CHAPTER EIGHT
ALTERNATIVES

8.0 ALTERNATIVES

8.1 INTRODUCTION

The California Environmental Quality Act (CEQA) requires consideration of “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” [14 CCR 15126.6(a)]. Thus, the focus of an alternatives analysis should be on alternatives that “could feasibly accomplish most of the basic objectives of the project and could avoid or substantially lessen one or more of the significant effects” [14 CCR 15126.6(c)]. The CEQA Guidelines further provide that “[a]mong the factors that may be used to eliminate alternatives from detailed consideration in an EIR are: (i) failure to meet most of the basic project objectives, (ii) infeasibility, or (iii) inability to avoid significant environmental impacts” [14 CCR 15126.6(c)].

A range of reasonable alternatives that could feasibly attain most of the basic objectives of the proposed SGGS are identified and evaluated in this section. These include:

- The “No Project” alternative (that is, not developing a new power generation facility);
- Alternative site locations for constructing and operating the SGGS within the historic property boundaries of the EGS Property; and
- Alternative generation technologies.

8.2 PROJECT OBJECTIVES

SGPG has identified several basic objectives for the development of a power project. These objectives include:

- To construct and operate a 656-MW, natural-gas-fired, combined-cycle generating facility specifically designed to serve electricity demand in the Southern California region.
- To provide competitively priced electricity for sale to electric service providers.
- To construct a facility at a Reliant Energy-owned or controlled property to maximize the value of the public and private investment in the existing infrastructure.
- To help meet expected electrical demand growth in Southern California, including rapidly growing portions of San Bernardino and Riverside counties.
- To generate power at a location near the electric load, increasing reliability of the regional electricity grid and reducing regional dependence on imported power.
- To build new generation to coincide with the planned expansion of the transmission delivery system.
- To safely produce electricity and to do so without creating significant environmental impacts.

8.3 NO PROJECT ALTERNATIVE

8.3.1 Description

If the No Project Alternative is selected, SGPG would not receive authorization to construct and operate a new power generation facility. Electricity required for local reliability and peaking requirements that would have been produced by the SGGS would need to be generated by another source and/or imported to southern California. If the project is not constructed, other sources including older power generation facilities that may operate less efficiently than the proposed facility may be called upon to operate more frequently to serve the growing demand.

The State of California has projected a shortfall in peak load power supply for the Southern California region. The No Project Alternative would not assist the State in meeting this projected peak load demand. The No Project Alternative does not meet the objectives to produce efficient cost-competitive electricity that will increase grid reliability and reduce dependence on imported power.

8.3.2 Potential Effects of No Project Alternative

The No Project Alternative would result in the loss of a substantial new local property tax revenue source and other local economic benefits that would be created by the construction and operation of the SGGS. In addition, the No Project alternative could result in greater fuel consumption and air pollution if older, less-efficient plants with higher air emissions are used to meet future demand that could be provided by the proposed SGGS. Other less than significant environmental impacts, which may be attributed to the SGGS if constructed, would not occur with the No Project Alternative.

8.4 PROPOSED AND ALTERNATIVE SITES

8.4.1 Alternative Site Selection Criteria

The proposed SGGS project site is within the existing EGS site and would be constructed immediately west of the existing power generating facilities. The proposed site is currently occupied by cooling towers associated with retired Units 1 and 2 that will be removed by the EGS prior to construction of the SGGS in accordance with Reliant Energy's previous demolition plans. Construction of the new facility on the preferred site would capitalize on the close proximity to the new Rancho Vista Substation planned to be constructed and in service in 2009 by SCE. As part of the new Rancho Vista Substation, SCE will also be making downstream transmission upgrades that make the SGGS sited at an ideal location to deliver power that can more readily be distributed locally, where high future demand is forecasted. Additionally, locating the SGGS within the boundaries of the existing EGS site would allow the sharing of infrastructures such as the water supply system, fire loop, access roads and natural gas interconnections. Siting the SGGS in its present location would have the additional advantage of minimizing offsite transmission facilities to one single circuit transmission line with an off-site linear length of approximately 400 feet.

According to Public Resource Code 25540.6(b), evaluation of alternative sites is not required when a natural gas-fired thermal power plant is proposed for development at an existing industrial site and the project has a strong relationship to the existing industrial site. The SGGS is exactly the type of project that was envisioned by this code section; therefore, it is reasonable not to analyze alternative sites for the project. The SGGS would share infrastructure with the EGS, would be owned by the same parent corporation, would be close to the planned Rancho Vista Substation and through its strong relationship with the EGS site would minimize offsite linear features.

Because of these strong relationships, evaluation of alternative sites outside the boundaries of the EGS is not legally required. However, in order to provide some level of information to the CEC Staff and in accordance with pre-filing guidance from CEC Staff, a description of some local industrial sites has been provided.

8.4.2 Onsite Alternative Configurations Considered

8.4.2.1 Proposed Configuration

The proposed configuration is a 2 on 1 combined cycle base load plant with duct firing to deliver additional power during times of peak electrical demand. The location of the SGGS as configured was dictated by space requirements. The identified location for the SGGS is the only location within the EGS boundaries that could support a baseload plant of this size.

8.4.2.2 Repower Units 1 and 2

SGPG considered repowering Units 1 and 2 at the EGS. These units were retired in 2003 and their SCAQMD Permits To Operate surrendered. This configuration was rejected because repowering could not achieve the objective of creating new baseload generation greater than 600 MW, which SGPG believes is necessary to support future demand in the region. Additionally, this option was less economical than the proposed configuration. Because Units 1 and 2 are located closer to the nearest residence than the proposed project site, repowering Units 1 and 2 would place the facility closer to sensitive receptors.

8.4.2.3 Demolition of Units 1 and 2 and Replacement

SGPG considered demolishing Units 1 and 2 in order to construct a new baseload facility with a capacity greater than 600 MW in the location currently occupied by Units 1 and 2. However, this configuration would also place the new facility closer to sensitive receptors and with the cost of demolition and space constraints this option was less economical than the proposed configuration. Therefore this option was rejected.

8.4.2.4 Replacement of Units 3 and 4

SGPG considered replacement of Units 3 and 4. The existing capacity of Units 3 and 4 is 640 MW. The units are contracted to SCE under a Regulatory Must Run Contract. The loss of the capacity of Units 3 and 4, both during construction of a new replacement project and after, would result in a net loss of new needed generation. This configuration would also result in a net loss in value of the existing assets. Therefore this configuration was rejected.

8.4.2.5 3 on 1 Combined Cycle

SGPG also considered the feasibility of constructing a larger 3 on 1 combined cycle plant but it was rejected due to insufficient space on the EGS site.

8.4.3 Offsite Industrial Sites Considered

Several currently vacant properties were examined as possible locations for the proposed project that would reduce or eliminate environmental effects of the proposed project.

A large piece of vacant land lies on the north side of Jurupa Avenue between Beach and Poplar, approximately 6 miles southwest of the proposed project site. It would require offsite connections to transmission lines and a gas pipeline, and would require additional construction because of the lack of availability of shared facilities. This site also lies immediately adjacent to a residential community and in close proximity to two neighborhood parks — Catawba Park and Village Park, located south of this property. This site would not reduce any unmitigated impacts associated with development on the preferred site.

A closer site in a more industrial location north of Valley Boulevard between Commerce Drive and Calabash was also evaluated. This site would lie between existing industrial/commercial buildings a short distance east of Etiwanda Avenue, slightly less than 3 miles from the proposed project site. It would also provide a more direct route for construction traffic traveling from I-10 to the site. It would require offsite connections to transmission and a slightly longer lateral to connect to existing gas pipelines. It has no apparent advantages over the proposed project site, would require additional construction because of the lack of availability of shared facilities, and would not reduce any unmitigated impacts associated with development on the preferred site.

A third site lies across from the existing EGS on the east side of Etiwanda Avenue. This would be an irregularly shaped, elongated parcel running east/west along the north side of Napa Street and extending on its eastern extent up to the railroad bordering the proposed project site on its north. This alternative site is the closest site to the planned Rancho Vista substation and would have fewer offsite laterals than other alternatives considered. This site lies within Etiwanda Wash and along a major access road for the California Speedway. Construction access would be difficult. As with the other alternatives examined, this site would require additional construction because of the lack of availability of shared facilities. It has no apparent advantages over the proposed project site and would not reduce any unmitigated impacts associated with development on the preferred site.

A fourth site is located on Arrow Route east of I-15 and south of the Foothills Boulevard ramps. This is located in an industrial/commercial area approximately 1.5 miles north of the proposed project site. Construction access would be primarily from I-15 instead of I-10. Offsite laterals to the planned Ranch Vista substation would be directly south but through a developed area before it reaches SCE property. Construction access would be difficult. Similar to the third site examined, this site would require additional construction because of the lack of availability of shared facilities. It has no apparent advantages over the proposed project site and would not reduce any unmitigated impacts associated with development on the preferred site.

All four of these site would have more visual impacts because they would not be located within an existing power plant facility, and would require additional land for certain stand-alone facilities such as emergency fire water. All would require additional offsite laterals as compared to the proposed project, and construction access would be difficult. There are no apparent environmental advantages to these alternatives, and several environmental disadvantages, as described above. For these reasons, these alternatives were rejected from further consideration

8.5 WATER SUPPLY

The CEC studied use of water for power plant cooling in its 2003 Integrated Energy Report Proceeding. The proceeding produced the following policy:

Consistent with the Board Policy[1] and the Warren-Alquist Act, the Energy Commission will approve the use of fresh water for cooling purposes by power plants which it licenses only where alternative water supply sources and alternative technologies are shown to be "environmentally undesirable" or "economically unsound" (CEC, 2003).

[1] This reference is to SWRCB Policy 75-58.

The SGGS would be a dry cooled facility and would use very little water. The source of the process water would be the existing EGS makeup water system reservoir, which primarily contains reclaimed water delivered by the Inland Empire Utilities Agency. Since the SGGS would use dry cooling technology and reclaimed water, no alternative water supply analysis is required to demonstrate compliance with the policies identified in the 2003 IEPR.

Potable water would be generated on site using water from the existing EGS potable water system. Since both the interconnections to the process water supply and the potable water supply would occur within the boundaries of the existing EGS site, no alternative water pipelines were considered.

8.6 WASTE DISPOSAL

The SGGS would have a sanitary sewer system on site. Process wastewater would be discharged into the existing wastewater disposal system currently serving the EGS. Since the interconnection for process wastewater would be on site no alternative wastewater pipelines were considered.

8.7 ELECTRIC TRANSMISSION LINES

The SGGS would interconnect at the planned SCE Rancho Vista Substation, which will be located just south of the EGS property. Since the SGGS transmission line would be very short and essentially in a straight corridor between the SGGS and the planned Rancho Vista Substation, no alternative transmission line routes were considered.

8.8 NATURAL GAS SUPPLY LINE

The SGGS natural gas pipeline would interconnect just outside the existing EGS boundary and immediately adjacent to Etiwanda Avenue. Since the gas pipeline interconnection is so short, no alternative gas pipeline routes were considered.

8.9 ALTERNATIVE AIR POLLUTION EMISSION CONTROL ANALYSIS

The proposed project must comply with the requirements of the South Coast Air Quality Management District's (SCAQMD's) permit regulations requiring the application of the Best Available Control Technology (BACT) to control air emissions. To comply with the SCAQMD's BACT requirements for oxides of nitrogen (NO_x), the project's design includes dry low NO_x combustion controls on the gas turbine and selective catalytic reduction (SCR) to control NO_x emissions. To comply with SCAQMD's BACT requirements for carbon monoxide (CO) a CO catalyst would be employed. The SCR technology proposed for SGGS uses a 29.4 percent solution of ammonia to reduce NO_x emissions to elemental nitrogen, water, and a small quantity of unreacted ammonia. However, the use and storage of ammonia—even the less toxic aqueous ammonia proposed for the SGGS—would represent a potential risk to the public in the event of a catastrophic breach of the storage tank. The offsite consequence analysis (presented in Section 7.12, Hazardous Materials Handling) shows that the potential impacts associated with the project's use and storage of ammonia would not result in a significant public health impact.

To provide a comprehensive analysis of the alternative project configuration, the remainder of this section presents alternative NO_x emission control technologies considered for the project. The information presented below is based on the air quality analysis presented in Section 7.1, Air Quality.

Potential NO_x control technologies for combustion gas turbines include the following:

- Combustion controls
  - Dry combustion controls

  - Dry low-NO_x combustor design
  - Catalytic combustors (e.g., XONON)

- Post-combustion controls
  - Selective non-catalytic reduction (SNCR)
  - Non-selective catalytic reduction (NSCR)
  - SCONOx^{TM}

The technical feasibility of available NO_x control technologies are presented below.

8.9.1 Combustion Modifications

8.9.1.1 Dry Combustion Controls

Combustion modifications that lower NO_x emissions without wet injection include lean combustion, reduced combustor residence time, lean premixed combustion, and two-stage rich/lean combustion. Lean combustion uses excess air (greater than stoichiometric air-to-fuel ratio) in the combustor's primary combustion zone to cool the flame; thereby, reducing the rate of thermal NO_x formation. Reduced combustor residence times are achieved by introducing dilution air between the combustor and the turbine sooner than with standard combustors. The combustion gases are at high temperatures for a shorter time, which also has the effect of reducing the rate of thermal NO_x formation. Dry low NO_x combustion would be used on the Siemens 5000F gas turbine for this project.

Catalytic combustors use a catalytic reactor bed mounted within the combustor to burn a very lean fuel-air mixture. This technology has been commercially demonstrated under the trade name XONON in a 1.5-MW natural gas-fired combustion turbine in Santa Clara, California. The technology has not been announced commercially for the engines used at SGGS. No turbine vendor, other than Kawasaki, has indicated the commercial availability of catalytic combustion systems at the present time; therefore, catalytic combustion controls are not available for this specific project and are not discussed further.

8.9.1.2 Wet Combustion Controls

Steam or water injection directly into the turbine combustor is one of the most common NO_x control techniques. These wet injection techniques lower the peak flame temperature in the combustor, reducing the formation of thermal NO_x. The injected water or steam exits the turbine as part of the exhaust. Although the lower peak flame temperature has a beneficial effect on NO_x emissions, it can also reduce combustion efficiency and prevent complete combustion. As a result, carbon monoxide (CO) and volatile organic compounds (VOCs) emissions increase as water/steam injection rates increase.

Water and steam injection have been in use on both oil- and gas-fired combustion turbines in all size ranges for many years, so these NO_x control technologies are generally considered technologically feasible and widely available. Since dry low NO_x combustion controls are utilized in the Siemens 5000F gas turbines and are more effective than water injection, water injection is not considered for this project.

8.9.1.3 Post-Combustion Controls

Selective catalytic reduction is a post-combustion technique that controls both thermal and fuel-bound NO_x emissions by reducing NO_x with a reagent (generally ammonia or urea) in the presence of a catalyst to form water and nitrogen. NO_x conversion is sensitive to exhaust gas temperature, and performance can be limited by contaminants in the exhaust gas that may mask the catalyst (sulfur compounds, particulates, heavy metals, and silica). SCR is used in numerous gas turbine installations throughout the United States, almost exclusively in conjunction with other wet or dry NO_x combustion controls. SCR requires the consumption of a reagent (ammonia or urea) and requires periodic catalyst replacement. Estimated levels of NO_x control are in excess of 90 percent. SCR would be utilized on this project in conjunction with the dry low NO_x combustion controls on the Siemens 5000F gas turbine.

Selective non-catalytic reduction (SNCR) involves injection of ammonia or urea with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1,200 to 2,000°F and is most commonly used in boilers. Some method of exhaust gas reheat, such as additional fuel combustion, would be required to achieve exhaust temperatures compatible with SNCR operations, and this requirement makes SNCR technologically infeasible for SGGS.

Nonselective catalytic reduction (NSCR) uses a catalyst without injected reagents to reduce NO_x emissions in an exhaust gas stream. NSCR is typically used in automobile exhaust and rich-burn stationary internal combustion (IC) engines, and employs a platinum/rhodium catalyst. NSCR is effective only in a stoichiometric or fuel-rich environment where the combustion gas is nearly depleted of oxygen, and this condition does not occur in turbine exhaust where the oxygen concentrations are typically between 14 and 16 percent. For this reason, NSCR is not technologically feasible for the SGGS.

SCONOx™ is a proprietary catalytic oxidation and adsorption technology that uses a single catalyst for the control of NO_x, CO, and VOC emissions. The catalyst is a monolithic design, made from a ceramic substrate with both a proprietary platinum-based oxidation catalyst and a potassium carbonate adsorption coating. The catalyst simultaneously oxidizes NO to NO_2, CO to CO_2, and VOCs to CO_2 and water, while NO_2 is adsorbed onto the catalyst surface where it is chemically converted to and stored as potassium nitrates and nitrites. The SCONOx potassium carbonate layer has a limited adsorption capability and requires regeneration approximately every 12 to 15 minutes in normal service (see Section 7.1, Air Quality, for details). Each regeneration cycle requires approximately 3 to 5 minutes. At any point in time, approximately 20 percent of the compartments in a SCONOx system would be in regeneration mode, and the remaining 80 percent of the compartments would be in oxidation/absorption mode.

There are serious questions about the probability of a successful application of the SCONOx technology for application to SGGS, as well as the levels of emission control that can be consistently achieved. Therefore, this technology is not considered feasible for SGGS.

8.9.2 Alternatives to Ammonia-Based Emission Control Systems

Over the last few years, several vendors have designed urea-based systems to generate ammonia onsite, thereby eliminating the need to transport and store ammonia. These units are referred to as Ammonia on Demand (Environmental Elements Corporation) and Urea to Ammonia (EC&C Technologies Incorporated). However, on September 9, 2003, a permanent injunction was issued against Environmental Elements Corporation, barring the company from selling or manufacturing the Ammonia on Demand system due to patent infringement on EC&C Technologies Inc. Therefore, only EC&C's Urea to Ammonia (U2A) system is commercially available.

The U2A system generates ammonia from solid dry urea. The process starts by dissolving urea in deionized water to produce an aqueous urea solution. Steam is used in the U2A reactor to convert the urea solution into a gaseous mixture of ammonia, carbon dioxide, and water for use in the SCR system.

The U2A technology was first commercially installed on AES's Alamitos Generating Station (AGS) Unit 6, in Long Beach California, as a demonstration project. Unit 6 is a utility boiler that had an existing SCR system that used and stored ammonia. The U2A technology replaced the ammonia storage tank. Based on a successful demonstration of the U2A at AGS, AES contracted for the permanent installation of two U2A systems at its Huntington Beach Generating Station (HBGS) in Huntington Beach, California.

The U2A system would not be cost effective for the SGGS because the SGGS ammonia system would be too small and ammonia is already transported to the EGS site.

8.10 ALTERNATIVE TECHNOLOGIES

Other generation technologies considered for the project are grouped according to the fuel used:

- Oil
- Coal
- Nuclear
- Hydroelectric
- Biomass
- Solar
- Wind

Alternative technologies were evaluated with respect to commercial availability, implementability and cost-effectiveness.

8.10.1 Oil, Coal, and Conventional and Supercritical Boiler/Steam Turbine

These technologies are commercially available and could be implemented. However, because of relatively low efficiency, some of these fuels or technologies may emit a greater quantity of air pollutants per kilowatt-hour generated than technologies that are more efficient. Space requirements, water usage, and the cost of generation for these alternative technologies is relatively high compared to combined-cycle/natural gas-fired technologies.

8.10.2 Nuclear

California law prohibits new nuclear plants until the scientific and engineering feasibility of disposal of high-level radioactive waste has been demonstrated. To date, the California Energy Commission (CEC) is unable to make the findings of disposal feasibility required by law for this technology to be viable in California. This technology, therefore, is not possible at this time.

8.10.3 Water

These technologies use water as "fuel," and include hydroelectric, geothermal, and ocean energy conversion.

8.10.3.1 Hydroelectric

Most of the sites for hydroelectric facilities have already been developed in California, and the remaining potential sites face lengthy environmental licensing periods. It is doubtful that this technology could be implemented within 3 to 5 years, and the cost would probably be higher than the cost of a conventional simple-cycle. There are no hydroelectric sites within the project area.

8.10.3.2 Geothermal

Geothermal development is not viable at the project location because suitable thermal resources and strata are not present. Therefore, it was eliminated from consideration.

8.10.4 Biomass

Major biomass fuels include forestry and mill wastes, agricultural field crop and food processing waste, and construction and urban wood wastes. Their cost tends to be high relative to conventional combined-cycle units burning natural gas.

8.10.5 Solar

Most solar technologies collect solar radiation, heat water to create steam, and use the steam to power a steam turbine/generator. Power is only available while the sun shines so the units may not be available to meet demand swings. The cost of solar power is relatively high when compared to combined-cycle units burning natural gas.

8.10.6 Wind Generation

In California, the average wind generation capacity factor has been 25 to 30 percent and, like solar, may not be available to meet demand swings. The cost of generation is generally above the cost of simple-cycle units burning natural gas. There are no wind generation sites within the project area. In addition, the SGGS is configured not only to provide baseload capacity but has been specifically designed to duct fire and produce additional electricity during periods of high electricity demand whereas wind generation facilities rely on the presence of wind to produce electricity at any given time. In addition, wind turbines are significantly smaller in size than thermal power producing technologies; therefore, an extensive amount of real estate would be required to generate an equivalent amount of energy to that produced by the proposed SGGS.

8.11 REFERENCES

CEC (California Energy Commission), 2003. Integrated Energy Policy Report. December.