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6.1 INTRODUCTION

Title 20 California Code of Regulations requires an applicant to discuss "the range of reasonable alternatives to the project, including the no project alternative…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 an evaluation of the comparative merits of the alternatives."

California is the most populous state in the U.S. Its population is projected to continue to grow at a rate of just over 1 percent per year until 2030, putting California above the national population growth rate of about 0.8 percent per year. The combination of continued population growth and economic prosperity will result in robust growth in energy demand. The California Energy Commission (CEC) estimates that to meet peak energy demand growth, the state will need to add over 9,000 megawatts (MW) in capacity between 2008 and 2018.

This Project represents an opportunity to satisfy several of California's environmental policy objectives regarding low-carbon power generation and greenhouse gas reduction while encouraging sustainable economic growth. The Project will respond to the future energy demands of California, and will play an important role in eventually meeting the state's objective of reducing carbon dioxide (CO_2) emissions to 1990 levels by 2020.

The Applicant used the following general evaluation criteria as a means of evaluating and ranking alternatives:

- **Climate Change –** the selected alternative must **s**upport the need for baseload electricity generated by technologies that reduce green house gas emissions.
- **Economic feasibility** – the selected alternative must be economically feasible (based on the economic value and costs of the Project compared to the benefits of the Project and the drawbacks of the alternatives).
- **Support energy security** – the selected alternative must support the United States' and California's goal of energy independence through the use of domestic energy products and development of hydrogen infrastructure.
- **Allow for carbon capture and sequestration** – the selected alternative must not impede the ability of creating low-carbon energy and must allow for carbon capture and sequestration.

Additional specific evaluation criteria are provided in the sections below relative to alternative Project Site and linear facilities, generating technologies, and water supplies.

6.2 NO PROJECT ALTERNATIVE

The No Project Alternative fails to achieve the climate change, environmental, economic, and energy security benefits at one of the top candidate sites for carbon capture and sequestration in California. Furthermore, California's stated goal of being a world leader as exemplified by the laws and policies discussed below will not be advanced with the No Project Alternative.

The Project design described in Section 2.0, Project Description, represents a project that offers significant environmental and energy security benefits over the No Project Alternative by initiating 90 percent capture and sequestration of carbon (as carbon dioxide) from the syngas (more than 2 million tons per year), providing baseload low-carbon power while complying with

Best Available Control Technology (BACT) standards, boosting the California economy by approximately 1,500 construction jobs and 100 permanent operational positions, preserving fresh water sources by using brackish groundwater for the power plant, developing a broader slate of low-carbon fuel supplies thereby reducing the stress on natural gas supplies, and providing emission offsets.

The Project capital and operating costs as well as the associated environmental benefits were balanced such that the Project could provide baseload low-carbon power and some new technology development. In 2005, the state energy agencies issued Energy Action Plan II (EAP II). EAP II emphasized "[the] need to develop and tap advanced technologies to achieve [the] goals of reliability, affordability and an environmentally-sound energy future."

California has enacted a law, Assembly Bill 32 (AB 32), to reduce greenhouse gas emissions to 1990 levels by 2020. Furthermore, California Governor Schwarzenegger's Executive Order S-3-05 sets a state target of reducing greenhouse gas emissions to 80 percent below 1990 levels by 2050. AB 32 requires the California Air Resources Board (CARB) to assign emissions targets to each sector in the California economy and to develop regulatory and market methods to ensure compliance, which take effect in 2012. The California Public Utilities Commission (CPUC) and CEC are to develop specific proposals to CARB for implementing AB 32 in the electricity sector, possibly including a cap-and-trade program.

To reduce the state's reliance on conventional coal-fired power generation, the CEC has supported initiatives providing technical support for clean coal projects that can successfully compete for federal funding and incentives. California's specific interest is in high-efficiency commercial-scale facilities with western system applicability.[1]

The satisfaction of AB 32 and the Governor's Executive Order will probably require that the majority of new power generation brought on-line in the next decade must be zero- or low-carbon. In the absence of new low-carbon technologies or more aggressive policies, the state will miss its greenhouse gases reduction targets by a large margin. The Project's reliable, low-carbon generation will help California meet its greenhouse gases targets.

Senate Bill 1368 (SB 1368), passed in 2006, establishes an Emission Performance Standard (EPS) for greenhouse gas emissions from power plants used to serve baseload power in California. One of the requirements of SB 1368 is that utilities may only sign long-term contracts (5 years or more) with power plants that produce no more greenhouse gas emissions than a natural gas combined cycle (NGCC) power plant. Pursuant to SB 1368, CPUC has set the EPS at 1,100 pounds of carbon dioxide per megawatt hour (MWH) of electricity generated by the power plant. This law effectively prohibits California utilities from owning or contracting long term with coal-fired power plants, in- or out-of-state, unless they are operated with carbon capture and sequestration (CCS). The intended effect of SB 1368 is to encourage baseload low-carbon power production. The Project's greenhouse gas emissions will be well below this threshold requirement.

AB 1925, a law passed in 2006, requires the CEC to provide a report to the California legislature by November 2007 "with recommendations for how the state can develop parameters to accelerate the adoption of cost-effective geologic carbon sequestration strategies." This type of legislation clearly demonstrates California's commitment to supporting and encouraging in-state

[1] 22 September 2005 letter from CEC Chairman Desmond to John Geesman.

CCS demonstration technology. Again, the No Project Alternative will hinder the execution of both legislative mandates.

Consistent with EAP II, the economic performance will change over the life of the Project as technology advances occur and increasingly stringent climate change mitigation regulations are adopted.

Petroleum coke is often exported, primarily to Asia. The primary use is combustion in power plants, resulting in uncontrolled emissions of greenhouse gases and other criteria pollutants. This Project will gasify petroleum coke and capture and sequester the greenhouse gases.

The Project will add 250 MW of baseload low-carbon power to the grid, provide environmental benefits in regards to greenhouse gases (among others), and help California meet its obligations under AB 32, AB 1925, and SB 1368. In contrast, the No Project Alternative fails to meet these goals and fails to meet the basic Project Objectives described in Section 2.0, Project Description. As a result, the No Project Alternative was rejected in favor of the proposed Project.

6.3 SITE AND LINEAR FACILITIES LOCATION ALTERNATIVES

The Applicant used the following site evaluation criteria as a means of evaluating and ranking potential site alternatives, in addition to the general evaluation criteria described in Section 6.1:

- Proximity to carbon dioxide customer for enhanced oil recovery and sequestration
- Environmental impacts
- Safety (proximity to residents, schools, day care centers, etc.)
- Proximity to sensitive receptors (population and sensitive species)
- Environmental justice considerations
- Economic feasibility
- Site acreage (300+ acres), topography, lowest elevation (to maximize power generation)
- Minimize impacts on transportation corridors
- Feasibility of land acquisition
- Proximity to infrastructure to minimize impacts from site access and linear facilities
- Proximity to raw water supply

The Project Site was selected based on the proximity to a reservoir for enhanced oil recovery and sequestration, the available land (315 acres), the existing natural gas transportation, electric transmission, and brackish groundwater supply infrastructure that could support the proposed 250 MW of baseload low-carbon power generation. The routing of the linear facilities was thoroughly reviewed to limit the environmental impacts associated with the Project.

An electrical transmission line will interconnect the Project to Pacific Gas and Electric’s (PG&E) Midway Substation. As discussed in Section 4, Electrical Transmission, 7 transmission routes were assessed as part of the Project. The interconnection voltage is 230 kilovolts (kV) and the new transmission line will be approximately 10 miles long, extending from the western edge of the Project Site to the north, and west to the north side of the substation. The natural gas line and fresh water line for sanitary use will enter the Project Site from the east after travelling northwest along Tupman Road, and after tying into the existing linear lines located near the intersection of Tupman Road and State Route 119 (SR 119). The Project's brackish process water will be supplied by one of the local water districts and will enter the Project Site from the north. A possible additional source of raw water is proposed to come from the city of Bakersfield's wastewater treatment plant, which is approximately 10 miles to the east. This raw water pipeline will also travel west along SR 119 and northwest along Tupman Road to the Project Site. At this time this is not a viable option because all available water is already under contract to other parties.

An additional natural gas service provider with an interconnection point near the city of Taft was considered as a source of fuel for the Project. This alternative was eliminated because of the potential additional environmental impacts associated with the longer pipeline route.

The geology at the Project Site has been determined to be suitable for power plant construction. The geology in the vicinity of the Project Site has been determined to be suitable for carbon dioxide injection for enhanced oil recovery and sequestration and for injection of wastewater.

The Project Site location is optimal because of its proximity to a specific carbon dioxide customer. Due to this close proximity, the Project has designed a short pipeline with minimal environmental impact. The carbon dioxide pipeline passes through land owned by only two land owners.

The Project Site is in a lowly populated area. There are only a few homes within a mile of the Project Site and the unincorporated community of Tupman is approximately 2 miles from the site. The Project is designed to minimize the potential noise impact on sensitive receptors through prudent equipment location and noise abatement techniques.

Several alternative sites in the vicinity of Buttonwillow and Tupman were considered. However, they were rejected for various reasons, including (1) proximity to residences and businesses, (2) topography, (3) distance from the proposed carbon dioxide injection point, and/or (4) active agricultural status.

The Project Site was also chosen for its close proximity to Interstate 5 and State Routes 58 and 119. While SR 119 is not the preferred access route for the Project, it provides another major personnel ingress/egress route in the event an emergency. Primary access will be from State Route 58, which currently has sufficient operating capacity to support the Project with minimal mitigation, as discussed in Section 5.10, Traffic and Transportation. Alternative sites were located up to 15 miles further from these major highways and state routes.

The Project Site is located adjacent to the Elk Hills Oil Field Unit, which minimizes the number of land owners at the Project Site as well as the parcels surrounding the Project Site. In addition, the Project Site is currently owned by Occidental of Elk Hills Inc., which is interested in the carbon dioxide product that the Project will produce. Therefore, the feasibility of land access is maximized at the proposed Project Site location. Whereas, alternative identified sites involved several land owners.

Ease of land acquisition for the linear facilities will also be maximized with the proposed Project Site. The water supply pipeline will be located within an existing right of way owned by Buena Vista Water Storage District, therefore limiting the number of land owners the Project will have to negotiate with to build the water supply pipeline. The natural gas and potable water pipelines are primarily located within the existing Tupman Road right of way, also limiting the number of land owners the Project will have to negotiate with. And finally, both transmission line alternatives assessed in the AFC have been sited to limit the number of miles of transmission and number of land owners the Project will impact. Alternative sites assessed by the Applicant involved much longer linear facilities and would have resulted in more impact to existing land owners.

In conclusion, a thorough review of alternative sites and linear facilities locations was conducted. These sites and the relevant information are present in Table 6-1, Alternative Sites Reviewed and Status below.

Table 6-1
Alternative Sites Reviewed and Status

Property	Contact	Status
Project Site	Rick Peace, White Wolf Land Services	Project Site -- Submitted in the AFC
Site 2	Rick Peace, White Wolf Land Services	Work continuing to evaluate the property as an alternative site.
Site 3	Rick Peace, White Wolf Land Services	Work continuing to evaluate the property as an alternative site.
Site 4	Rick Peace, White Wolf Land Services	Rejected - Part of Coles Levee Ecosystem.
Site 5	Rick Peace, White Wolf Land Services	Rejected - Length of linears, Lokern Natural Area
Site 6	Rick Peace, White Wolf Land Services	Rejected - Length of linears, Lokern Natural Area
Site 7	Rick Peace, White Wolf Land Services	Rejected - Length of linears, Lokern Natural Area
Site 8	Rick Peace, White Wolf Land Services	Rejected - Length of linears, Lokern Natural Area
Site 9	Rick Peace, White Wolf Land Services	Rejected - Length of linears, Lokern Natural Area
Site 10	Rick Peace, White Wolf Land Services	Rejected - Length of linears, Lokern Natural Area
Site 11	Rick Peace, White Wolf Land Services	Rejected - Length of linears, Lokern Natural Area
Site 12	Rick Peace, White Wolf Land Services	Rejected - Length of linears, Land conditions
Site 13	Rick Peace, White Wolf Land Services	Rejected - Proximity to Buttonwillow and suitability of property for Project design
Site 14	Rick Peace, White Wolf Land Services	Rejected - Proximity to Buttonwillow and Interstate 5
Site 15	Rick Peace, White Wolf Land Services	Rejected - Proximity to Buttonwillow

Alternative site numbers 4 through 15 were rejected in favor of the proposed Project Site and linear facility locations. Based on the above-analysis, the Project Site was selected because it satisfied the basic Project Objectives, as described in Section 2.0, Project Description.

6.4 ALTERNATIVE GENERATING TECHNOLOGIES AND CONFIGURATIONS

HEI was formed to develop a material business consisting of the production of hydrogen fuel for the generation of low carbon power. Accordingly, the Project being proposed will generate baseload low carbon power using hydrogen-rich fuel produced from solid feedstock. The Project has two objectives that guide technology selection: (1) proving commercial scale Integrated Gasification Combined Cycle (IGCC)-with carbon-capture operability, and (2) proving associated economic viability. A key aspect is delivering a high reliability operating plant within a minimum period after initial startup.

6.4.1 General Electric Gasification Technology

IGCC with carbon capture is the only technology which meets the overall goal of the Project to generate low carbon power using hydrogen-rich fuel produced from a solid feedstock. Other technologies such as pulverized coal technology and oxyfuel technology do not meet this goal. Furthermore pulverized coal technology with carbon capture is an unproven technology at the Project's scale, has lower efficiency, higher water usage, and higher emissions.

General Electric's (GE) gasification technology forms the initial section of the IGCC power plant. Other gasification technology options were considered, including those of Shell and ConocoPhillips. GE's quench gasification process was selected for the following reasons:

- GE has the greatest experience of designing solid fuel gasifiers (GE had more than 10 operating facilities at the time of selection, which is more than ConocoPhillips or Shell).
- GE historically has the greatest operating experience with 100 percent petroleum coke gasifiers (four at the time of selection, compared to two for ConocoPhillips and none for Shell).
- The quench gasification process has the lowest capital cost.
- The quench gasification process is best suited for high levels of carbon dioxide capture because of a simple arrangement whereby the steam required by the shift reaction to produce carbon dioxide is generated by water quench of the synthesis gas (syngas).

Because of its proven solid feed quench gasifier design, GE is the selected technology supplier.

6.4.2 Acid Gas Removal System

Two important design criteria for the acid gas removal (AGR) system were (1) to remove sulfur in the hydrogen-rich fuel to a target of less than 5 ppm by volume (ppmv) total sulfur (a level compatible with state-of-the-art SCR technology), and (2) to produce a high purity carbon dioxide stream that contains over 90 percent of the total carbon in the raw syngas. There are numerous AGR technologies available but only a few have found wide-spread acceptance for gasification projects. The three most commonly selected technologies are methyldiethanolamine (MDEA), Selexol™, and Rectisol®.

For the reasons discussed below, Rectisol was selected because of its ability to meet the Project's target levels for sulfur removal and purity of the carbon dioxide stream. All three of these solvents are capable of selective removal of hydrogen sulfide from a sour syngas stream. However, the sulfur slip (H_2S + COS) in the treated syngas is highest for MDEA (an order of magnitude higher than the desired target level). For this reason, MDEA did not meet the requirements of the Project.

Selexol is commonly selected for IGCC applications where the gasifier pressure is relatively high and where the depth of sulfur removal is sufficient to allow the use of conventional selective catalytic reduction (SCR) catalysts in the heat recovery steam generators (HRSG). There are several Selexol units in commercial operation treating syngas. However, Selexol loses its capital cost advantage when either very deep sulfur removal or high-purity carbon dioxide capture is required, as are here. Furthermore, as compared with Rectisol, only one Selexol plant is understood to be operating at sulfur levels less than 5 ppmv in the hydrogen-rich gas, a lower experience base compared to Rectisol.

Rectisol is the more common selection when the syngas is used for chemical manufacturing and when very deep sulfur removal is required. Rectisol solvent is often used in the production of commercial grade methanol and is low cost and available from multiple suppliers. Rectisol is commercially proven on many power plants at sulfur levels lower than the desired target specification and there are over 50 Rectisol plants in operation. Another important factor in its selection is the removal of trace contaminants, such as carbonyl sulfide (COS), hydrogen cyanide (HCN), ammonia (NH_3), mercaptans, mercury (Hg), iron (Fe) and nickel (Ni) carbonyls; and mixtures of benzene, toluene, and xylene (BTX).

As a result of the evaluation, the Project chose Rectisol as the AGR system. Its ability for very deep sulfur removal, proven operating experience of removing sulfur down to the Project's desired sulfur levels, and removal of trace contaminants resulted in its selection over Selexol.

6.4.3 General Electric 7FB Combustion Turbine

GE's 7FB was selected as the combustion turbine for the following reasons. The F class offers higher efficiency (>4%) than E class and GE has demonstrated more than 100,000 hours on F class turbines in syngas service at the SG-Solutions Wabash IGCC and the TECO Polk IGCC power plants. GE originally developed the 7FB combustion turbine for natural gas-fired combined cycle applications. The first commercial unit started operating in 2002 and there are now eight operating 7FB (60Hz) units in the U.S. with a total of greater than 20,000 hours of operation and four operating comparable 9FB (50 Hz) units in Europe with a total of greater than 15,000 hours of operation. As the 7FB unit is being adapted for different fuel service, rather than undergoing a fundamental redesign and resizing, scale-up is not a concern. GE will provide a full commercial offering for the 7FB turbines that includes performance guarantees on both hydrogen and natural gas.

In conclusion, a thorough review of alternative generation technologies and configurations was conducted. Based on this review, none of the alternatives satisfied the basic Project Objectives, as described in Section 2.0, Project Description, without resulting in increased adverse impacts to the environment or impaired project feasibility as compared to the proposed Project. As a result, the alternative generation technologies and configurations were rejected in favor of the proposed Project's generation technology.

6.5 ALTERNATIVE WATER SUPPLIES

Water supply for the Project is brackish groundwater from the Buena Vista Water Storage District (BVWSD). The Project studied several potential alternate water supplies for the Project, as well as potential technologies for reducing water demand. The Applicant used the following water supply evaluation criteria as a means of evaluating and ranking potential raw water alternatives, in addition to the general evaluation criteria above:

- Environmental impacts
- Beneficial impact to local groundwater quality and agriculture
- Economic feasibility

- Feasibility of land acquisition
- Proximity to raw water supply
- Minimization of the parasitic electrical demand

The alternatives that were evaluated are detailed in the following sections.

6.5.1 Municipal Effluent

The Project Site is located approximately 10 miles from the City of Bakersfield Wastewater Treatment Plant #3. This plant treats a large portion of the municipal effluent generated from the city of Bakersfield. The Project had discussions with the city regarding their interest and availability in supplying water to the power plant. Currently, the city is selling its treated effluent to local farmers for irrigation purposes. They do not have excess capacity outside of existing contracts which can supply the Project with its total water needs. They do have some excess production (approximately 1 million gallons per day [mgd]), which is expected to increase in the intervening time between Project permit submission and startup. This growth rate is estimated at approximately 0.25 mgd per year, resulting in another 1 to 2 mgd available by startup in 2014. The Project will continue working with the city to advance this option.

6.5.2 Produced Water

Produced water refers to water that is "co-produced" from the many oil wells in the Kern County region. Kern County oil well output is often 8 parts water to 1 part oil, leading to a large excess of produced water, which the local oil producers must dispose of. Producers of these waters have indicated they are willing to sell their water to the Project at prices considered to be reasonable.

Valley Waste Disposal Company and Occidental of Elk Hills Inc. have indicated there is approximately 15 mgd of produced water available within 10 miles from the Project Site. Given the quality and ionic constituents of these supplies, the optimal technology for processing this raw water to Project standards is a "thermal process," using a mechanical vacuum pump and heat input to boil the water and recover a good quality stream sufficient for utility purposes. This utility water stream will then need to be treated further with reverse osmosis (RO) and demineralization to achieve the Project demineralized water standard. Unfortunately, while the quantity seems sufficient, there are several significant drawbacks to this supply:

1. The thermal processing technology will produce a concentrated brine waste stream. Based upon quality data already obtained, it is possible that this reject stream will have constituents at sufficient levels to trigger classification of the brine waste stream as hazardous waste. This would result in the Project acquiring a waste management problem which the base case does not present.
2. The capital and operating costs for a water plant to process this raw water supply is substantial and negatively impacts the Project's economics.
3. Produced water availability is dependant on the vagaries of local oilfield production, and, therefore, is an unpredictable supply. Local produced-water suppliers will not agree to contracts that include guarantee of supply. In terms of operations management, this stream is not as reliable as the Project's option.

Based on the above information, oilfield produced water has not been selected as part of the water supply for the Project.

6.5.3 Air Cooling

Air cooling of the steam turbine exhaust has been evaluated by the Project to determine suitability of air cooling for Project heat rejection. The resultant study of this option is included in Appendix O, water resources information. Air cooling of the STG has not been selected because it results in a substantial increase in parasitic electrical demand, an increase in capital costs, and a dramatic decrease in STG output. All of these effects result in a markedly negative impact on cost and availability of electricity. The results for air cooling the STG cycle drop power plant output by greater than 25 MW on hot days. Furthermore, while air cooling the air separation unit (ASU) is not unprecedented, air cooling the carbon dioxide compression intercoolers is unprecedented and presents significant technical risk to the Project. Based on the large negative commercial impact of lost production and the high degree of technical risk, air cooling threatens the feasibility of the Project and has not been included on that basis.

In conclusion, a thorough review of alternative water supplies was conducted. Based on this review, none of the alternatives satisfied the basic Project Objectives, as described in Section 2.0, Project Description, without resulting in increased adverse impacts to the environment or impaired project feasibility as compared to the proposed Project. As a result, the alternative water supplies were rejected in favor of the water supply chosen for the proposed Project.

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DATA ADEQUACY WORKSHEET

Adequacy Issue: Adequate ____ Inadequate ____ Revision No. 0 Date ____

Technical Area: **Alternatives** Project: ____ Technical Staff: ____

Project Manager: ____ Docket: ____ Technical Senior: ____

Siting Regulations	Information	AFC Page Number And Section Number	Adequate Yes Or No	Information Required To Make AFC Conform With Regulations
Appendix B (b) (1) (D)	A description of how the site and related facilities were selected and the consideration given to engineering constraints, site geology, environmental impacts, water, waste and fuel constraints, electric transmission constraints, and any other factors considered by the applicant.	Section 6.3 Section 6.5		
Appendix B (f) (1)	A discussion of the range of reasonable alternatives to the project, or to the location of the project, including the no project alternative, 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 an evaluation of the comparative merits of the alternatives. In accordance with Public Resources Code section 25540.6(b), a discussion of the applicant's site selection criteria, any alternative sites considered for the project, and the reasons why the applicant chose the proposed site.	Section 6.2 Section 6.3 Section 6.5		
Appendix B (f) (2)	An evaluation of the comparative engineering, economic, and environmental merits of the alternatives discussed in subsection (f)(1).	Section 6.2 Section 6.3 Section 6.5		