11.2.1. Alternative Sites
  - Section 2.11.2.2. Alternative Heating Technologies
  - Section 2.11.2.3. Conventional Drilling Alternative
  - Section 2.11.2.4. Renewable Energy Sources Alternative
  - Section 2.11.2.5. Natural Gas Pipeline Alternative
- **Section 2.11.3. No Project Alternative**
- **Section 2.11.4. Alternatives Carried Forward**
  - Section 2.11.4.1. Alternative 1: Reduced Footprint Alternative
  - Section 2.11.4.2. Alternative 2: Oak Avoidance Alternative
  - Section 2.11.4.3. Alternative 3: Phillips 66 Pipeline Alternative
  - Section 2.11.4.4. Alternative 4: Plains Pipeline Alternative
  - Section 2.11.4.5. Alternative 5: Natural Gas Pipeline Reroute Alternative

2.11.2 Alternatives Considered but not Carried Forward

2.11.2.1 Alternative Sites

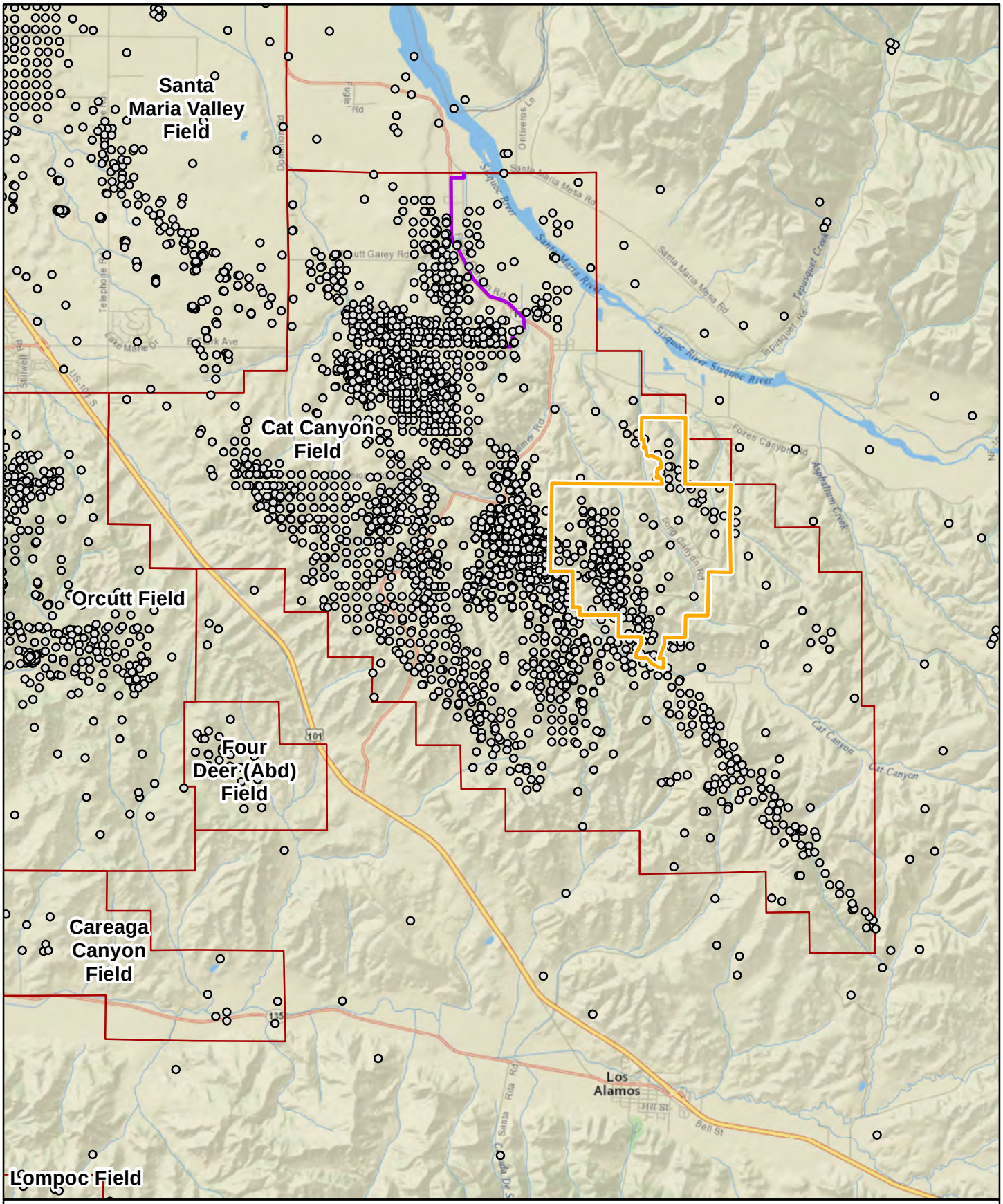
The use of alternative site locations was considered, but was focused on enhanced oil and gas development within existing oil and gas fields within northern Santa Barbara County because of potential availability of additional oil and gas subsurface resources (see Figure 2-24, Alternative Oil and Gas Development Sites). This alternative concept has merit in that it would satisfy the basic Project objectives and existing oil and gas fields are located primarily on lands within appropriate zone districts which allow oil and gas development. However, this alternative concept was not carried forward for detailed analysis because it was not considered feasible since it is unlikely that it would avoid or substantially reduce environmental impacts compared to the proposed Project location. Further, new lease agreements would need to be developed with the property owners or agencies with jurisdiction over the alternative sites. Finally, as discussed in Section 3.0 (Cumulative Scenario), oil production is already proposed and currently exists for many of the subject sites (see Table 3-1, Cumulative Development Summary). Therefore, the ability to obtain site control is speculative.

2.11.2.2 Alternative Heating Technologies

Public comments received during scoping suggested alternative methods to steam injection for heating the subsurface oil producing zone, including direct heating, radio frequency/microwave heating, and microbial and surfactant stimulation technologies. These alternative heating technologies are each described as follows:

- **Direct Heating.** This technology would use slow in-situ heating of the heavy crude using electrical resistance heating (ERH) techniques applied directly into the target area. The process would be conducted at a low temperature and pressure, but over a longer time than steam injection. Previous studies have noted that poor efficiency in electric power generation was a major drawback to the ERH method. Therefore, it has been considered as a preheat for more conventional thermal processes rather than developed as an independent recovery process (Wattenbarger and McDougal, 1988).
- **Radio Frequency (RF)/Microwave Heating Technologies.** This extraction technique would use RF electromagnetic waves at high (microwave) frequencies to dissolve the oil from the formation without any external solvents. Unlike traditional thermal recovery methods, microwave heating causes friction by vibration of molecules, which results in dielectric heating of the reservoir. Heat and mass transfer in different environments under microwave influence has been studied internationally, but its application as an enhanced oil recovery (EOR) method is not yet fully understood (Mukhametshina and Martynova, 2013).
- **Microbial and Surfactant Stimulation.** This experimental extraction technology would use surfactant/detergent solvents and microbes to break the heavy crude chemical bonds at oil reservoir temperatures. The oil would dissolve into a new boundary layer between the existing water and the heavy tars for extraction and treatment/refining at the surface.

While each of these alternative heating technologies may work in theory, they are experimental, are not as efficient as the proposed steam injection, and/or have not been proven to be technically or economically feasible to replace steam injection for oil recovery at the Project site. Therefore, alternative heating technologies have been eliminated from full consideration in this EIR.



0 1 2
Scale in Miles

- Well
- Foxen Canyon Pipeline
- Area East Cat Canyon Property
- Oil and Gas Field

Figure 2-24

Alternative Oil and Gas Development Sites

- **Water Flooding**. Another alternative method of extracting the oil from the formations is the use of hot and cold water flooding. The Applicant has proposed the use of steam to extract the crude oil which requires a substantial amount of energy to purify and heat the water to produce steam. Hot water flooding or cold water flooding are less energy intensive methods that can be used. The use of hot water flooding requires that water be heated to lower temperatures than required to produce steam, thereby using less energy, and then injected into the formation to mobilize the crude oil. Cold water can also be used, which does not require any heating, and therefore uses minimal energy.

  Generally, the use of hot water instead of steam produces less crude oil recovery due to the lack of steam pressure and gas drive, in addition to the viscosity reduction and swelling as recovery mechanisms due to the higher temperatures. Depending on the crude oil characteristics and soil properties, and the amounts of material injected, steam can recover over 80 percent of the crude oil while hot water injection can recover approximately 20 percent. Cold water flooding could extract approximately 5 percent of the crude oil (Allawzi, 2008). Furthermore, due to the high API gravity of crude oil found in the Cat Canyon Oil Field oil production would require a minimum temperature for production that may not be achieved through hot water flooding. Hot water flooding would recover substantially less of the crude oil than the proposed Project would render the project not economically feasible, this alternative has been eliminated from further consideration.

2.11.2.3 Conventional Drilling Alternative

Public comments received during scoping suggested use of conventional drilling for the proposed oil wells. Conventional drilling of wells refers to oil that is produced from reservoirs using traditional drilling, pumping and compression techniques and that does not require additional well stimulation techniques, such as steam injection or hydraulic fracturing.

Under the Project, most wells would be vertical wells, but Aera proposes to employ some horizontal drilling where needed to maximize use of existing well pads, minimize ground disturbance and avoid resources. While steam injection is proposed, no hydraulic fracturing would occur at any of the proposed wells.

The East Cat Canyon Oil Field has been historically produced using conventional drilling and when the conventional wells were no longer economically viable, they were abandoned and all oil production ceased. Given the current availability of steam injection, production of remaining oil reserves from the previously produced field has economic merit. Use of conventional drilling would not be an economically viable alternative. Since the remaining oil reserves from the East Cat Canyon Oil Field cannot be produced utilizing solely conventional drilling techniques due to the viscose nature of the oil within the oil-bearing Brooks reservoir, this alternative has been eliminated from further consideration.

2.11.2.4 Renewable Energy Sources Alternative

Public comments received during scoping suggested alternative methods of energy production, such as solar or wind technologies.

The crude that would be extracted under the Project would be processed into oil and gas for cars, as well as other vehicles and equipment. On the other hand, solar and wind energy generation creates electricity that goes into the electrical grid, which is a different form of energy than is proposed under the Project. Further, the proposed Project site is not located within one of the four potential areas identified by the Santa Barbara Community Environmental Council (CEC, 2006) as a promising wind resource area, which include the Zaca Lake Region; Channel Islands of Santa Cruz, San Miguel, and Santa Rosa; offshore areas near Vandenberg Air Force Base; and Hollister Ranch Region. Therefore, a solar or wind generation alternative would not be a viable alternative to replace the proposed Project, nor would it meet the Project

Objectives stated in Section 2.3 (Project Objectives) or the purpose of the proposed Project to re-establish oil production at the East Cat Canyon Oil Field.

However, installation of solar facilities near the Project site could be used to power steam generation onsite. While renewable generation would reduce onsite emissions during operation of the steam generators, their installation would create additional adverse direct and indirect environmental impacts.

Installation of solar or wind facilities without battery storage would mean that steam could only be produced during sunny/windy days and during the daytime, reducing the efficiency of the steam injection process. Furthermore, it would also take over 1,200 acres of solar facilities to produce the equivalent amount of steam. For example, a 100-acre solar site could generate approximately 1,000 mmbtu/day, whereas the Project includes six once-through steam generators, rated at 85 mmbtu/hour each (approximately 12,240 mmbtu/day) (County of Santa Barbara, 2016).

Although utilizing renewable energy generation onsite would reduce onsite greenhouse gas (GHG) emissions, it would not necessarily introduce greater efficiencies than the mitigated Project, where GHG reductions would be required as part of the mitigation measures. Solar facility construction requires complete clearing and somewhat leveling of the affected area. Due to the potential impacts associated with the construction of a solar facility within an approximate 1,200 acre area (biological, cultural, hydrology/SWPPP, construction emissions, transportation of panels/materials, etc.), and the continued need for the combustion of the produced gas onsite (thereby not eliminating onsite GHG emissions), this alternative has been eliminated from further consideration.

2.11.2.5 Natural Gas Pipeline Alternatives

Three potential alternative natural gas pipeline alignments were considered that would shorten the length of Aera's proposed 14-mile natural gas pipeline and reduce potential biological impacts, and would avoid the town of Orcutt and reduce public risk. The alternative connection points are shown in Figure 2-25 (Natural Gas Pipeline Alternatives) and their alignments are described as follows:

- **Natural Gas Pipeline Option 1: Connect Near Garey**. Under Option 1, a new, approximately 6.5-mile natural gas pipeline would be constructed in existing roads to connect from the Central Processing Facility area to an existing SoCalGas distribution line in the community of Garey (see Figure 2-25, Natural Gas Pipeline Alternatives).

  The alternative pipeline alignment would follow the proposed route under Cat Canyon Road to Palmer Road. At Palmer Road the Option 2 alignment would diverge from the proposed route and would follow Palmer Road east then north for approximately 2 miles to Foxen Canyon Road. The alternative would turn northwest on Foxen Canyon Road for approximately 2.5 miles where it would connect into an existing SoCalGas natural gas distribution line just south of Santa Maria Mesa Road in Garey.

  Depending on the timing of construction, in order to reduce the duration of potential traffic and land use impacts, the installation of the natural gas pipeline in Foxen Canyon Road could potentially occur at the same time that the ERG Foxen Pipeline is installed (see Section 3, Cumulative Scenario).

  Alternative Conclusion: SoCalGas has stated that the high-pressure distribution/supply line at the alternative tie-in location would not provide adequate pressure for Aera's natural gas demands for the proposed Project. Therefore, this alternative natural gas pipeline route would not be technically feasible and it has been eliminated from consideration in the EIR.

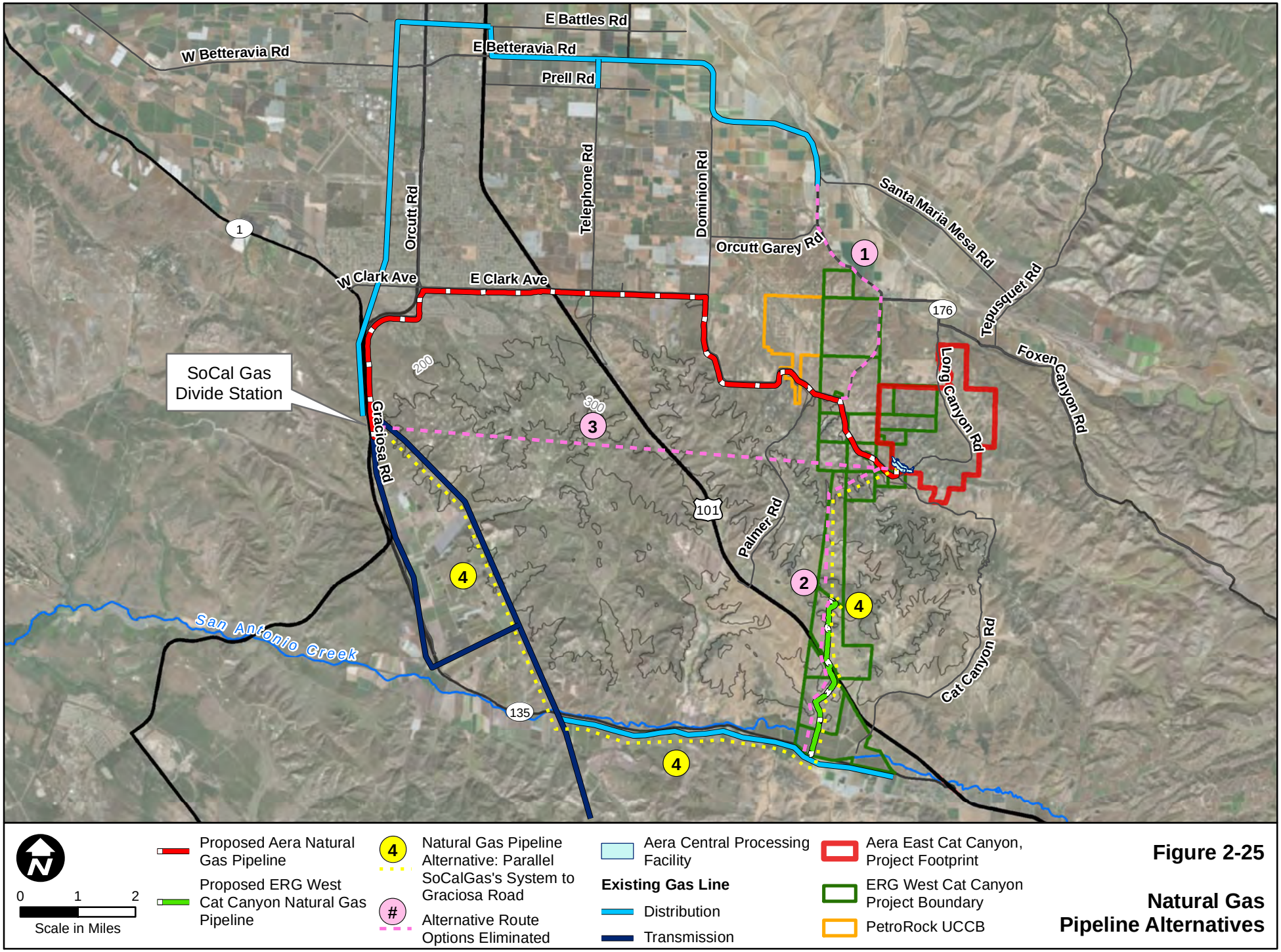


Figure 2-25

Natural Gas Pipeline Alternatives

- **Natural Gas Pipeline Option 2: Expand or Parallel ERG's System**. Under Option 2, the proposed natural gas pipeline would either parallel or connect into and utilize the natural gas pipeline proposed for the nearby ERG West Cat Canyon Revitalization Plan (see Section 3, Cumulative Scenario). The potential Natural Gas Pipeline Option 2 alignment is shown on Figure 2-25, and the length would be dependent upon whether the Aera pipeline could connect into ERG's natural gas pipeline within the ERG facility or if a parallel system is required.

  As part of the West Cat Canyon Revitalization Project, ERG is proposing to replace an existing 4-inch diameter natural gas pipeline with an 8-inch diameter pipeline at the southern end of its site (see Figure 2-25, Natural Gas Pipeline Alternatives). The new 8-inch diameter pipeline would essentially follow the same route as the existing 4-inch line, but would be located primarily within vineyard roadways, and traverses vineyards in some locations. Under Option 2, either the 8-inch line could be built with larger capacity (i.e., larger diameter pipe) to accommodate the Aera natural gas delivery, or a parallel system could be built.

  Alternative Conclusion: Similar to Option 1, SoCalGas has stated that the high pressure distribution/ supply line at ERG's alternative tie-in location would not provide adequate pressure for Aera's natural gas demands for the proposed Project. Likewise, Aera would not be able to tie into ERG's system directly due to capacity limitation. Therefore, the Option 2 alternative natural gas pipeline route would not be technically feasible and it has been eliminated from consideration in the EIR.

- **Natural Gas Pipeline Option 3: Cross-County to Graciosa Road**. Under Option 3, the natural gas pipeline would generally travel cross-country to the west for approximately 9 miles, crossing under Highway 101 via HDD to tie into the SoCalGas system at the Divide Station on Graciosa Road, the same connection location as the proposed Project.

  Alternative Conclusion: While this tie-in location is technically feasible, the steep topography and a much greater level of disturbance across undisturbed lands would create greater environmental impacts, namely to biological resources, and geologic and hydrological resources from soil erosion. Disturbance within undisturbed lands could result in the removal of native vegetation, disturbance of drainages and associated resources, as well as increase the chance of noxious weed introduction. Potential sensitive species that may be encountered along the alternative alignment include: American badger, black-flowered figwort, California red-legged frog, Hoover's bent grass, Kellogg's horkelia, La Purisima manzanita, Lompoc yerba santa, sand mesa manzanita, and western spadefoot. Finally, increased disturbance has the potential to disturb unknown cultural resources. Therefore, due to greater potential environmental impacts, Option 3 has been eliminated from full consideration in the EIR.

Note that a natural gas pipeline alternative that would parallel ERG and SoCalGas's system to the Divide Substation on Graciosa Road (Option 4) has been retained for full consideration in the EIR (see Section 2.11.4.5, Natural Gas Pipeline Reroute Alternative).

2.11.3 No Project Alternative

CEQA requires that the alternative of the "No Project" be evaluated along with its impacts as part of the EIR (CEQA Guidelines Section 15126.6(e)(1)). For projects that are other than a land use or regulatory plan, the No Project Alternative is the circumstances under which a project does not proceed. If disapproval of the project under consideration would result in predictable actions by others, such as the proposal for another project, this No Project consequence should be discussed (CEQA Guidelines Section 15126.6(e)(3)(B)). The CEQA Guidelines go on to say that the Lead Agency should analyze the impacts of the No Project Alternative by projecting what would reasonably be expected to occur in the foreseeable future if a proposed Project was not approved (Guidelines Section 15126.6(e)(3)(C)).

The proposed Project includes the re-establishment of oil production in an existing oil field using a thermal enhanced oil recovery process with the construction and restoration of approximately 72 well pads, construction and restoration of over 9 miles of field access roads, and drilling of up to 296 wells. The proposed Project also includes construction of new processing facilities, field systems, utility connections, and the transport of produced oil by truck. Under the No Project Alternative, the proposed Project would not occur and the field would continue to be abandoned.

2.11.4 Alternatives Carried Forward

In addition to the No Project Alternative, six alternatives have been carried forward for detailed analysis in the EIR, in addition to the 'No Project Alternative' as required per CEQA. Based on the environmental analysis of the proposed Project in Sections 4.2 thru 4.10, potentially significant impacts were determined to occur in the following resources areas: Biological, Cultural, and Water Resources; Geology and Geologic Hazards; Air Quality and GHG; Hazardous Materials/Risk of Upset/Fire; Noise; and Traffic and Transportation. The following alternatives were found to be technically and economically feasible, meet the basic objectives of the proposed Project, and would further reduce potential significant impacts. The alternatives carried forward include:

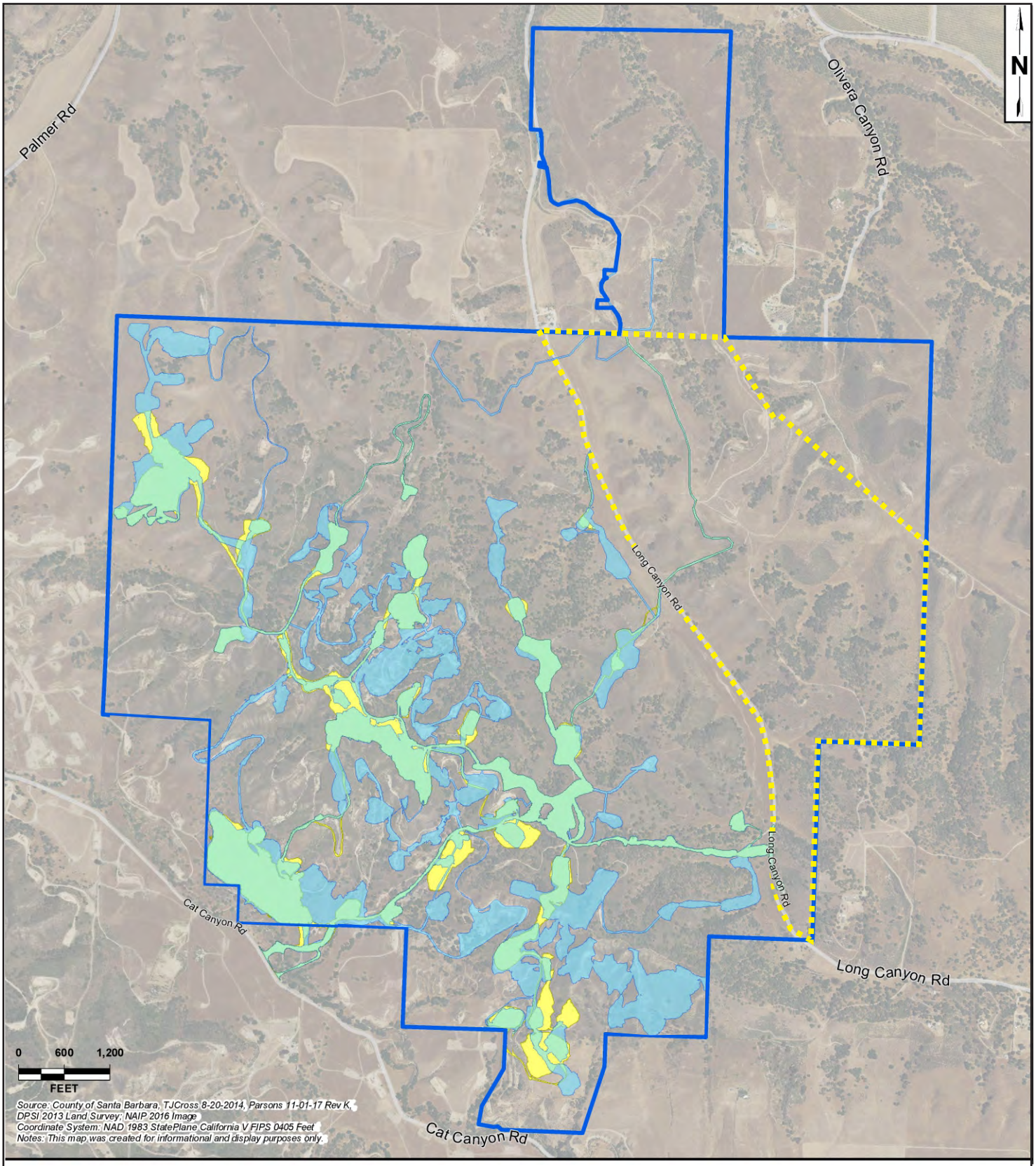
- Alternative 1: Reduced Footprint Alternative
- Alternative 2: Oak Avoidance Alternative
- Alternative 3: Phillips 66 Pipeline Alternative
- Alternative 4: Plains Pipeline Alternative
- Alternative 5: Natural Gas Pipeline Route Alternative

Section 5, Comparison of Alternatives, assesses the impacts of each of these alternatives and provides a summary of impacts of the proposed Project and each alternative that has been carried forward for evaluation.

2.11.4.1 Alternative 1: Reduced Footprint Alternative

This alternative was developed by Aera at the request of Santa Barbara County to reduce ground disturbance and other associated impacts of the Project. Under the Reduced Footprint Alternative, Aera would utilize more horizontal drilling (i.e., angled drills instead of vertical) to reach reservoir areas, which would allow more wells to be drilled per well pad, thereby reducing the overall number of well pads and associated ground disturbance of the Project. Additional test bores would be required by Aera to confirm the upper and lower reservoir depths to ensure the feasibility and proper positioning for horizontal drilling. The results will serve to inform the footprint of the Reduced Footprint Alternative. In addition, the increased drilling angle required to reduce the disturbance footprint is more complicated and costly to drill, operate, and maintain, and therefore more well replacements may be required under the alternative than for the proposed Project.

The Reduced Footprint Alternative is illustrated in comparison to the proposed Project in Figure 2-26 (Reduced Footprint Alternative and Proposed Project Comparison). The estimated disturbance for each component of the Reduced Footprint Alternative is compared to the proposed Project in Table 2-8. A comparison to the Oak Avoidance Alternative, which is discussed in Section 2.11.4.2 (Alternative 2: Oak Avoidance Alternative), is also included in Table 2-8.



Source: Aera, 2017.

- Aera Energy LLC Property
- Proposed Project Footprint (8/20/2014)
- Reduced Footprint Alternative (01/11/2017)
- Reduced Footprint Alternative Conservation Easement
- Overlap disturbance between the Proposed Project and the Reduced Footprint Alternative

Figure 2-26

Reduced Footprint Alternative and Proposed Project Comparison

Table 2-8. Reduced Footprint Alternative, Oak Avoidance Alternative, and Proposed Project Disturbance Comparisons

Component	Proposed Project	Reduced Footprint Project Alternative	Oak Avoidance Alternative [see Section 2.11.4.2]
Total Disturbed Acreage (temporary and permanent)	304.7 acres of 2,112-acre Project site	163.65 acres	136.1 acres
Disturbed Acreage (temporary)	103.3 acres	48.5 acres	36.8 acres
Disturbed Acreage (permanent)	201.4 acres	115.19 acres	95.5 acres
Active Wells	296	No Change	No Change
Replacement Wells	30	Possible Change*	Possible Change*
Well Pads	72	26	37
Number of Steam Generators	6	No change	No change
Access Roads	9 miles	9 miles	10 miles (includes 0.5 mile of pipeline/corridor roadway)
Cut and Fill Volume (Total)	6.6 MM cubic yards	3.1 MM cubic yards	2.3 million cubic yards
Cut Volume	3.4 MM cubic yards	1.6 MM cubic yards	1.2 million cubic yards
Fill Volume	3.2 MM cubic yards	1.4 MM cubic yards	1.1 million cubic yards
Total Net	155K cubic yards	200K cubic yards	1,000 cubic yards
Conservation Easement Acreage	686.4 acres	TBD, between 404 and 686.4 acres	TBD, between 222 and 686.4 acres
Oak tree impacts (mature tree removals)	1,500 trees	735 trees	281 trees
Oak Tree Replacements -Conservation Easement Acreage Required	237 net acres [~687 gross acres]	116 net acres [~222 gross acres]	40 net acres [~222 gross acres]
Project California tiger salamander (CTS) Reproductive Value (USFW Searcy Units)	31,443	14,167	11,865
Conservation Area Reproductive Value (USFW Searcy Units; using gross acreage needed to replace oak habitat)	42,741	42,293	40,528
Mitigation Ratio	1.36:1	2.99:1	3.42:1
Vegetation Impacts (temporary and permanent)	240.45 acres	117.58 acres	86.23 acres
Vegetation Impacts (temporary)	104.61 acres	41.40 acres	30.93 acres
Vegetation Impacts (permanent)	135.84 acres	76.18 acres	55.30 acres
Peak Production Barrels/day – oil	10,000	No change	No change
Natural Gas Pipeline	14 miles, 8-inch pipeline	No change	No change
Electrical Power Line	0.3 miles, 115 kV	No change	No change
Vehicle Trips Per Day (includes employees, contractors, incoming and outgoing deliveries including oil shipping)	532 (199 tanker truck, 18 non-tanker truck, 315 employee)	No change	No change

Source. Aera, 2017.
*Given the increased drilling angle required to reduce the disturbance footprint is more complicated and costly to drill, operate, and maintain, and therefore more well replacements may be required under the alternative than for the proposed Project.

2.11.4.2 Alternative 2: Oak Avoidance Alternative

This alternative was developed by Aera at the request of Santa Barbara County to reduce Project impacts to oaks to the greatest extend practical, beyond what was proposed under the Reduced Footprint Alternative (see Section 2.11.4.1). Under the Oak Avoidance Alternative, Aera would utilize more horizontal drilling (i.e., angled drills instead of vertical) to reach reservoir areas, which would allow more wells to be drilled per well pad, thereby reducing the overall number of well pads and associated oak tree and woodland habitat removal. Additional test bores would be required by Aera to confirm the upper and lower reservoir depths to ensure the feasibility and proper positioning for horizontal drilling. The results will serve to inform the footprint of the Oak Avoidance Alternative.

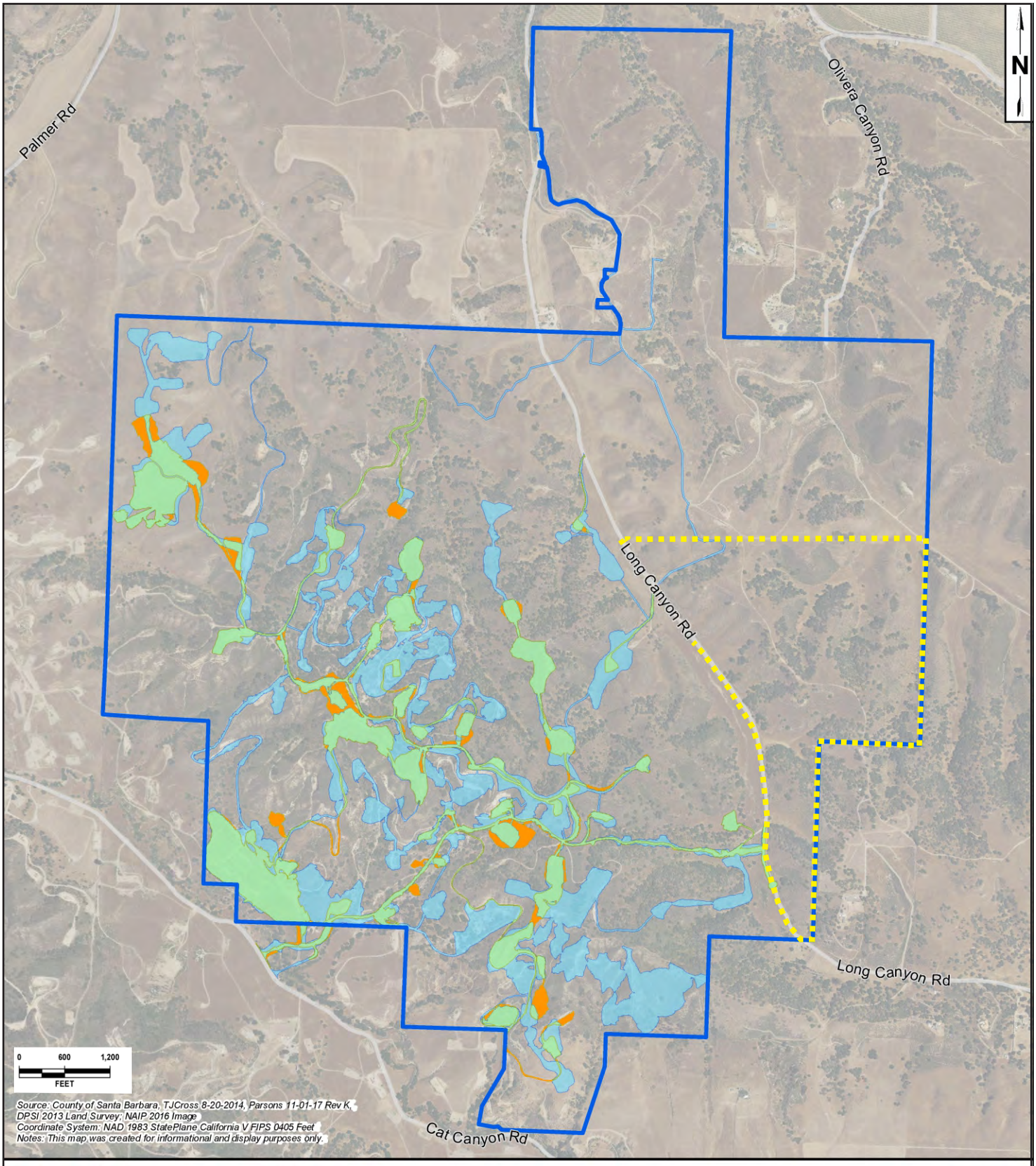
In addition to utilizing more horizontal drilling, Aera has designed the Oak Avoidance Alternative to minimize road widths and well pad areas, reroute roads, relocate well pads, refine grading plans, and fine tune proposed development areas with a tree-by-tree analysis to reduce impacts to oak trees by 81 percent as compared to the Proposed Project.

The Oak Avoidance Alternative is illustrated in comparison to the proposed Project in Figure 2-27 (Oak Avoidance Alternative and Proposed Project Comparison). The estimated disturbance for each component of the Oak Avoidance Alternative is compared to the proposed Project as well as the Reduced Footprint Alternative in Table 2-8 in Section 2.11.4.1 (Alternative 1: Reduced Footprint Alternative). Overall the Oak Avoidance Alternative would result in a 55 percent reduction in total disturbed acreage and a 36 percent reduction in cut and fill volumes. However, the increased drilling angle required to reduce the disturbance footprint is more complicated and costly to drill, operate, and maintain, and therefore more well replacements may be required under the alternative than for the proposed Project.

2.11.4.3 Alternative 3: Phillips 66 Pipeline Alternative

The Phillips 66 Pipeline Alternative was developed to utilize the local Phillips 66 pipeline facilities to transport Project produced crude oil to a Bay Area refinery; thereby, eliminating the need for and impacts associated with tanker truck transport of blended produced oil to Aera's Belridge facility. To accomplish this alternative, one of two scenarios would need to occur:

- **Scenario 1**: Under this Alternative, Aera would construct an approximately 4.5-mile pipeline from their Central Processing Facilities to ERG's Cantin Tank Battery. The proposed pipeline would then connect to the approved 2.9 mile ERG Foxen Petroleum Pipeline (FPP), which was evaluated under an adopted CEQA document (Case No. 13EIR-00000-00002 and State Clearinghouse No. 2013061011) and approved by the County Planning Commission on March 11, 2015. Once transported to the ERG Cantin Tank Battery, the crude oil would be piped to the Phillips 66 Sisquoc Pipeline (see Figure 2-28). On February 6, 2018, the Board of Supervisors adopted an ordinance granting a franchise agreement with ERG for construction of the FPP within public road rights-of-way. No specific schedule for FPP construction has been provided however, ERG accepted the terms and conditions of the franchise agreement by letter dated March 5, 2018. Since work on the pipeline is to commence within four months from the effective date of the franchise, ERG has begun the acquisition of pipeline casing and submitted the first Zoning clearance package in September 2018.
- Scenario 2: In the instance that ERG does not construct the FPP, Aera would build a new approximate 7 to 8 mile pipeline to connect their East Cat Canyon facility to the Phillips 66 Sisquoc Pipeline in place of the FPP. For purposes of this Alternative, the pipeline alignment is assumed to be similar to the approved FPP alignment.

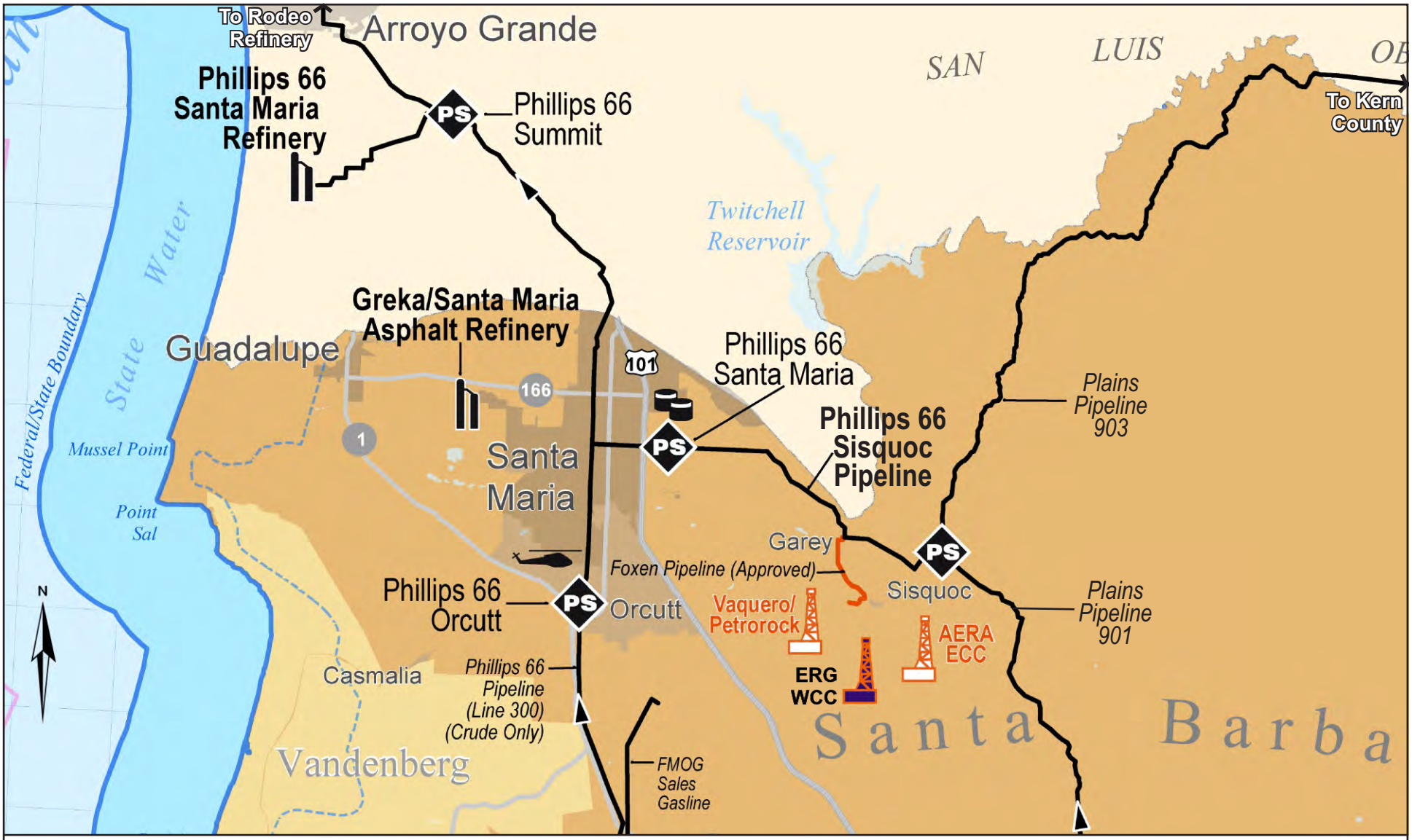


Source: Aera, 2017.

- Aera Energy LLC Property
- Permit Case Project Footprint eliminated disturbance
- Oak Avoidance Alternative new disturbance
- Oak Avoidance Alternative Conservation Easement
- Overlap disturbance between the Permit Case and Oak Avoidance Footprints

Figure 2-27

Oak Avoidance Alternative and Proposed Project Comparison



Source: Santa Barbara County Planning and Development, 2017.

0 1 2 3 4 5 10 15 Miles

Figure 2-28

Regional Pipeline Network

The Phillips 66 Sisquoc Pipeline connects to Santa Maria Pump Station which would send the crude to the Phillips 66 Santa Maria Refinery in San Luis Obispo County via the Line 300 system (see Figure 2-28, Regional Pipeline Network). The gas-oil product would then be pipelined to Phillip 66's Rodeo, CA refinery for further refining.

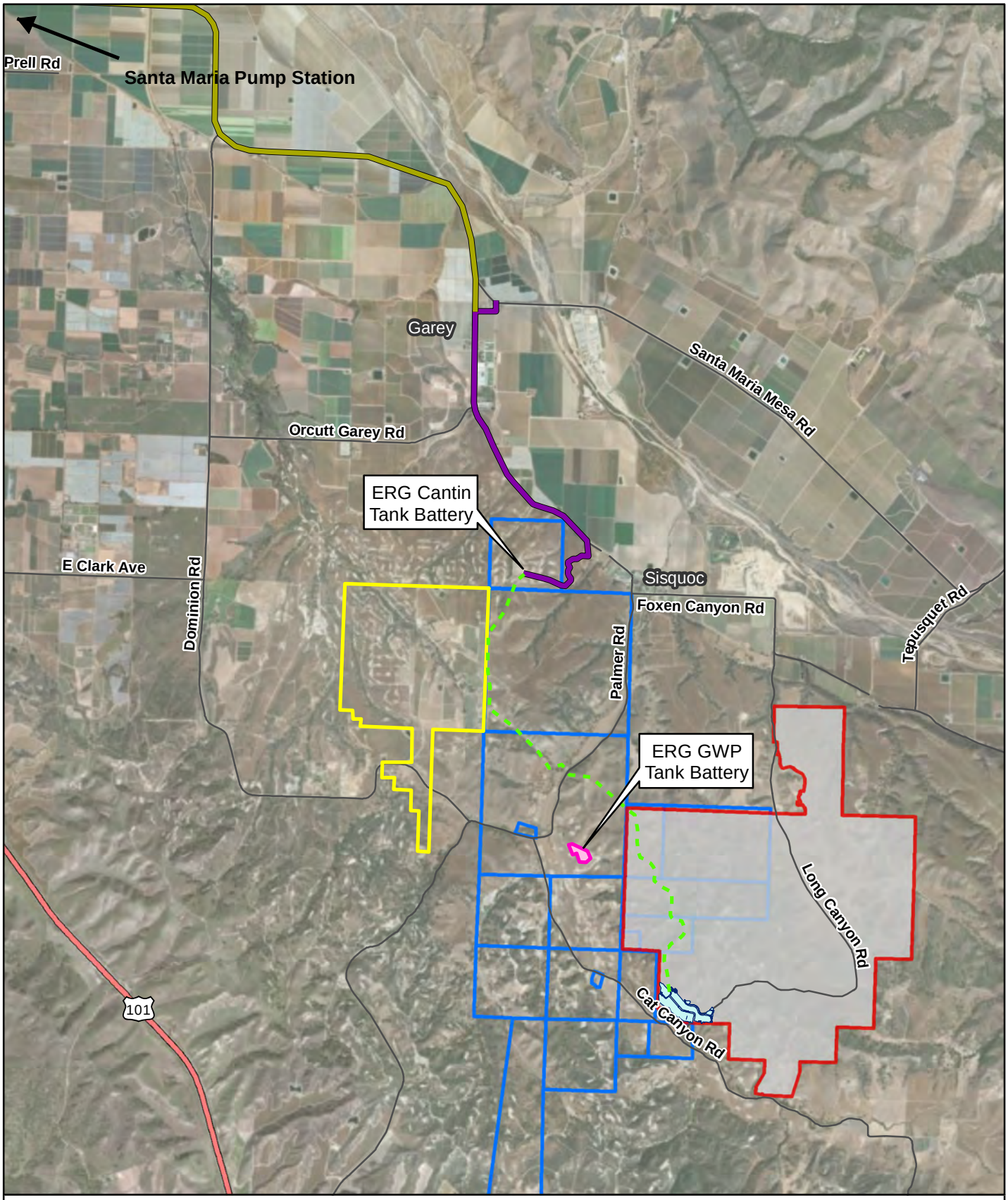
Historically, Plains All American Pipeline, L.P., (Plains) Line 901 was used to transport south County off-shore crude production to the Plains Sisquoc Pump Station where the crude could either travel west into the Phillips 66 system or northeast in Plains Pipeline 903 to the San Joaquin Valley (see Figure 2-28). However, Plains Lines 901 and 903 were shut down on May 19, 2015 in response to a pipeline rupture which resulted in the release of crude oil. With the shutdown of the Plains' Pipeline system, no offshore crude is being transported north in Line 901, so excess capacity is currently available within Phillip 66's Santa Maria Refinery and associated Line 300 system. However, on September 22, 2017, ExxonMobil submitted an application requesting the interim trucking of limited crude oil production of the Santa Ynez Unit (approximately 11,000 bpd) from ExxonMobil's facility located in Las Flores Canyon (LFC) to either the Phillips 66 Santa Maria Pump Station or to the Plains' Pentland Station in Kern County (County of Santa Barbara, 2018). This application is under County review.

If ExxonMobil transports their LFC crude production to the Phillips 66 Santa Maria Pump Station or Plains Line 901 were to be restarted or replaced in the future, thereby reinstating the transport of south County offshore crude production into the Phillips 66 system, the Santa Maria Refinery may not be able to process produced crude from the Project in the future; however, if Plains Line 901 is available, crude could be transported east. For purposes of the Phillips 66 Pipeline Alternative, it is assumed that capacity in the Phillips 66 pipeline system and Santa Maria Refinery will continue to be available throughout the expected Project life.

The FPP was permitted to include the construction and operation of two 8-inch crude oil pipelines, each with a 25,000-barrel per day capacity; however, as proposed, only one pipeline would be operated at a time. Therefore, if all cumulative oil production projects in the surrounding area reach their productive capacities, the FPP system may not have sufficient capacity to handle the proposed Aera Project blended production, in addition to other proposed oil field development projects in the area (i.e., ERG's West Cat Canyon Oil Field Revitalization Plan and PetroRock's UCCB Project). Likewise, the Cantin Tank Battery is located within a previously disturbed area currently used to support ERG's existing oil and gas production, and tanker truck activities. Additional equipment installation required for Aera pipeline connection, pumping, pigging, metering, and monitoring would occur within the disturbed area.

Under the Phillips 66 Pipeline Alternative, to connect to ERG's FPP, Aera would construct an approximate 4.5-mile pipeline from their Central Processing Facilities to ERG's Cantin Tank Battery (located on ERG's Cantin Lease, APN 129-180-015). The pipeline route would travel from the Central Processing Facility to the northwestern corner of the Aera site and then traverse ERG leases to the Cantin Tank Battery (see Figure 2-29). As currently conceived, the connecting Aera pipeline would cross Cat Canyon Creek and up to three additional locations that are considered waters of the U.S. and/or waters of the State.

For purposes of this Alternative, it is assumed that trucking of light and blended crude oil would occur during Phase I and when the FPP and/or connection pipeline were non-operational due to unanticipated circumstances during Phase II. For Phase I (approximately 3 to 4 years), an estimated 1,366 barrels per day of light crude oil would be needed (9 tanker truck loads/day) for an estimated production of approximately 4,300 barrels per day of produced crude; thereby, requiring 74 one-way truck trips/day (9 LCO, 28 empty, and 37 blended). All truck trips would be to/from the Aera Belridge facility (140.4 miles). Construction of the connection pipeline would be completed prior to the commencement of Phase II operations.



Proposed Alternative Route
ERG FPP
Phillips 66 Sisquoc Pipeline
Aera East Cat Canyon Proposed Project Footprint
GWP Tank Battery
Aera Central Processing Facility
ERG West Cat Canyon Project Boundary
PetroRock UCCB

0 0.5 1
Scale in Miles

Figure 2-29

Phillips 66 Pipeline Alternative, FPP Alignment and Access

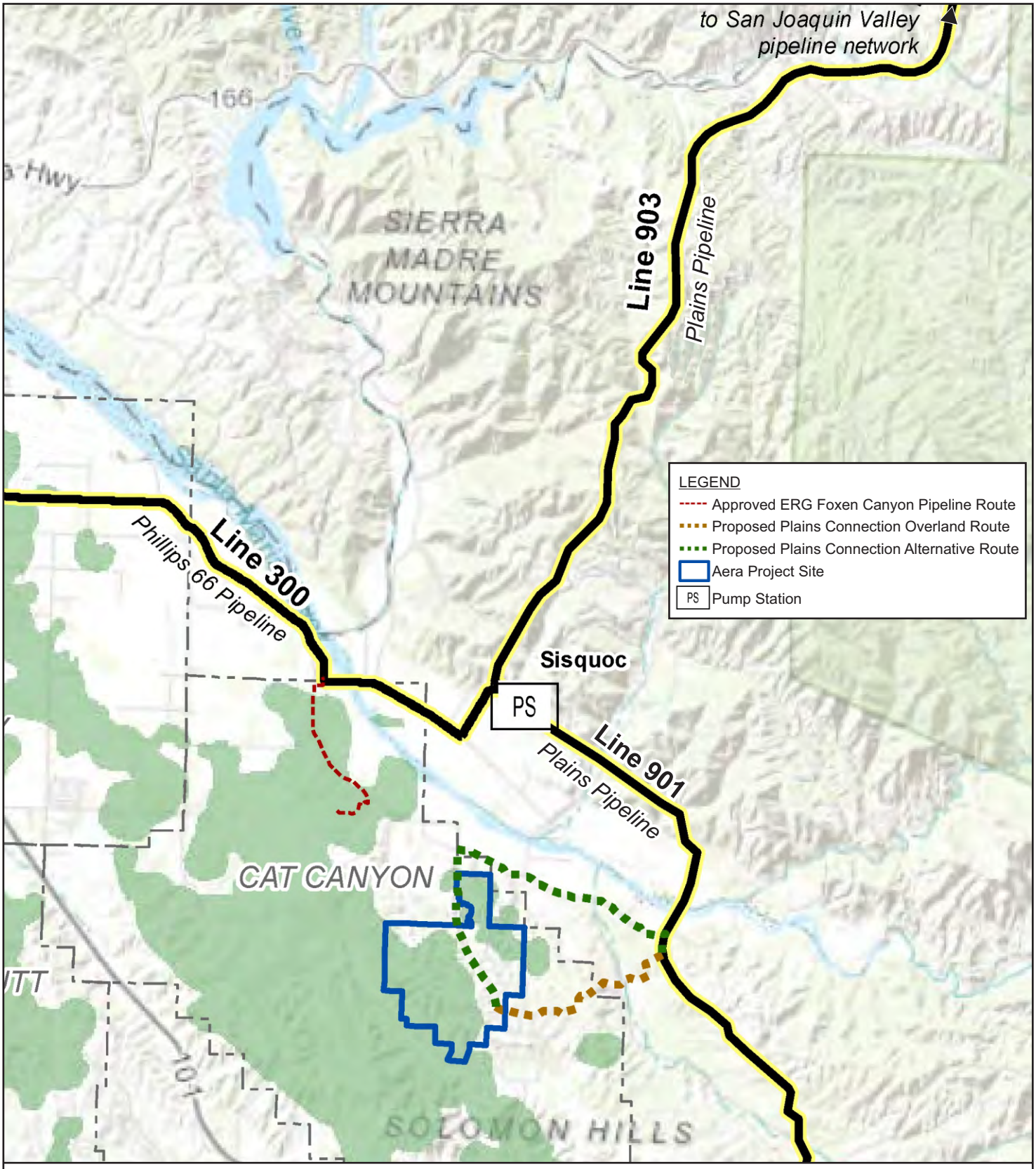
2.11.4.4 Alternative 4: Plains Pipeline Alternative

As noted under the Phillips 66 Pipeline Alternative (see Section 2.11.4.3), Plains Lines 901 and 903 were shut down on May 19, 2015 in response to a pipeline rupture which resulted in the release of crude oil. On August 15, 2017, Plains submitted three discretionary applications to the County for the replacement of the lines. The Plains Pipeline Alternative assumes that Plains Lines 901 and 903 will be permitted and replaced in the future. However, given Aera's proposed phasing of well development, minimal trucking of blended produced crude could be required over the short term under the Plains Pipeline Alternative while the Plains Lines are constructed.

The Plains Line 901 and 903 pipeline system (former constructed and operated as Celeron) was evaluated under the California Environmental Quality Act (State Clearing House No. 19831109020) and approved on February 18, 1986 by the Board of Supervisors on recommendation from the Planning Commission. Although the Plains pipeline system is currently non-operation, once the Pipeline and Hazardous Materials Safety Administration's Corrective Action Orders are addressed Plains maintains the ability to restart the system without decision maker approval. All maintenance activities would be covered under the existing CEQA document. However, on August 15, 2017, Plains submitted a discretionary application (Case Nos. 17DVP-00000-00010, 17CUP-00000-00027 and 17CDP-00000-00060) to Santa Barbara County Planning and Development Energy, Minerals and Compliance Division for the complete replacement of their existing Line 901 and 903 system. The Plains Replacement Pipeline Project is subject to CEQA and the Energy, Minerals and Compliance Division will be preparing a CEQA document to analysis and disclose all impacts related to the replacement of the Line 901 and 903 system. Information regarding the status of the Plains application can be found online at the Energy, Minerals and Compliance Division website.

The Plains Pipeline Alternative was developed to utilize regional pipeline facilities to transport Project produced crude oil to Los Angeles Basin and Bay Area refineries; thereby, eliminating the need for and impacts associated with tanker truck transport of blended produced oil to Aera's Belridge facility. To accomplish this alternative, the Plains Pipeline system to Kern County would be utilized (see Figure 2-28). Within Kern County, pump stations at Pentland and Emidio are available to route crude oil in existing pipelines to the Bay Area and Los Angeles, respectively. To access the Plains Pipeline system, Aera blended crude would need to connect to Plains Line 901 to the east (see Figure 2-30, Plains Pipeline Alternative). From there, crude would continue in a general northly direction to the Sisquoc Pump Station and then travel in a northeasterly direction in Plains Line 903 to the pump stations in Kern County for transport either north or south.

As illustrated on Figure 2-30, two possible connection routes are available to connect the Aera East Cat Canyon Oil Field to Plains Line 901: (1) An overland route of approximately 3 miles, and (2) a route of slightly over 6 miles that would lie predominately under existing asphalt paved roads. Both routes would connect to the east side of the Project site near Long Canyon Road. In addition, both would require the Project to add about 1.5 miles of in-field pipeline, as well as additional facilities for transfer, pumping and measurement. For purposes of the Plains Pipeline Alternative, the longer connection route is assumed since it would minimize any new clearing and resultant potential biological, hydrological, and cultural resource impacts (in comparison to the overland route), since the connection would be placed primarily with the roadbed or shoulders of existing paved roadways.



Source: Aera, 2017.

0 2 4
MILES

N

Figure 2-30

Plains Pipeline Alternative

As described in the Project Description, due to the low API gravity of oil produced from the East Cat Canyon Oil Field, light crude oil (LCO) would be trucked in from Aera's Belridge Facility in Kern County to be used as a diluent (140.4 miles one-way). To meet Plains' viscosity specifications, approximately 75 one-way tanker truck trips/day of light crude oil would be needed. Further, the Plains Basic Sediment and Water specification (1%) is below the estimated Aera specification of 3 percent. To achieve this specification, additional processing facilities would need to be incorporated into the proposed Aera Central Processing Facility to remove solids from the produced crude. Under the proposed Project, these facilities are not required as solids removal would occur at Aera's Belridge Facility. This alternative would increase daily trips associated with light crude oil from 21 to 75, but would reduce total proposed Project truck one-way trips (light and blended crude, and empty trucks) from 190 to 150. Under this Alternative, light crude trucks would return to the Aera Belridge Facility empty.

For purposes of this Alternative, it is assumed that trucking of light and blended crude oil would occur during Phase I and when the Plains Pipeline and/or connection pipeline were non-operational due to unanticipated circumstances during Phase II. For Phase I (approximately 3 to 4 years), an estimated 1,366 barrels per day of light crude oil would be needed (9 tanker truck loads/day) for an estimated production of approximately 4,300 barrels per day of produced crude; thereby, requiring 74 one-way truck trips/day (9 LCO, 28 empty, and 37 blended). All truck trips would be to/from the Aera Belridge facility (140.4 miles). Construction of the connection pipeline would be completed prior to the commencement of Phase II operations.

2.11.4.5 Alternative 5: Natural Gas Pipeline Reroute Alternative

An alternative natural gas pipeline alignment (Option 4) was developed that would avoid the town of Orcutt and associated population centers (see Figure 2-25, Natural Gas Pipeline Alternatives, which is included after Section 2.11.25).

As shown on Figure 2-25, under the Natural Gas Pipeline Alternative Option 4, the proposed 8-inch natural gas pipeline would travel southwest from the Aera Central Processing Facility, then south to parallel ERG's existing system, as well as ERG's natural gas pipeline proposed for the nearby ERG West Cat Canyon Revitalization Plan for approximately 6.5 miles south to Highway 135 (see Section 3, Cumulative Scenario). From there, the alternative would continue beyond the endpoint of ERG's proposed pipeline by turning west to parallel Highway 135 and an existing SoCalGas distribution pipeline for approximately 4.7 miles. The alternative alignment would turn north-northwest to parallel an existing SoCalGas transmission pipeline for 6.2 miles to interconnect at the Divide Station on Graciosa Road as shown as Option 4 on Figure 2-25 (Natural Gas Pipeline Alternatives) where SoCalGas has available natural gas capacity. The overall length of Natural Gas Pipeline Alternative Option 4 would be approximately 17.4 miles, 3.4 miles longer than the proposed route. ERG's natural gas pipeline would not be able to deliver natural gas fuel at a sufficient rate to meet the needs of Aera's thermal enhanced oil recovery steam generators.

Land uses along the alternative route include existing oil and gas development, open space, and agriculture and vineyards. In addition, the alternative would cross several creeks and canals, including San Antonio Creek and its tributaries approximately four times along Highway 135. Potential sensitive species that may be encountered along the alternative alignment include: American badger, California red-legged frog, California tiger salamander, Hoover's bent grass, La Purisima manzanita, sand mesa manzanita, unarmored threespine stickleback, and western spadefoot.

Although Natural Gas Alternative Option 4 could have greater potential biological impacts and would be longer than the proposed route, this alternative would traverse less densely populated lands than the proposed alignment and avoid sensitive land uses such as schools and churches. By routing the natural gas pipeline farther from population centers and sensitive land uses, the consequences to the public in the event of upset or a pipeline leak would be reduced.