CH2M HILL
2485 Natomas Park Drive
Suite 600
Sacramento, CA 95833-2937
Tel 916.920.0300
Fax 916.920.8463

CH2MHILL

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371322

Rod Jones
1516 Ninth Street
Sacramento, CA 95814-5512

Subject: Lodi Energy Center (08-AFC-10)
Supplement D –Changes to Equipment and Project Fenceline

Dear Mr. Jones:

Please find attached the Lodi Energy Center's Supplement D – Changes to Equipment and Project Fenceline. This supplement was prepared as a result of a change in the turbine vendor and some minor modifications to the project fenceline.

Attached are 60 hard copies and 65 electronic copies on CD-ROM. Five electronic copies of the revised Air Quality modeling files on CD-ROM have also been included with this package.

If you have any questions about this matter, please contact me at (916) 286-0249 or Andrea Grenier at (916) 780-1171.

Sincerely,

CH2M HILL

Sarah Madams
Project Manager

Attachment

cc: A. Grenier, Grenier & Associates, Inc.
E. Warner, NCPA

Application for Certification

Supplement D

Changes to Equipment and Project Fenceline

Lodi Energy Center

July 2009

EY062008001SAC

Submitted by

NCPA
NORTHERN CALIFORNIA POWER AGENCY

Submitted to

California Energy Commission

With Technical Assistance by

CH2MHILL

Supplement D

Changes to Equipment and Project Fenceline

In support of the

Application for Certification

for the

Lodi Energy Center Project

Lodi, California

(08-AFC-10)

Submitted to the:

California Energy Commission

Submitted by:

NCPA

NORTHERN CALIFORNIA POWER AGENCY

With Technical Assistance by:

CH2MHILL

Sacramento, California

July 2009

Contents

1.0 Introduction

Upon completion of Northern California Power Agency's (NCPA) Application for Certification (AFC) submittal for the Lodi Energy Center Project (LEC), NCPA began the public works process for the procurement of the power island equipment for the project. As a result of the public works process, NCPA entered into a purchase agreement with Siemens for the power island equipment, which includes the combustion turbine generator (CTG) and associated equipment. In its AFC, NCPA identified the "Rapid Response" GE Energy Frame 7FA as the possible CTG equipment. In this Supplement, NCPA documents its final selection of the "Flex Plant™ 30", which includes a Siemens STG6-5000 natural-gas fired CTG, a Siemens SST-900RH single condensing steam turbine, and associated equipment.

The switch from GE to Siemens equipment will result in minor revisions to the general arrangement and environmental analysis that was provided in the AFC. In addition, the project site boundary to the east and south has been modified slightly as a result of discussions with local agencies. This Supplement has been structured specifically to help California Energy Commission (CEC) Staff easily understand what the changes are, why they are necessary, and how they will affect the environmental analysis contained in the original AFC. Tables have been included in the Supplement that: (1) summarize the major equipment and project changes, (2) describe the minor corrections and clarifications to the AFC, and (3) list the sections, figures, and appendixes that have been revised as a result of the project description changes discussed above.

It should be underscored that the majority of the project description modifications described in this Supplement affect only the air quality section of the AFC, and to that end, this Supplement includes a "road map" (found in Appendix C) showing specifically what has changed within the air quality section to aid Staff in easily identifying and understanding any resulting changes to air quality emissions and calculations.

2.0 Project Description Changes

The Applicant is proposing changes to the power generation equipment and project fenceline at the LEC, as shown in Figures 2.1-1R and 2.1-2R. In lieu of the "Rapid Response" GE Energy Frame 7FA proposed in the AFC, NCPA has selected a combined-cycle nominal 296-megawatt (MW)[1] Flex Plant 30power generation facility consisting of a Siemens STG6-5000F natural gas-fired CTG and a Siemens SST-900RH single condensing steam turbine. Due to the inherent design of the Siemens equipment, the heat recovery steam generator (HSRG) will no longer require supplemental firing. Additional project changes that result from the generating equipment changes are: (1) a reduction in the size of the auxiliary boiler; (2) a redesign of the plant cooling system, with resulting increases in the cooling tower water flow rate and maximum cooling water total dissolved solids (TDS); and (3) a change from a conventional triple pressure boiler that uses a high-pressure (HP) drum to a "Benson"-type triple-pressure boiler that utilizes a once-through HP section with no HP drum.

Although the plant's overall footprint and location have not changed appreciably from that provided in the AFC, further discussions with the City of Lodi and the San Joaquin Council of Governments (SJCOG) have resulted in a slight modification to the project fenceline. The eastern boundary of the plant will be moved approximately 30 feet closer to the base of the City of Lodi's White Slough Water Pollution Control Facility (WPCF) wastewater pond. The eastern boundary is being moved to accommodate an access road along the eastern border of the LEC as requested by the City of Lodi's Building Department. In addition, the southern boundary of the plant has been adjusted slightly, and has been moved north to accommodate a required 30-foot buffer from the drainage canal located to the south of the proposed LEC. Based on conversations with the SJCOG staff, the 30-foot buffer is required because the southern portion of the project site is located in the upland habitat of the giant garter snake (*Thamnophis gigas*), a California and federal Threatened species.

For ease in understanding the project changes, Table 2-1 identifies the major equipment and project changes provided in this Supplement. Table 2-2 identifies minor corrections and clarifications to information provided in the AFC. Table 2-3 identifies the sections, figures, and appendixes that have been revised as a result of the project description changes discussed above. A copy of the complete revised project description in underline strikeout is provided as Appendix A. A copy of the complete revised design criteria is provided as Appendix B.

[1] Capacity at 61 degrees Fahrenheit is 296 MW.

TABLE 2-1
Modifications to Lodi Energy Center AFC Addressed in Supplement D

Modification	Reason for Change
Replaced GE "Rapid Response" turbine and associated equipment with Siemens' "Flex Plant™ 30" turbine and associated equipment	NCPA's public works procurement process has resulted in the selection of Siemens for this project.
Reduced auxiliary boiler size	The change in steam demand for Siemens equipment supports a smaller auxiliary boiler.
Increased cooling water flow rate and TDS	The HRSG proposed by Siemens is a "Benson" boiler that has no HP steam drum and therefore requires greater water throughput. Because the Title 22 water supplied by the City of Lodi's WPCF is high in chlorides, the water treatment process of this high throughput increases the inherent TDS in the cooling tower.
Replaced STIG cooling tower with heat exchanger	The heat exchanger provides improved efficiency. In addition, due to space constraints, the cooling tower for the STIG plant has been replaced with a heat exchanger.
Replaced hydrogen cooled combustion and steam generators with totally enclosed water-to-air cooled generator	Change in cooling design for Siemens equipment. As a result, hydrogen is no longer needed for the project.
Replaced three 50% circulating water pumps with two 100% circulating water pumps and a single 100% auxiliary cooling water pump	Refinement of project design
Revised water usage requirements from 709 acre-feet per year (afy) to a maximum of 1,800 afy	Siemens equipment has different water usage requirements than the originally indicated GE equipment.
Revised electrical one-line diagram to show two, 2-winding generator step-up transformers	Refinement of project design.
Removed discussion of duct burners	Siemens proposed HRSG has no duct burners.
Removed 230kV end structure on north side of property and replaced with 5 transmission poles on eastern boundary	Addition of continuous fire loop road required relocation of transmission line
Moved eastern boundary of project site 30 feet east	City of Lodi requires a continuous fire loop road around the LEC. By moving the road 30 feet to the east, additional space is obtained to make installation of the loop road possible.
Realigned southern boundary of plant slightly north	SJCOG requirement for a 30 foot buffer from the irrigation canal to the southern fenceline of the plant.

TABLE 2-2
Minor Clarifications and Corrections to Lodi Energy Center AFC

Modification	Reason for Change
Added 230-kV switchyard under “New or Modified Facilities”	The 230-kV switchyard will be modified by adding an additional breaker to accommodate the new LEC.
Deleted Water Balance “Calculation Cover Sheet”	Not required. All data is now shown on the water balance diagram.
Removed references to new admin/control/warehouse/ maintenance building	The LEC will use the existing admin/control/warehouse/ maintenance building already in place for the STIG plant. A new building is not proposed as part of this project.
Deleted reference to rotary screw air compressors	Typographical error. The compressors have not yet been purchased and could be reciprocating type.
Revised demineralized tank size to 200,000 gallons for a nominal 4.76 days of usage	Typographical error. AFC stated 20,000 gallons, but the tank is actually 200,000 gallons.
Corrected sanitary and domestic water usage to 50 gallons per day (gpd)	Typographical error. AFC stated 50 mgpd, but actual usage is 50 gpd.

TABLE 2-3
AFC Sections & Figure Modifications Made as a Result of Supplement

Modification	Reason for Change
Figures	
Figure 1.1-1R, Oblique Rendering	Equipment changes resulted in minor changes to the plant simulations. Equipment changes are only visible in the Oblique Rendering, KOP-1 and from KOP-2.
Figure 2.1-1R, General Arrangement	The Siemens equipment is different in type and size from the originally proposed GE equipment.
Figure 2.1-2R, Elevation Drawings	The elevation drawings have been revised to reflect the changes to the General Arrangement.
Figure 2.1-4AR, Heat Balance	The change to Siemens equipment resulted in a modification to the heat balance.
Figure 2.1-4BR, Heat Balance Table	The change to Siemens equipment resulted in a modification to the heat balance.
Figure 2.1-5AR, Water Balance – Annual Average	The water balance changed due to an increase in process water throughput required by the Siemens equipment.
Figure 2.1-5BR, Water Balance – Summer Peak	The water balance changed due to an increase in process water throughput required by the Siemens equipment.
Figure 3.2-1R, One Line Diagram	The one line diagram has been modified due to the change to Siemens equipment and different thermal efficiencies of the new equipment.
Figure 5.13-2R, KOP-1	Equipment changes resulted in minor changes to the plant simulations. Equipment changes are only visible in KOP-1, KOP-2, and the Oblique Rendering of plant.

TABLE 2-3
AFC Sections & Figure Modifications Made as a Result of Supplement

Modification	Reason for Change
Figure 5.13-3R, KOP-2	Equipment changes resulted in minor changes to the plant simulations. Equipment changes are only visible in KOP-1, KOP-2, and the Oblique Rendering of plant.
Figure 3.13-1, Fogging Frequency Curve	A Fogging Frequency Curve has been provided as a new figure.
AFC Sections	
Section 2.0, Project Description	The Siemens equipment is different in type from the originally proposed GE equipment, and requires minor changes to the Project Description chapter. A revised project description chapter is provided in underline/strike-out as Appendix A.
Section 5.1, Air Quality	As a result of the equipment change and small footprint modification, minor changes have been made to Section 5.1, Air Quality. A revised Air Quality chapter is provided in underline/strike-out as Appendix C.
Section 5.5, Hazardous Materials	As a result of the equipment change, minor changes were required for Section 5.5 Hazardous Materials. Hydrogen has been removed from the project, and sulfuric acid quantities have increased slightly. The changes were minor enough that a complete revision of the Hazardous Materials chapter was not required, and all revisions are provided in Section 3.5 of the Supplement.
Section 5.9, Public Health	As a result of the equipment change and small footprint modification, minor changes were required for Section 5.9 Public Health. The changes were minor enough that a complete revision of the Public Health chapter was not required, and all revisions are provided in Section 3.9 of the Supplement.
Section 5.15, Water Resources	As a result of the equipment change, and difference in water supply quantities, minor changes were required for section 5.15 Water Resources. The changes were minor enough that a complete revision of the Water Resources chapter was not required, and all revisions are provided in Section 3.15 of the Supplement.
AFC Appendixes	
Appendix 2.B - Revised, Design Criteria	The Siemens equipment is different in type and size from the originally proposed GE equipment, and required minor changes to the design criteria appendix provided in the AFC. A revised design criteria appendix is provided in underline/strike-out as Appendix B.
Appendix 2.D - Revised, Will-Serve Letter	The Siemens equipment requires a larger quantity of water to operate and therefore an updated Will Serve Letter has been obtained and is provided as Appendix F.
Appendixes 5.1 - Revised, Air Quality	As a result of the equipment change and small footprint modification, minor changes were required to the air quality appendixes provided in the AFC. The revised air quality appendixes are provided as Appendix D.
Appendixes 5.9 - Revised, Public Health	As a result of the equipment change and small footprint modification, minor changes were required for the public health appendixes provided in the AFC. The revised public health appendixes are provided as Appendix E.

3.0 Environmental Analysis of Proposed Change to the Project Description

The proposed project changes set forth in this Supplement do not affect most of the environmental analyses described in the AFC. An analysis of the effects of the proposed changes on each of the environmental areas is presented below. Additionally, laws, ordinances, regulations, and standards (LORS) contained in the AFC have been reviewed to determine if any LORS should be added or removed from the analysis as a result of the project description modifications.

3.1 Air Quality

The assessment of air quality impacts has been revised to reflect the following project design changes:

- Revised gas turbine/HRSG emissions and stack parameters to reflect change from GE to Siemens technology
- Elimination of duct firing operating cases
- Revised auxiliary boiler emissions and stack parameters to reflect change in size and operating hours
- Revised cooling tower emissions to reflect increased cooling water flow rate and increased TDS levels
- Adjustments to the equipment layout and facility fenceline

These changes affect the calculation of emissions from the project, the air quality impact analysis, and the mitigation requirements. Although the changes are not substantive, they do affect several parts of the air quality section. Therefore, for ease of review, a strikeout version of the entire air quality section is provided as Appendix C. Section and table numbering in the revised air quality section and appendix follow those of the original AFC. Revised tables are designated with an "R" in the table number. Revised appendixes for the air quality section are provided as Appendix D.

The revised air quality impact assessment demonstrates that the redesigned project will comply with all LORS. As a result, any potential air quality impacts associated with this Supplement will be less than significant.

3.2 Biological Resources

The proposed equipment change and modified footprint will have no effect on the biological resources analysis provided in the AFC. The area affected by the adjustment of the project fenceline was previously surveyed as part of the biological surveys conducted for the LEC project. The revised equipment change and modified footprint will not result in potential impacts greater than those analyzed in the AFC, and no LORS will change as a result of the modifications. Therefore, any potential biological resources impacts associated with this Supplement will be less than significant.

3.3 Cultural Resources

The proposed equipment change and modified footprint will have no effect on the cultural resources analysis provided in the AFC. The change in equipment will not require deeper excavations than those identified in the AFC. The area affected by the revised fenceline alignment was previously covered in the record searches and pedestrian surveys; as a result, there is no need to repeat or update the project's pedestrian surveys. The proposed equipment change and modified footprint will not result in potential impacts any different from those addressed in the AFC, and no LORS will change as a result of the modifications. Therefore, any potential cultural resources impacts associated with this Supplement will be less than significant.

3.4 Geologic Resources and Hazards

The proposed equipment change and modified footprint will have no effect on the geologic resources and hazards analysis provided in the AFC. Because the footprint of the site has had only minor changes, the proposed modification will not result in potential impacts greater than those analyzed in the AFC, and no LORS will change as a result of this modification. Consequently, any potential geological resources impacts associated with this Supplement will be less than significant.

3.5 Hazardous Materials Management

The chemical inventory for the LEC (Tables 5.5-1 through 5.5-3 in the Hazardous Materials section of the AFC) has changed as a result of the proposed equipment changes. Hydrogen will no longer be used on site and the amount of sulfuric acid used in the cooling towers has increased slightly from 3,000 gallons to 4,000 gallons. These changes are reflected in the revised hazardous materials tables (Tables 5.5-1R, 5.5-2R, and 5.5-3R) provided at the end of Section 3 of this supplement. The proposed equipment change and modified footprint will not result in any further modifications to the LEC chemical inventory, will not result in any potential impacts greater than those analyzed in the AFC, and no LORS will change as a result of this modification. Therefore, any potential hazardous materials management impacts associated with this Supplement will be less than significant.

3.6 Land Use

The proposed equipment change and fenceline modification will be consistent with existing and planned land uses in this area. The proposed modifications will not result in any potential impacts greater than those analyzed in the AFC, and no LORS will change as a result of these modifications. As a result, any potential land use impacts associated with this Supplement will be less than significant.

3.7 Noise and Vibration

The proposed equipment change and fenceline modification will not result in potential impacts greater than those analyzed in the AFC, and no noise LORS will change as a result of the modifications. Therefore, any potential noise and vibration impacts associated with this Supplement will be less than significant.

3.8 Paleontology

The proposed equipment change and fenceline modification will not create any additional paleontological impacts to the site. The change in equipment will not require deeper excavations than those identified in the AFC. The area affected by the revised fenceline alignment was previously surveyed during AFC preparation, and the proposed modification will not result in potential impacts greater than those addressed in the AFC, and no LORS will change as a result of the modifications. Therefore, any potential paleontological resources impacts associated with this Supplement will be less than significant.

3.9 Public Health

The screening health risk assessment (SHRA) for the project has been revised to reflect the proposed project changes, including changes in fuel use and resulting emissions, stack parameters, and plant layout. Additionally, the revised SHRA used the HARP model with the AERMOD and the California Air Resources Board (CARB) On-Ramp as well as the most current risk values from Office of Environmental Health Hazard Assessment and CARB. The results of the revised SHRA are summarized in Tables 3.9-1 and 3.9-2. Details of the revised SHRA are provided in Appendix E.

TABLE 3.9-1
Summary of Potential Health Risks

Receptor	Carcinogenic Risk [a] (per million)	Cancer Burden	Acute Health Hazard Index	Chronic Health Hazard Index
Maximum Incremental Cancer Risk (MICR) at PMI	0.45	0	0.01	0.006
Maximally Exposed Individual Worker [b] (MEIW)	0.074		n/a	n/a
Significance Level	10	1.0	1.0	1.0

[a]Derived (Adjusted) Method used to determine significance of modeled risks.

[b]The worker is assumed to be exposed at the work location 8 hours per day, instead of 24; 245 days per year, instead of 365, and for 40 years, instead of 70. Therefore, a 70 year-based chronic health hazard index is not applicable to a worker.

TABLE 3.9-2
Summary of Potential Cumulative Health Risks

Receptor	Carcinogenic Risk* (per million)	Acute Health Hazard Index	Chronic Health Hazard Index
Maximum Incremental Cancer Risk, LEC	0.45	0.01	0.006
Maximum Incremental Cancer Risk, Existing NCPA Lodi Power Plant	2.9	0.004	0.002
Maximum Cumulative Combined Cancer Risk	2.9	0.01	0.01
Significance Level	10	1.0	1.0

*Derived (Adjusted) Method used to determine significance of modeled risks. Residential (70-year) exposure shown.

3.10 Socioeconomics

The proposed equipment change and modified fenceline will not affect the construction workforce, nor will they result in any change in local purchases of materials or supplies. The cost of construction for the project as well as the proposed construction workforce remains identical to that provided in the AFC. Additionally, the changes will not affect the environmental justice analysis, because all project impacts will be mitigated to a less-than-significant level. Therefore, the proposed equipment changes and modified fenceline will not result in any potential impacts or benefits substantially greater than those analyzed in the AFC, and no LORS will change as a result of the modifications. As a result, any potential socioeconomics impacts associated with this Supplement will be less than significant.

3.11 Soils

Although the type of equipment has changed and the fenceline has been modified slightly, the construction of the plant will still use best management practices to minimize soil erosion. The proposed equipment changes and fencline modification will not result in any impacts different from those analyzed in the AFC, and no LORS will change as a result of the modifications. Therefore, any potential soil impacts associated with this Supplement will be less than significant.

3.12 Traffic and Transportation

The proposed equipment change and fenceline modification will not affect the construction workforce and, therefore, would not affect traffic impacts from those already addressed in the AFC. Also, no LORS will change as a result of the modifications. As a result, any potential traffic and transportation impacts associated with this Supplement will be less than significant.

3.13 Visual Resources

The proposed equipment change and fenceline modification will result in the minor relocation of some project equipment. The steam turbine generator power distribution center (PDC) has been combined with the HRSG PDC and the combined PDC now exists on the west side of the HRSG under the pipe bridge. These changes are minor, and do not result in larger equipment on site than what was originally identified in the AFC, however will require modification to some of the visual simulations of the plant. In addition to the minor equipment changes, with the incorporation of a continuous fire loop road around the property, the 230-kV end structure on the northern side of the property has been removed and replaced with five 75-foot-tall transmission poles on the eastern boundary.

As a result of the additional transmission poles, the minor equipment changes, and fenceline modification, a revised architectural rendering has been provided as Figure 1.1-1R. Also, as a result of these revisions, key observation points (KOP) 1 and KOP-2 have had minor changes and updated simulations are provided as Figures 5.13-2R and 5.13-3R. The remaining KOP figures provided in the AFC remain unchanged due to the distance from the location of photo to the proposed power plant site. Although the new poles are taller than some of the structures at the proposed plant, they are not the tallest equipment onsite. Additionally, the poles are shorter than the surrounding transmission line corridors adjacent to the project, and are appropriate for the industrial nature of the area. Given the existing visual character of the site, project impacts associated with the equipment change are limited and considered less than significant.

A fogging frequency curve (Figure 3.13-1) is provided for CEC staff to assess potential visible plume formation from the proposed cooling tower as a result of equipment changes at the LEC. It is anticipated that formation of visible plumes from the project would be a rare occurrence related to unusual combinations of cold and damp conditions, and that when present, the plumes would be relatively small.

The proposed changes to the plant's equipment and modified fenceline will not affect analysis of the AFC, and would not increase visual impacts beyond those addressed in the AFC. Also, no LORS will change as a result of the modification. Therefore, any potential visual impacts associated with the equipment changes would be less than significant.

3.14 Waste Management

The amount and type of wastes generated by the project will not change as a result of the equipment modification and fenceline adjustment. The proposed equipment changes and fenceline modification will not result in any potential impacts greater than those analyzed in the AFC and no LORS will change as a result of the modification. As a result, any potential waste management impacts associated with this Supplement will be less than significant.

3.15 Water Resources

As a result of the changes to the power generation equipment, the LEC will increase process water usage from 709 acre-feet per year (afy) to a maximum of 1,800 afy ; however, the quantity of process water required is within the amount to be provided by the City of Lodi per the will-serve letter included as Appendix F. Therefore, the changes to the power generation equipment and the resulting increase in water use at the LEC will not change the impact analysis as presented in the AFC. A description of process water use and wastewater generation for the revised water balance (Figure 2.1-5AR) is presented below.

3.15.1 Process Water

The LEC project will receive recycled water from the WPCF via a new pipeline and pumps to be installed in the WPCF water basin located on the northeastern side of the LEC. Incoming recycled water will be stored in the raw water tank. Recycled water from the raw water tank will be available for the fire water system. Untreated recycled water will be used for plant washwater. Water for the HSRG feedwater and condensate system will be treated by a cold lime softener clarifier and a micro-filtration system before going through the demineralization process. Once water has been treated by the demineralization system, it will be stored in a demineralized water storage tank. The tank will be sized for 200,000 gallons, which is nominally 4.76 days of plant back-up water supply. This water will be used in the heat recovery steam generator (HSRG) feedwater and condensate system for turbine water wash and combustion turbine inlet air cooling.

Figure 2.1-5AR shows the revised water balance for the LEC project. The demineralization system would include first and second pass reverse osmosis (RO) and electro-deionization. As shown in Table 3.15-1, the LEC's average daily water use would be approximately 1.84 million gallons per day (24-hour period). Maximum daily use would be 2.61 million gallons per day during the summer maximum case. A will-serve letter from the City of Lodi indicating that a sufficient amount of recycled water will be available to the project is included in Appendix F. Based on a 70 to 80 percent capacity factor (approximately 7,000 hours of operation per year), the LEC would use an average of 1,651 acre-feet (538.02 million gallons) per year of water using the average annual flow rate from Table 3.15-1.

TABLE 3.15-1
Revised LEC Flow Rates

Case (Heat Balance Case)	Daily Average Flows	
	Gallons per Minute	Million Gallons per Day[a]
Annual Average[b]	1,281	1.84
Summer Maximum[c]	1,810	2.61

[a] 24-hour operation
[b] Without evaporative cooling
[c] With evaporative cooling

3.15.2 Wastewater Collection, Treatment, Discharge, and Disposal

Wastewater from the LEC will be discharged to a new onsite Class I underground injection well to be constructed as part of the LEC project. This well will be permitted through the EPA's Underground Injection Control program, which strictly regulates the conditions under which a permit for Class I injection wells can be issued. The LEC would discharge up to a maximum of 189 gallons per minute of process wastewater to the underground injection well, which is less than the discharge amount evaluated in the AFC.

3.16 Worker Safety and Fire Protection

Implementation of worker safety plans and protocols will be the same for the proposed equipment change and fenceline modification as those described in the original AFC filing. While minor changes to the fire protection system, including the elimination of water deluge sprays for the large generator step-up transformers and the addition of water deluge spray for the existing ammonia storage tank are proposed (as described in Appendix B, Design Criteria), the modifications will not result in potential impacts greater than those analyzed in the AFC, and no LORS will change as a result of the revised fire protection system design. Therefore, any potential worker safety and fire protection impacts associated with this Supplement will be less than significant.

TABLE 5.5-1R
Use and Location of Hazardous Materials

Chemical	Use	Quantity (gallons/lbs)	Storage Location	State	Type of Storage
Anhydrous Ammonia (99% NH3) [a]	Control oxides of nitrogen (NO_x) emissions through selective catalytic reduction	10,200 gallons[b]	Onsite storage tank (shared with existing STIG plant)	Liquid	Continuously on site
Antifoam NALCO 71-D5	Cooling Tower foam control	55 gallons	Cooling tower chemical berm	Liquid	Continuously on site
Anti-scalant NALCO PC-191T	Prevent scale in reverse osmosis membranes	400 gallons	Portable Storage Tote – Water Treatment Building	Liquid	Continuously on site
Anti-scalant NALCO PC-510T[c]	Prevent scale in reverse osmosis membranes	400 gallons	Portable Storage Tote – Water Treatment Building	Liquid	Continuously on site
Biocide NALCO 3980[c]	Injection well biological control	55 gallons	Water Treatment Building	Liquid	Continuously on site
Biocide NALCO 73551 [c]	Cooling Tower bio penetrant	400 gallons	Water Treatment Building	Liquid	Continuously on site
Biocide NALCO 7330	Cooling Water Bio Control	400 gallons (totes)	Cooling Tower Chemical Feed Building	Liquid	Continuously on site
Caustic NALCO 8735[c]	Boiler makeup water pH control	25 gallons	Boiler Chemical Injection Skid	Liquid	Continuously on site
Citric Acid [c]	Non-chemical cleaning of HRSG interior piping	5,000 gallons	Pallet supported chemical storage bags in protected temporary storage location on site.	Solid Powder	Initial startup and periodically on site
Cleaning chemicals/detergents (including PC 98, PC-11, and PC 56) [c]	Periodic cleaning of combustion turbine	1,000 gallons	Portable Storage Totes/Drums –Water Treatment Building	Liquid	Continuously on site
Coagulant NALCO 8108	Cold lime softener turbidity removal	800 gallons	Cold lime softener	Liquid	Continuously on site

TABLE 5.5-1R
Use and Location of Hazardous Materials

Chemical	Use	Quantity (gallons/lbs)	Storage Location	State	Type of Storage
Corrosion Control NALCO 3DT-184	Cooling Water Corrosion Inhibitor	1000 gallons	Cooling Tower Chemical Feed Building	Liquid	Continuously on site
Diesel No. 2 [c]	Small equipment refueling	55 gallons	Onsite 55 gallon drums	Liquid	Continuously on site
Dispersant NALCO 3DT-191	Cooling Water Mineral Dispersant	1000 gallons	Cooling Tower Chemical Feed Building	Liquid	Continuously on site
Flocculant NALCO 7768	Cold lime softener turbidity removal	800 gallons	Cold lime softener	Liquid	Continuously on site
Glutamine [c]	Injection well biological control	55 gallons	Water Treatment Building	Liquid	Continuously on site
Hydraulic Oil [c]	High-pressure combustion turbine starting system, turbine control valve actuators	700 gallons	Onsite 55 gallon drums	Liquid	Continuously on site
Laboratory reagents [c]	Water/wastewater laboratory analysis	10 gallons	Laboratory chemical storage cabinets (stored in original chemical storage containers/bags)	Liquid and Granular Solid	Continuously on site
Lime	Cold lime softener hardness removal	2,000 lb	Cold lime softener	Solid	Continuously on site
Lithium Bromide [c]	Chiller Refrigerant	75 gallons	Water Treatment Building	Liquid	Continuously on site
Lubrication Oil [c]	Lubricate rotating equipment (e.g., gas turbine and steam turbine bearings)	1,500 gallons	Lubricating oil reservoirs and 55 gallon drums	Liquid	Continuously on site
Magnesium Oxide	Cold lime softener silica removal	2,000 lb	Cold lime softener	Solid	Continuously on site
Mineral Insulating Oil [c]	Transformers/switch yard	3,500 gallons	Transformer tanks and 55 gallon drums	Liquid	Continuously on site

TABLE 5.5-1R
Use and Location of Hazardous Materials

Chemical	Use	Quantity (gallons/lbs)	Storage Location	State	Type of Storage
Oxygen Scavenger (e.g., NALCO ELIMIN-OX) [c]	Oxygen scavenger for boiler water conditioning	400 gallons	Boiler Chemical Feed Building	Liquid	Continuously on site
Amine NALCO 5711	Boiler feedwater pH control	400 gallons	Boiler Chemical Feed Building	Liquid	Continuously on site
SF6	230 KV breaker insulating medium	200 lb (500 ft^3)	Switchyard	Gas	Continuously on site
Sodium Bisulfite ($NaHSO_3$) [c] NALCO PC-7408	Reduce oxidizers in reverse osmosis feed to protect the RO membranes	400 gallons	Cooling Tower Chemical Feed Building	Liquid	Continuously on site
Sodium Hydroxide (NaOH) [c]	Convert CO_2 to alkalinity for removal by reverse osmosis	10 gallons	Cooling Tower Chemical Feed Building	Liquid	Continuously on site
Sodium Hypochlorite[c]	Cooling tower biological control	1,500 gallons	Cooling Tower Chemical Feed Building	Liquid	Continuously on site
Sodium Nitrite NALCO 2536 Plus	Closed & chilled water loop corrosion inhibitor	55 gallons	Water Treatment Building	Solid	Continuously on site
Sulfur Hexaflouride [c]	230 kV breaker insulating medium	200 lb (500 ft^3)	Switchyard	Gas	Continuously on site
Sulfuric Acid (93%) [c]	Cooling tower pH control	~~3~~4,000 gallons	Cooling Tower Chemical Feed skid	Liquid	Continuously on site
NALCO BT3000	Boiler water pH control	400 gallons	Boiler Chemical Feed Building	Liquid	Continuously on site
Acetylene [c]	Welding gas	540 ft^3	Maintenance / Warehouse Building	Gas	Continuously on site
~~Hydrogen~~	~~Steam turbine generator cooling~~	~~20,000 ft^3~~	~~Pressurized bottles~~	~~Gas~~	~~Continuously on site~~

TABLE 5.5-1R
Use and Location of Hazardous Materials

Chemical	Use	Quantity (gallons/lbs)	Storage Location	State	Type of Storage
Oxygen [c]	Welding gas	540 ft^3	Maintenance / Warehouse Building	Gas	Continuously on site
Propane [c]	Torch gas	200 ft^3	Maintenance / Warehouse Building	Gas	Continuously on site
EPA Protocol Gases [c]	Calibration gases	1,000 ft^3	CEMS Enclosure	Gas	Continuously on site
Cleaning Chemicals [c]	Cleaning	Varies (less than 25 gallons liquids or 100 lbs solids for each chemical)	Admin / Control Building, Maintenance / Warehouse Building	Liquid or Solid	Continuously on site
Paint [c]	Touchup of painted surfaces	Varies (less than 25 gallons liquids or 100 lbs solids for each type)	Maintenance / Warehouse Building	Liquid	Continuously on site

[a]The LEC plant will tie into the existing anhydrous ammonia tank currently in place at the STIG plant. A new ammonia tank will not be built for the LEC facility.

[b]Existing ammonia tank capacity is 12,000 gallons; however, the tank is only filled to 85% of its capacity, or 10,200 gallons.

[c]Chemical currently in use at STIG to be used by both STIG and LEC facilities.

TABLE 5.5-2R
Chemical Inventory, Description of Hazardous Materials Stored Onsite, and Reportable Quantities

Trade Name	Chemical Name	CAS Number	Maximum Quantity Onsite	CERCLA SARA RQ[a]	RQ of Material as Used Onsite[b]	EHS TPQ[c]	Regulated Substance TQ[d]	Prop 65
Anhydrous Ammonia	Anhydrous Ammonia	7664-41-7 (NH_3)	10,200 [g] gallons	100 lb	100 lb	500 lb	10,000 lb	No
Antifoam NALCO 71-D5	Straight Run Middle Distillate (60-100%)	64741-44-2	55 gallons	[e]	[e]	[e]	[e]	No
	Polypropylene Glycol (5-10%)	25322-69-4		[e]	[e]	[e]	[e]	No
	Aliphatic hydrocarbon (5-10%)	Proprietary		[e]	[e]	[e]	[e]	No
	Paraffin Wax (1-5%)	8002-74-2		[e]	[e]	[e]	[e]	No
	Oxyalkylate (1-5%)	Proprietary		[e]	[e]	[e]	[e]	No
Anti-scalant NALCO PC191T	Anti-scalant	Various	400 gallons	[e]	[e]	[e]	[e]	No
Anti-scalant NALCO PC510T	None	None	400 gallons	[e]	[e]	[e]	[e]	No
Biocide NALCO 3980	5-Chloro-2-Methyl-4-Isothiazolin-3-one (1-5%)	26172-55-4	55 gallons	[e]	[e]	[e]	[e]	No
	2-Methyl-4-Isothiazolin-3-one (0.1-1%)	2682-20-4		[e]	[e]	[e]	[e]	No
	Magnesium Nitrate (1-5%)	10377-60-3		[e]	[e]	[e]	[e]	No
Biocide NALCO 73551	None	None	400 gallons	[e]	[e]	[e]	[e]	No
Biocide NALCO 7330	5-Chloro-2-Methyl-4-Isothiazolin-3-one (1-5%)	26172-55-4	400 gallons	[e]	[e]	[e]	[e]	No No
	2-Methyl-4-Isothiazolin-3-one (0.1-1%)	2682-20-4		[e]	[e]	[e]	[e]	No
	Magnesium Nitrate (1-5%)	10377-60-3		[e]	[e]	[e]	[e]	
Caustic NALCO 8735	Sodium Hydroxide (30-60%)	1310-73-2	25 gallons	1,000 lb	1,667 lb	[e]	[e]	No
	Potassium Hydroxide (10-30%)	1310-58-3		1,000 lb	3,333 lb	[e]	[e]	No

TABLE 5.5-2R
Chemical Inventory, Description of Hazardous Materials Stored Onsite, and Reportable Quantities

Trade Name	Chemical Name	CAS Number	Maximum Quantity Onsite	CERCLA SARA RQ[a]	RQ of Material as Used Onsite[b]	EHS TPQ[c]	Regulated Substance TQ[d]	Prop 65
Citric Acid	Citric Acid	77-92-9	5,000 gallons	[e]	[e]	[e]	[e]	No
Cleaning chemicals/detergents	Various	None	1,000 gallons	[e]	[e]	[e]	[e]	No
Coagulant NALCO 8108	None	None	800 gallons	[e]	[e]	[e]	[e]	No
Corrosion Control NALCO 3DT-184	Phosphoric Acid (30-60%)	7664-38-2	1,000 gallons	5,,000 lb	8333 lb	[e]	[e]	No
Diesel No. 2	Diesel No. 2	68476-34-6	55 gallons	[e]	[e]	[e]	[e]	No
Dispersant NALCO 3DT-191	None	None	1,000 gallons	[e]	[e]	[e]	[e]	No
Flocculant NALCO 7768	None	None	800 gallons	[e]	[e]	[e]	[e]	No
Glutamine	Glutamine	56-85-9	55 gallons	[e]	[e]	[e]	[e]	No
Hydraulic Oil	Oil	None	700 gallons	42 gal [f]	42 gal [f]	[e]	[e]	No
Laboratory reagents	Various	Various	10 gallons	[e]	[e]	[e]	[e]	No
Lime	Calcium Hydroxide	1305-62-0	2,000 pounds	[e]	[e]	[e]	[e]	No
Lithium Bromide	Lithium Bromide	7550-35-8	75 gallons	[e]	[e]	[e]	[e]	No
Lubrication Oil	Oil	None	1,500 gallons	42 gal [f]	42 gal [f]	[e]	[e]	No
Magnesium Oxide	Magnesium Oxide	1309-48-4	2,000 pounds	[e]	[e]	[e]	[e]	No
Mineral Insulating Oil	Oil	8012-95-1	3,500 gallons	42 gal [f]	42 gal [f]	[e]	[e]	No
Oxygen Scavenger (e.g., NALCO ELIMIN-OX)	Oxygen Scavenger	None	400 gallons	[e]	[e]	[e]	[e]	No

TABLE 5.5-2R
Chemical Inventory, Description of Hazardous Materials Stored Onsite, and Reportable Quantities

Trade Name	Chemical Name	CAS Number	Maximum Quantity Onsite	CERCLA SARA RQ[a]	RQ of Material as Used Onsite[b]	EHS TPQ[c]	Regulated Substance TQ[d]	Prop 65
Amine NALCO 5711	Ammonia (10-30%)	7664-41-7	400 gallons	100 lb	333 lb	500 lb	20,000 lb	No
	Monoethanolamine (5-10%)	141-43-5		e	e	e	e	No
Sodium Bisulfite ($NaHSO_3$) NALCO PC-7408	Sodium Bisulfite (30-60%)	7631-90-5	400 gallons	5,000 lb	8,333 lb	e	e	No
Sodium Hydroxide (NaOH)	Sodium Hydroxide	1310-73-2	10 gallons	1,000 lb	1,000 lb	e	e	No
Sodium Hypochlorite	Sodium Hypochlorite	7681-52-9	1,500 gallons	100 lb	100 lb	e	e	No
Sodium Nitrite NALCO 2536 Plus	Sodium Nitrite (1-5%)	7632-00-0	30 gallons	100 lb	100 lb	e	e	No
	Sodium Metasilicate (1-5%)	6834-92-0		e	e	e	e	No
	Sodium Tetraborate (1-5%)	1330-43-4		e	e	e	e	No
	Sodium Nitrate (1-5%)	7631-99-4		e	e	e	e	No
	Sodium Mercaptobenzothiazole (0-0.1%)	2492-26-4		e	e	e	e	No
Sulfur Hexafluoride	Sulfur Hexafluoride	2551-62-4	200 lbs	e	e	e	e	No
Sulfuric Acid (93%)	Sulfuric Acid	7664-93-9	~~3~~4,000 gallons	1,000 lb	1,075 lb	1,000 lb	1,000 lb	Yes
NALCO BT-3000	Sodium Hydroxide (1-5%)	1310-73-2	400 gallons	1,000 lb	20,000 lb	e	e	No
	Sodium Tripolyphosphate (1-5%)	7758-29-4		e	e	e	e	No
Acetylene	Acetylene	47-86-2	540 ft^3	e	e	e	e	No
~~Hydrogen~~	~~Hydrogen~~	~~1333-74-0~~	~~20,000 ft^3~~	~~e~~	~~e~~	~~e~~	~~10,000 lb (federal)~~	~~No~~

TABLE 5.5-2R
Chemical Inventory, Description of Hazardous Materials Stored Onsite, and Reportable Quantities

Trade Name	Chemical Name	CAS Number	Maximum Quantity Onsite	CERCLA SARA RQ[a]	RQ of Material as Used Onsite[b]	EHS TPQ[c]	Regulated Substance TQ[d]	Prop 65
Oxygen	Oxygen	7782-44-7	540 ft^3	[e]	[e]	[e]	[e]	No
Propane	Propane	74-98-6	200 ft^3	[e]	[e]	[e]	[e]	No
EPA Protocol Gases	Various	Various	1,000 ft^3	[e]	[e]	[e]	[e]	No
Cleaning Chemicals	Various	Various	Varies (less than 25 gallons liquids or 100 lbs solids for each chemical)	[e]	[e]	[e]	[e]	No
Paint	Various	Various	Varies (less than 25 gallons liquids or 100 lbs solids for each type)	[e]	[e]	[e]	[e]	No

[a] RQ for a pure chemical, per the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) Superfund Amendments and Reauthorization Act (SARA) (Ref. 40 Code of Federal Regulations [CFR] 302, Table 302.4). Release equal to or greater than RQ must be reported. Under California law, any amount that has a realistic potential to adversely affect the environment or human health or safety must be reported.

[b] RQ for materials as used onsite. Since some of the hazardous materials are mixtures that contain only a percentage of an RQ, the RQ of the mixture can be different than for a pure chemical. For example, if a material only contains 10% of a reportable chemical and the RQ is 100 lb., the RQ for that material would be (100 lb.)/(10%) = 1,000 lb.

[c] Extremely Hazardous Substance (EHS) TPQ (Ref. 40 CFR Part 355, Appendix A). If quantities of extremely hazardous materials equal to or greater than the TPQ are handled or stored, they must be registered with the local Administering Agency.

[d] TQ is from 19 California Code of Regulations (CCR) 2770.5 (state) or 40 CFR 68.130 (federal)

[e] No reporting requirement. Chemical has no listed threshold under this requirement.

[f] State RQ for oil spills that will reach California state waters [Ref. CA Water Code Section 13272(f)]

[g] Existing Ammonia tank capacity is 12,000 gallons; however, the tank is only filled to 85% of its capacity, or 10,200 gallons.

TABLE 5.5-3R
Toxicity, Reactivity, and Flammability of Hazardous Substances Stored Onsite

Hazardous Materials	Physical Description	Health Hazard	Reactive & Incompatibles	Flammability*
Anhydrous Ammonia (99% NH_3)	Colorless gas with pungent odor	*Corrosive*: Irritation to permanent damage from inhalation, ingestion, and skin contact.	Acids, halogens (e.g., chlorine), strong oxidizers, salts of silver and zinc.	Combustible, but difficult to burn
Antifoam NALCO 71-D5	Liquid, straw-colored	Causes irritation to skin and eyes	None known	Slightly flammable
Anti-scalant NALCO PC-510T	Amber liquid	May cause slight irritation to the skin and moderate irritation to the eyes	None	Non flammable
Anti-scalant NALCO PC-191T	Yellow liquid	May cause irritation with prolonged contact.	Strong oxidizing agents, strong acids	Slightly flammable
Biocide NALCO 3980	Light green/Light yellow Liquid	Corrosive: Causes irreversible eye damage or skin burns. Harmful if inhaled, swallowed or absorbed through the skin.	Strong oxidizers may generate heat, fires, explosions and/or toxic vapors	Non-flammable
Biocide NALCO 73551	Colorless Liquid	May cause irritation with prolonged contact	Freezing temperatures	Slightly flammable
Biocide NALCO 7330	Light green/Light Yellow Liquid	Corrosive: Causes irreversible eye damage or skin burns. Harmful if inhaled, swallowed or absorbed through skin.	Strong oxidizers may generate heat, fires, explosions and/or toxic vapors	Non-flammable
Caustic NALCO 8735	Colorless Liquid, no odor	Corrosive: Causes eye and skin burns. May cause severe respiratory tract irritation with possible burns. May cause severe digestive tract irritation with possible burns.	Aluminum, tin, zinc, and zinc alloys and strong acids	Not flammable
Citric Acid	Odorless, white granules	Causes irritation to the skin, gastrointestinal tract, and respiratory tract	Metal nitrates (potentially explosive reaction), alkali carbonates and bicarbonates, potassium tartrate. Will corrode copper, zinc, aluminum and their alloys.	Slightly flammable
Cleaning chemicals/detergents	Liquid	Refer to individual chemical labels	Refer to individual chemical labels	Refer to individual chemical labels

TABLE 5.5-3R
Toxicity, Reactivity, and Flammability of Hazardous Substances Stored Onsite

Hazardous Materials	Physical Description	Health Hazard	Reactive & Incompatibles	Flammability*
PC-56	Light Green/Light Yellow Liquid	Corrosive: Causes irreversible eye damage or skin burns. Harmful if inhaled, swallowed or absorbed through skin.	Strong oxidizers	Non-flammable
PC-11	Clear/Colorless Amber Liquid	Corrosive: Causes irreversible eye damage or skin burns. Harmful if inhaled, swallowed or absorbed through skin.	Strong alkalies may generate heat, splattering or boiling and toxic vapors. Oxidizing agents. Aluminum	Slightly flammable
PC-98	Opaque Liquid	May cause irritation with prolonged contact	Acids may generate heat, splattering or boiling and toxic vapors.	Non-flammable
Coagulant NALCO 8108	Clear, light yellow liquid	May cause irritation with prolonged contact. Toxic to aquatic organisms	Strong oxidizers	Slightly flammable
Corrosion Control NALCO 3DT-184	Liquid, Clear Amber Brown	Corrosive: May cause tissue damage	None	Non-flammable
Diesel No. 2	Oily, light liquid	May be carcinogenic	Sodium hypochlorite	Flammable
Dispersant NALCO 3D-191	Clear orange liquid	May cause irritation with prolonged contact	Strong oxidizers may generate heat, fires, explosions and/or toxic vapors	Slightly flammable
Flocculant NALCO 7768	Off-white emulsion	May cause irritation with prolonged contact. Toxic to aquatic organisms	Strong oxidizers may generate heat, fires, explosions and/or toxic vapors. Addition of water results in gelling.	Slightly flammable
Glutamine	Liquid	Causes irritation to skin and eyes	None known	Non flammable
Hydraulic Oil	Oily, dark liquid	Hazardous if ingested	Sodium hypochlorite. Oxidizers	Combustible
Laboratory reagents	Liquid and solid	Refer to individual chemical labels	Refer to individual chemical labels	Refer to individual chemical labels
Lithium bromide	Liquid	Hazardous if ingested, Causes irritation to skin and eyes	None known	Non flammable
Lime	White dry powder	Irritation of eyes, respiratory or red “sunburn like” skin	Water and acids	Non-flammable

TABLE 5.5-3R
Toxicity, Reactivity, and Flammability of Hazardous Substances Stored Onsite

Hazardous Materials	Physical Description	Health Hazard	Reactive & Incompatibles	Flammability*
Lubrication Oil	Oily, dark liquid	Hazardous if ingested	Sodium hypochlorite. Oxidizers	Flammable
Magnesium Oxide	Bulky white powder	Magnesium oxide is slowly absorbed. Ingestion may cause rapid bowel evacuation. Inhalation can cause a flu-like illness (metal fume fever). This 24- to 48-hour illness is characterized by chills, fever, aching muscles, dryness in the mouth and throat and headache.	Acids, interhalogens, phosphorus pentachloride, and chlorine trifluoride.	Non-flammable
Mineral Insulating Oil	Oily, clear liquid	Minor health hazard	Sodium hypochlorite. Oxidizers	Can be combustible, depending on manufacturer
Oxygen Scavenger NALCO ELIMIN-OX	Light yellow liquid with sulfurous odor	May cause asthma like attack if ingested. Can cause mild irritation. Causes asthmatic signs and symptoms in hyper-reactive individuals.	None	Not flammable
Amine NALCO 5711	Clear, pale yellow liquid with phenolic-amine odor	Harmful if swallowed. Causes irreversible eye damage.	Hazardous polymerization will not occur	Not flammable
Sodium Bisulfite NALCO PC-7408	Yellow liquid	Corrosive: Irritation to eyes, skin, and lungs; may be harmful if digested	Strong acids and strong oxidizing agents	Non flammable
Sodium Hydroxide	Solid, white, and odorless	Causes eye and skin burns. Hygroscopic. May cause severe respiratory tract irritation with possible burns. May cause severe digestive tract irritation with possible burns.	Incompatible with acids, water, flammable liquids, organic halogens, metals, aluminum, zinc, tin, leather, wool, and nitromethane.	Not flammable
Sodium Hypochlorite	Colorless liquid with strong odor	Harmful by ingestion, inhalation and through skin contact	Incompatible with strong acids, amines, ammonia, ammonium salts, reducing agents, metals, aziridine, methanol, formic acid, phenylacetonitrile.	Not flammable

TABLE 5.5-3R
Toxicity, Reactivity, and Flammability of Hazardous Substances Stored Onsite

Hazardous Materials	Physical Description	Health Hazard	Reactive & Incompatibles	Flammability*
Sodium Nitrite NALCO 2536 Plus	White to slightly yellowish. Solid (powdered solid), odorless	Very hazardous in case of eye contact (irritant), of ingestion, of inhalation. Hazardous in case of skin contact (irritant). Slightly hazardous in case of skin contact (permeator). Prolonged exposure may result in skin burns and ulcerations. Over-exposure by inhalation may cause respiratory irritation. Severe over-exposure can result in death. Inflammation of the eye is characterized by redness, watering, and itching.	Highly reactive with combustible materials, organic materials. Reactive with reducing agents, metals, acids. Slightly reactive to reactive with moisture.	Not flammable
Sulfur Hexaflouride	Colorless gas with no odor	Hazardous if inhaled	Disilane	Non flammable
Sulfuric Acid (93%)	Oily, colorless to slightly yellow, clear to turbid liquid. Odorless.	Causes severe skin burns. Causes severe eye burns. Causes burns of the mouth, throat, and stomach.	Nitro compounds, carbides, dienes, alcohols (when heated): causes explosions. Oxidizing agents, such as chlorates and permanganates: causes fires and possible explosions. Allyl compounds and aldehydes: undergoes polymerization, possibly violent. Alkalies, amines, water, hydrated salts, carboxylic acid anhydrides, nitriles, olefinic organics, glycols, aqueous acids: causes strong exothermic reactions.	Not flammable
NALCO BT-3000	Light Yellow Liquid	Corrosive. Will cause eye burns and permanent tissue damage	Strong acids	Not flammable

TABLE 5.5-3R
Toxicity, Reactivity, and Flammability of Hazardous Substances Stored Onsite

Hazardous Materials	Physical Description	Health Hazard	Reactive & Incompatibles	Flammability*
Acetylene	Colorless gas	Asphyxiant gas	Oxygen and other oxidizers including all halogens and halogen compounds. Forms explosive acetylide compounds with copper, mercury, silver, brasses containing >66 percent copper and brazing materials containing silver or copper.	Flammable
~~Hydrogen~~	~~Colorless, odorless, flammable gas or a colorless, odorless, cryogenic liquid.~~	~~Asphyxiation, by displacement of oxygen.~~	~~Strong oxidizers (e.g., chlorine, bromine, oxygen, oxygen difluoride, and nitrogen trifluoride). Oxygen/Hydrogen mixtures can explode on contact with a catalyst such as platinum.~~	~~Flammable~~
Oxygen	Colorless, odorless, tasteless gas	Therapeutic overdoses can cause convulsions. Liquid oxygen is an irritant to skin.	Hydrocarbons, organic materials	Oxidizing agent; actively supports combustion
Propane	Propane gas (odorant added to provide odor)	Asphyxiant gas. Causes frostbite to area of contact.	Strong oxidizing agents and high heat	Flammable
EPA Protocol Gases	Gas	Refer to individual chemical labels	Refer to individual chemical labels	Refer to individual chemical labels
Cleaning Chemicals	Liquid	Refer to individual chemical labels	Refer to individual chemical labels	Refer to individual chemical labels
Paint	Various colored liquid	Refer to individual container labels	Refer to individual container labels	Refer to individual container labels

Notes:

Data were obtained from Material Safety Data Sheets (MSDSs) and Lewis, 1991.

Per Department of Transportation regulations, under 49 CFR 173: “Flammable” liquids have a flash point less than or equal to 141 degrees Fahrenheit; “Combustible” liquids have a flash point greater than 141° F.

Figures

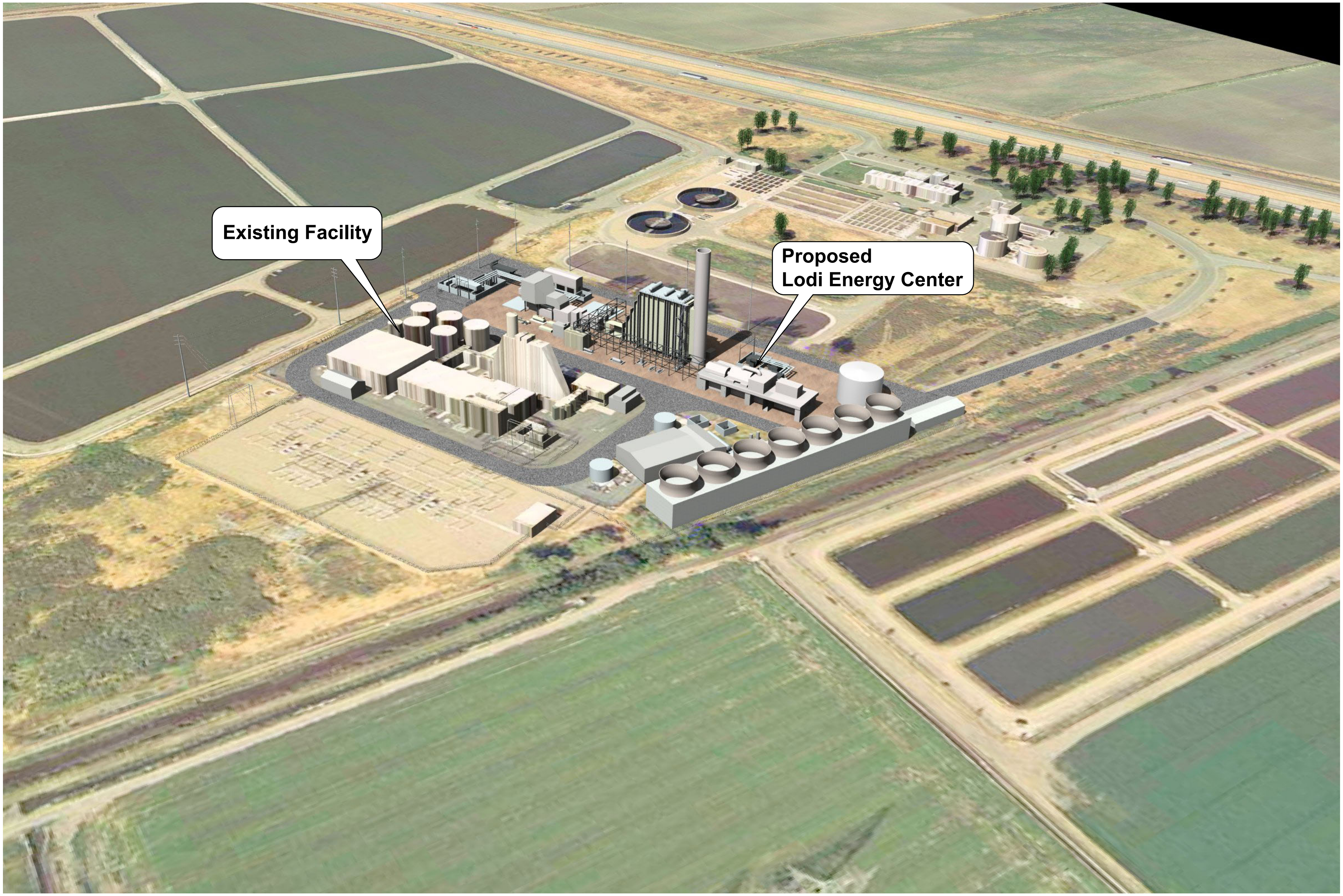
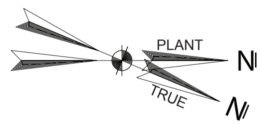


FIGURE 1.1-1R
ARCHITECTURAL RENDERING
LODI ENERGY CENTER
LODI, CALIFORNIA



PLANT SITE DESCRIPTION

1. COMBUSTION TURBINE/GENERATOR
2. HRSG
3. STEAM TURBINE/GENERATOR
4. COOLING TOWER
5. GSUT
6. GAS METERING AREA
7. WATER TREATEMENT BUILDING
8. COOLING TOWER CHEM TOTES
9. DEMINERALIZED WATER TANK
10. CEMS BUILDING
11. STIG PLANT COOLING TOWER (TEMPORARY)
12. ELECT SWGR ROOM
13. OIL/WATER SEPARATOR
14. BOILER FEED WATER PUMPS
15. BOILER BLOWDOWN TANK
16. COOLING TOWER CHEM FEED TANK
17. GEN. CIRCUIT BREAKER
18. RAW WATER TANK
19. STG / HRSG PDC
20. CTG PDC
21. STEAM TURBINE SOUND ENCLOSURE
22. STACK
23. 4160V UNIT AUX. TRANSFORMER
24. EXCITATION TRANSFORMER
25. COOLING WATER PUMP STRUCTURE
26. U/G CIRCULATING WATER PIPING
27. EXISTING INJECTION WELL
28. NCPA WAREHOUSE EXTENSION (NEW)
29. POTABLE WATER WELL
30. 480V SUS TRANSFORMER
31. REPLACEMENT WELL (FUTURE)
32. INJECTION WELL HEAD
33. FUEL GAS PERFORMANCE HEATER
34. INJECTION WATER STORAGE TANK
35. AMMONIA SKID
36. AUXILIARY BOILER
37. AMMONIA STORAGE TANK (EXISTING)
38. FIRE PUMP (EXISTING)
39. HYDRAULIC SKID
40. CONTROL ROOM (EXISTING)
41. ROTOR AIR COOLER
42. MAIN ENTRANCE
43. SECONDARY ENTRANCE
44. NH3 FORWARDING SKID
45. STIG PLANT COOLING WATER PUMPS (TEMPORARY)
46. FIREWATER TANK (EXISTING)
47. FIREWATER TANK (EXISTING)
48. DEMIN. WATER TANK (EXISTING)
49. R.O. WATER STORAGE TANK (EXISTING)
50. R.O. WATER STORAGE TANK (EXIST.)
51. WASTE TANK (EXISTING)
52. GAS COMPRESSORS
53. RELOCATED GAS COMP.
54. GAS COMPRESSOR FILTER
55. TRANSMISSION TOWER
56. GAS COMP. AFTERCOOLER
57. FUEL GAS FILTER/SEPARATOR
58. HYDRAULIC SUPPLY SKID
59. CONDENSATE EXTRACTION PUMPS
60. LUBE OIL SKID
61. GLAND STEAM SKID/CONDENSER
62. VACUUM PUMPS
63. SEE/SFC PACKAGE & TRANSFORMERS
64. VT & SURGE CUBICLE
65. ELECTRICAL PACKAGE
66. DEW POINT HEATER
67. G. T. LUBE OIL SKID
68. DEMIN WATER TRANS. PUMPS
69. S. T. DRAIN TANK
70.
71.
72. HEAT EXCHANGER
73. GLAND STEAM CONDENSER

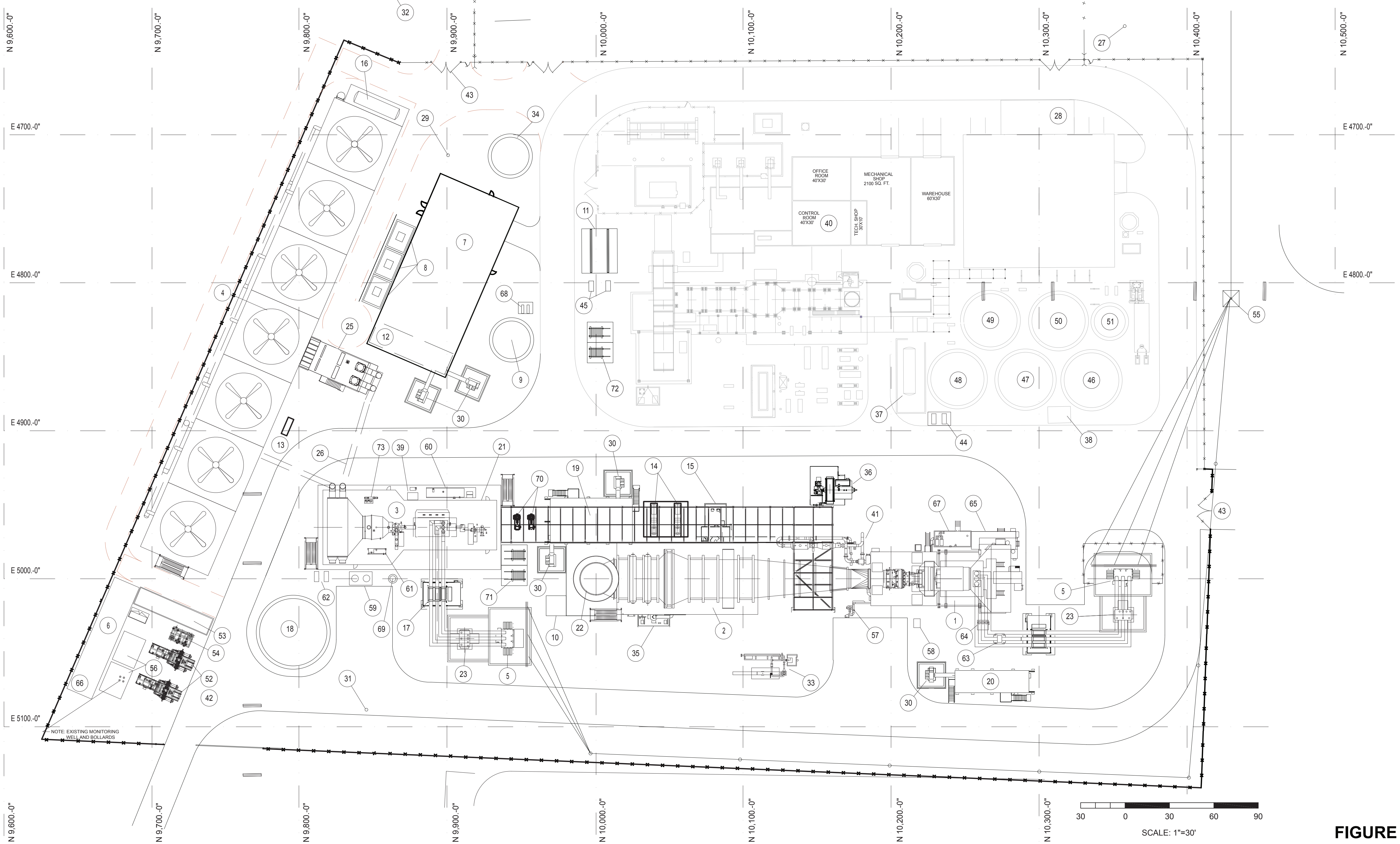
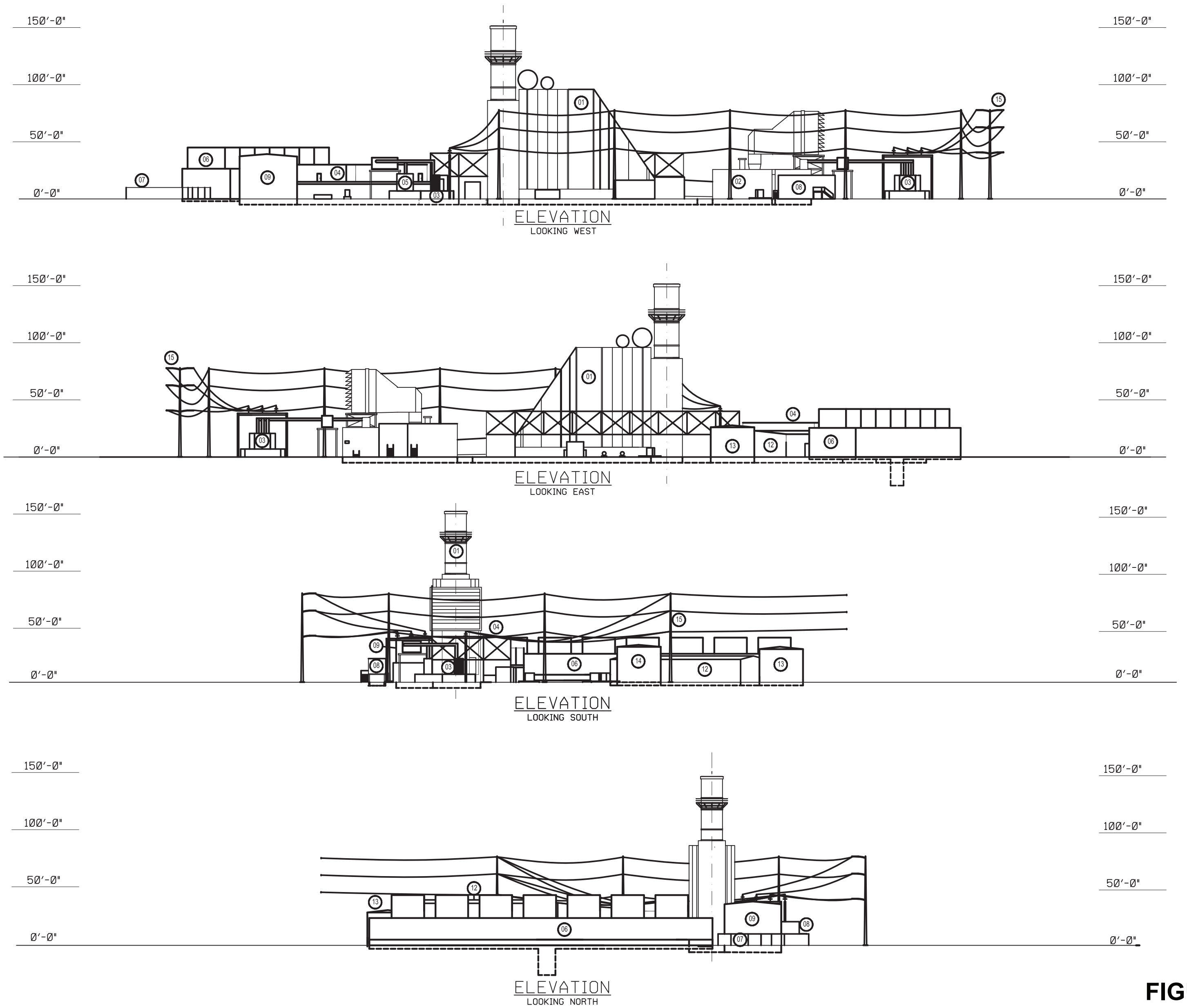


FIGURE 2.1-1R
GENERAL ARRANGEMENT
LODI ENERGY CENTER - SUPPLEMENT D
LODI, CALIFORNIA

Source: Worley Parsons LTD, Drawing LODI-0-DW-111-007-002A, 6-4-09



LEGEND:

01- HRSG
02- COMBUSTION TURBINE GENERATOR
03- GENERATOR STEP-UP TRANSFORMER
04- STEAM TURBINE GENERATOR
05- UNIT AUX TRANSFORMER
06- COOLING TOWER
07- GAS COMPRESSORS
08- PDC
09- RAW WATER STORAGE TANK
10- NOT USED
11- NOT USED
12- WATER TREATMENT BUILDING
13- WASTE WATER STORAGE TANK
14- DEMINERALIZED WATER TANK
15- TRANSMISSION TOWER

NOTES:

ELEVATION DRAWINGS ARE REFERENCING PLANT NORTH

40 0 40 80 120

SCALE: 1" = 40'

Source: Worley Parsons LTD, LODI-0-SK-111-002-101D, 07-24-09

FIGURE 2.1-2R
ELEVATIONS
LODI ENERGY CENTER - SUPPLEMENT D
LODI, CALIFORNIA

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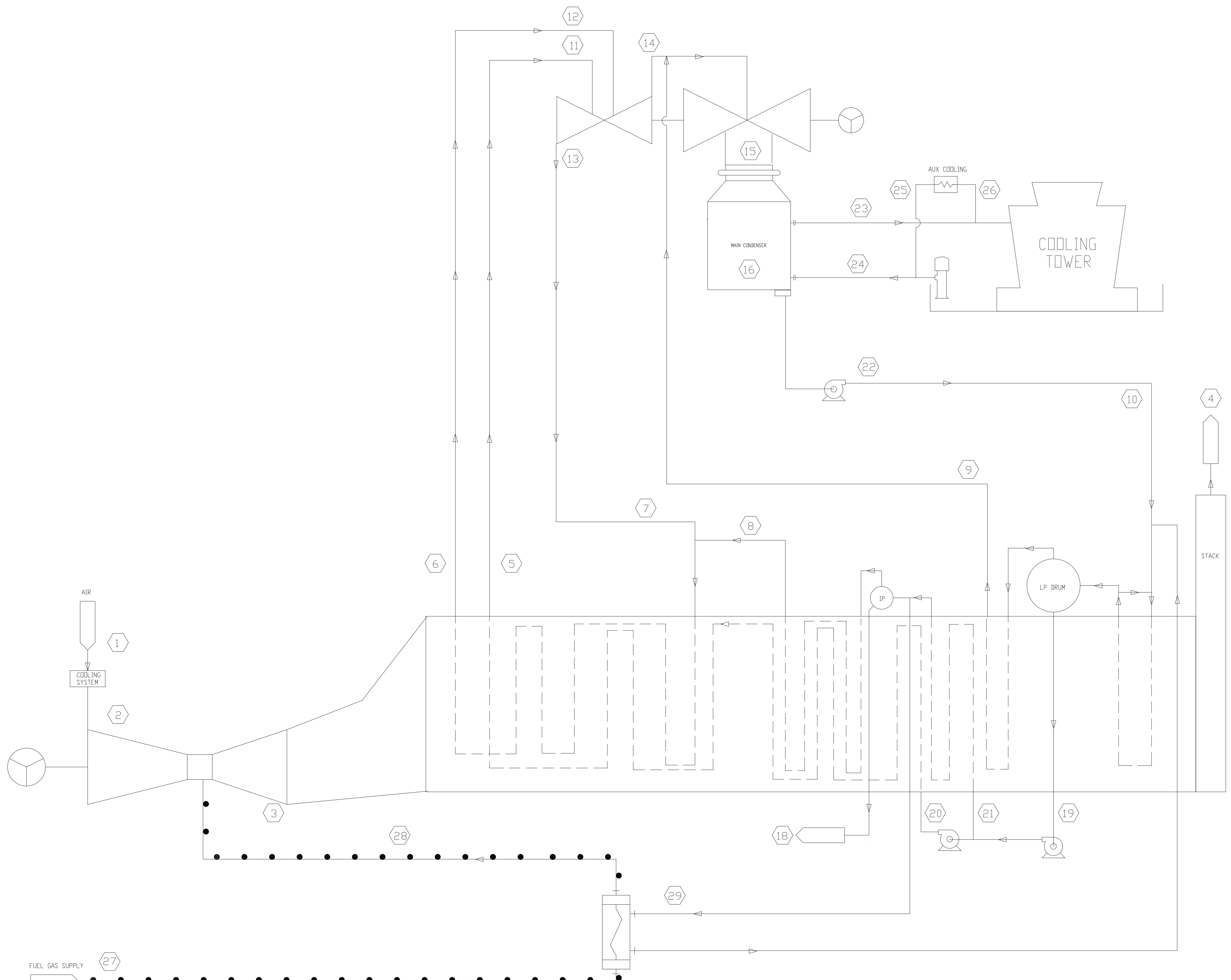
CH2MHILL



LEGEND

	WATER OR STEAM
	FUEL
F	TEMPERATURE, ^F
P	PRESSURE, PSIA
W	MASS FLOW, LBM/HR
H	ENTHALPY, BTU/LBM
KWe	POWER, KILOWATTS ELECTRICAL
GPM	GALLONS PER MINUTE

NOTE

1. FUEL HEATING VALUE = 20,254 BTU/LB LHV

FIGURE 2.1-4AR
HEAT BALANCE DIAGRAM
LODI ENERGY CENTER - SUPPLEMENT D
LODI, CALIFORNIA

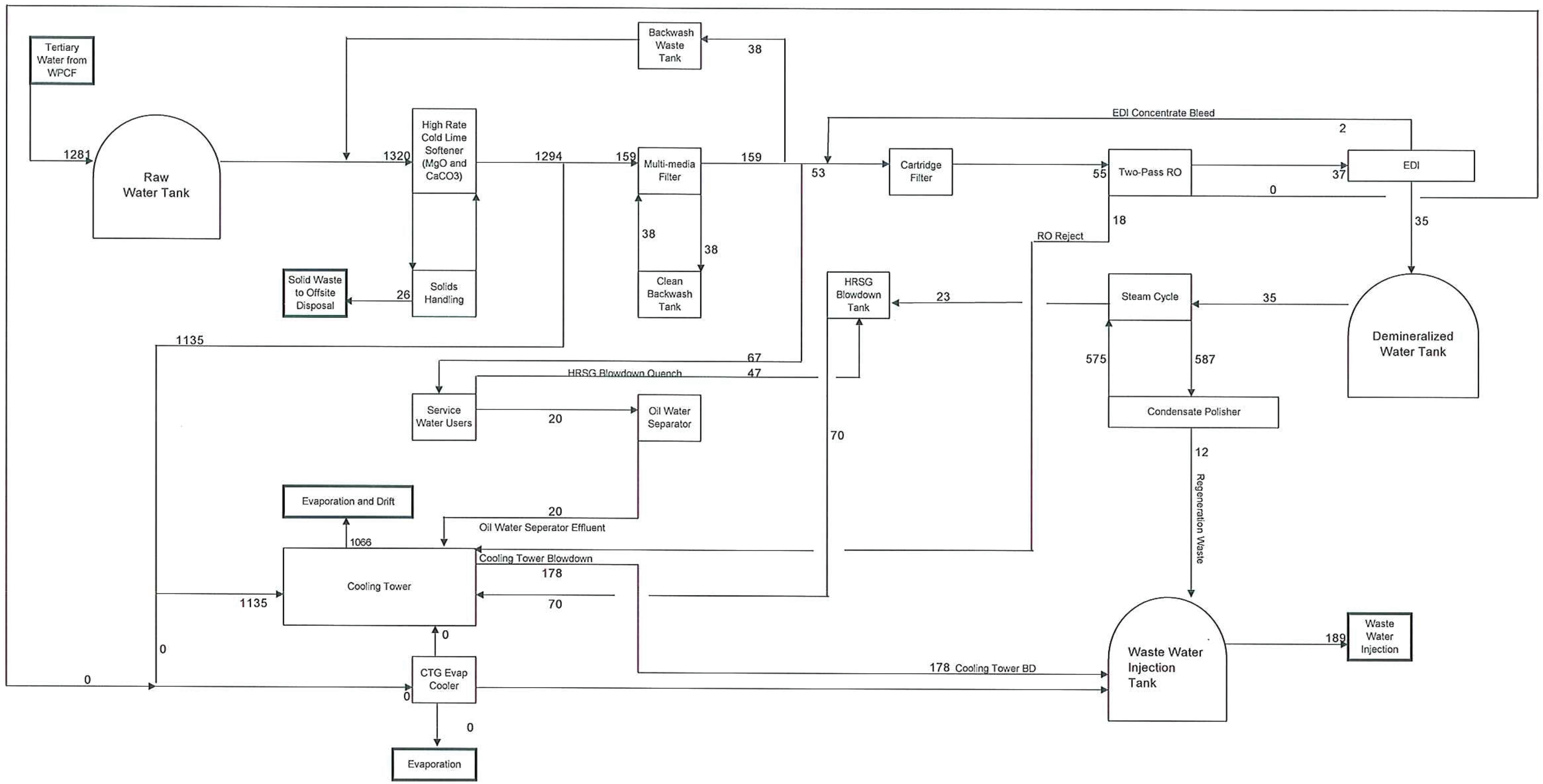
Source: Worley Parsons, LODI-1-HT-021-0001 RB, 6-4-09

Case		Plant Net Power	Net Cycle LHV Heat Rate	Net Cycle HHV Heat Rate	Gross Gas Turbine Power	ST Generator Output	Steam Cycle BOP Losses	Total LHV Fuel Cons.	Total HHV Fuel Cons.
		MW	BTU/kW-hr	BTU/kW-hr	MW	kW	kW	MMBTU/hr	MMBTU/hr
Annual Avg		298.5	6,096	6,761	202.1	102,865	6,500	1,820	2,018
Summer Typ	Evap ON	283.7	6,108	6,774	188.9	101,309	6,500	1,733	1,922
Summer Max	Evap ON	278.7	6,118	6,785	184.5	100,654	6,500	1,705	1,891
Winter Typ		312.7	6,115	6,782	215.6	103,610	6,500	1,912	2,121

Stream ID	Case	UOM	Annual Avg	Summer Typ Evap ON	Summer Max Evap ON	Winter Typ
1	**Ambient Conditions**					
	Dry Bulb Temperature	F	61.2	94.0	107.7	32.6
	Wet Bulb Temperature	F	54.8	68.9	72.9	29.7
	Relative Humidity		0.668	0.275	0.182	0.740
	Pressure	psia	14.7	14.7	14.7	14.7
2	**GT Compressor Inlet**					
	Air Flow	lb/hr	3,925,576	3,752,863	3,694,609	4,106,534
	Air Temperature	F	61.2	72.6	78.0	32.6
3	**CTG 1 Exhaust**					
	Flow	lb/hr	4,015,410	3,838,424	3,778,779	4,200,954
	Temperature	F	1,078.0	1,094.0	1,100.0	1,060.0
4	**HRSG Stack Exit**					
	Flow	lb/hr	4,015,410	3,838,424	3,778,779	4,200,954
	Temperature	F	183.2	184.3	184.5	181.5
	Pressure	psia	14.5	14.6	14.6	14.5
	Enthalpy	BTU/lb	31.0	31.5	31.6	30.5
5	**HP Steam From HRSG**					
	Flow	lb/hr	454,742	448,942	447,006	459,296
	Temperature	F	1,012.2	1,024.9	1,029.6	998.1
	Pressure	psia	1,807.5	1,795.3	1,791.4	1,813.5
	Enthalpy	BTU/lb	1,487.9	1,496.0	1,499.1	1,479.0
6	**HRH Steam From HRSG**					
	Flow	lb/hr	532,813	522,693	519,243	542,148
	Temperature	F	1,005.8	1,018.3	1,023.0	991.7
	Pressure	psia	401.1	395.3	393.4	406.0
	Enthalpy	BTU/lb	1,526.3	1,533.1	1,535.7	1,518.6
7	**CRH Steam To HRSG**					
	Flow	lb/hr	454,742	448,942	447,006	459,296
	Temperature	F	647.5	656.4	659.8	637.7
	Pressure	psia	418.8	412.8	410.7	423.9
	Enthalpy	BTU/lb	1,333.2	1,338.6	1,340.6	1,327.3
8	**IP Steam From HRSG**					
	Flow	lb/hr	78,071	73,751	72,236	82,852
	Temperature	F	613.8	613.5	613.5	613.5
	Pressure	psia	418.8	412.8	410.8	423.9
	Enthalpy	BTU/lb	1,313.9	1,314.3	1,314.4	1,313.4
9	**LP Steam From HRSG**					
	Flow	lb/hr	74,088	70,588	69,309	77,726
	Temperature	F	512.2	509.4	508.5	515.0
	Pressure	psia	66.6	65.0	64.5	68.1
	Enthalpy	BTU/lb	1,288.6	1,287.4	1,287.0	1,289.8
10	**Condensate To HRSG**					
	Flow	lb/hr	661,611	645,469	639,916	677,323
	Temperature	F	93.8	101.4	103.8	83.8
	Pressure	psia	87.8	84.3	83.1	91.8
	Enthalpy	BTU/lb	62.1	69.6	72.0	52.1
11	**HP Steam To STG**					
	Flow	lb/hr	454,742	448,942	447,006	459,296
	Temperature	F	1,009.2	1,022.0	1,026.8	995.0
	Pressure	psia	1,748.2	1,736.4	1,732.6	1,754.0
	Enthalpy	BTU/lb	1,487.9	1,496.0	1,499.1	1,479.0
12	**HRH Steam To STG**					
	Flow	lb/hr	532,814	522,693	519,243	542,148
	Temperature	F	1,004.3	1,016.9	1,021.6	990.2
	Pressure	psia	374.6	369.2	367.4	379.2
	Enthalpy	BTU/lb	1,526.3	1,533.1	1,535.7	1,518.6
13	**CRH Steam From STG**					
	Flow	lb/hr	454,742	448,942	447,006	459,296
	Temperature	F	648.2	657.0	660.4	638.4
	Pressure	psia	424.0	418.0	415.9	429.0
	Enthalpy	BTU/lb	1,333.2	1,338.6	1,340.6	1,327.3
14	**IP STG Exhaust**					
	Flow	lb/hr	74,088	70,588	69,309	77,726
	Temperature	F	510.9	508.3	507.4	513.7
	Pressure	psia	59.9	58.8	58.4	60.9
	Enthalpy	BTU/lb	1,288.6	1,287.4	1,287.0	1,289.8
15	**STG Exhaust**					
	Flow	lb/hr	606,902	593,281	588,553	619,874
	Temperature	F	90.6	99.0	101.6	79.6
	Pressure	psia	0.7	0.9	1.0	0.5
	Enthalpy	BTU/lb	1,023.1	1,028.5	1,031.3	1,020.3
16	**Condenser Hotwell**					
	Flow	lb/hr	606,902	593,281	588,553	619,874
	Temperature	F	90.6	99.0	101.6	79.6
	Pressure	psia	0.7	0.9	1.0	0.5
	Enthalpy	BTU/lb	58.6	67.0	69.6	47.6
17	**HP Blowdown**					
	Flow	lb/hr	0	0	0	0
	Temperature	F	-	-	-	-
	Pressure	psia	-	-	-	-
	Enthalpy	BTU/lb	-	-	-	-
18	**IP Blowdown**					
	Flow	lb/hr	1,593	1,505	1,474	1,691
	Temperature	F	458.3	456.1	455.4	460.3
	Pressure	psia	459.0	449.4	446.1	468.3
	Enthalpy	BTU/lb	439.6	437.2	436.3	441.9
19	**BFP Suction**					
	Flow	lb/hr	587,528	574,880	570,604	599,598
	Temperature	F	302.8	301.0	300.4	304.5
	Pressure	psia	69.9	68.0	67.4	71.6
	Enthalpy	BTU/lb	272.6	270.8	270.1	274.3
20	**HP Feedwater**					
	Flow	lb/hr	454,742	448,942	447,006	459,296
	Temperature	F	307.0	305.2	304.6	308.7
	Pressure	psia	1,924.4	1,909.6	1,904.7	1,932.4
	Enthalpy	BTU/lb	280.3	278.5	277.8	282.1
21	**IP Feedwater**					
	Flow	lb/hr	132,786	125,938	123,598	140,302
	Temperature	F	304.0	302.2	301.6	305.7
	Pressure	psia	497.2	483.8	479.2	510.9
	Enthalpy	BTU/lb	274.6	272.8	272.1	276.4
22	**Condensate Pump Discharge**					
	Flow	lb/hr	606,902	593,281	588,553	619,874
	Temperature	F	91.1	99.5	102.1	80.0
	Pressure	psia	87.8	84.3	83.1	91.8
	Enthalpy	BTU/lb	59.3	67.7	70.3	48.3
23	**Cooling Water From Condenser**					
	Flow	lb/hr	29,345,346	29,345,346	29,345,346	29,345,346
	Temperature	F	85.6	94.7	97.4	71.8
24	**Cooling Water To Condenser**					
	Flow	lb/hr	29,345,346	29,345,346	29,345,346	29,345,346
	Temperature	F	65.6	75.2	78.1	51.2
25	**Aux Cooling Water Supply**					
	Flow	lb/hr	5,000,004	5,000,004	5,000,004	5,000,004
	Temperature	F	65.6	75.2	78.1	51.2
26	**Aux Cooling Water Return**					
	Flow	lb/hr	5,000,004	5,000,004	5,000,004	5,000,004
	Temperature	F	85.6	92.9	95.1	74.6
27	**Plant Fuel Flow**					
	Flow	lb/hr	89,834	85,562	84,170	94,419
	Temperature	F	86.0	86.0	86.0	86.0
28	**GT Fuel Gas**					
	Flow Rate	lb/hr	89,834	85,562	84,170	94,419
	Temperature	F	368.0	368.0	368.0	368.0
	HHV Fuel Cons	MMBTU/hr	2,018	1,922	1,891	2,121
29	**Fuel Gas Heater Water Flow**					
	Flow	lb/hr	53,121.5	50,682.1	49,887.3	55,758.4
	Temperature	F	405.6	404.5	404.2	406.5

FIGURE 2.1-4BR
HEAT BALANCE DATA
LODI ENERGY CENTER - SUPPLEMENT D
LODI, CALIFORNIA

Source: Worley Parsons, LODI-1-HT-021-0001 RB, 8-28-08



HRSG Blowdown (%FW)	2%
RO Recovery (2 pass)	67%
EDI Recovery	95%
Circulating Water Flowrate	68,636
Cooling Tower Cycles of Concentration	7
Evap Cooler Cycles of Concentration	2
Condensate Polisher Flow (% FW flow)	50%
Blowdown quench (% of HRSG BD)	200%
Condensate Polisher Regeneration Loss	1%
Moisture entrained in solids (%product)	2%
Wash down Water (1 hose average)	20

	Annual Avg
Dry Bulb Temperature	61.2
Wet Bulb Temperature	54.8
Relative Humidity	0.67
Pressure	14.70
Feedwater Flow (lb/hr)	587,528
Feedwater Flow (gpm)	1174
Makeup Flow (lb/hr)	645,260
Makeup Flow (gpm)	1289
Evaporation Loss Flow (lb/hr)	516,200
Evaporation Loss Flow (gpm)	1032
Drift Loss Flow (lb/hr)	17,166.5
Drift Loss Flow (gpm)	34
Evap Cooler makeup (lb/hr)	0
Evap Cooler makeup (gpm)	0

* All flowrates shown are in gallons per minute unless otherwise noted.

Source: Worley Parsons LTD, 06-16-09

FIGURE 2.1-5AR
WATER BALANCE DIAGRAM, ANNUAL AVERAGE OPERATIONS
LODI ENERGY CENTER - SUPPLEMENT D
LODI, CALIFORNIA

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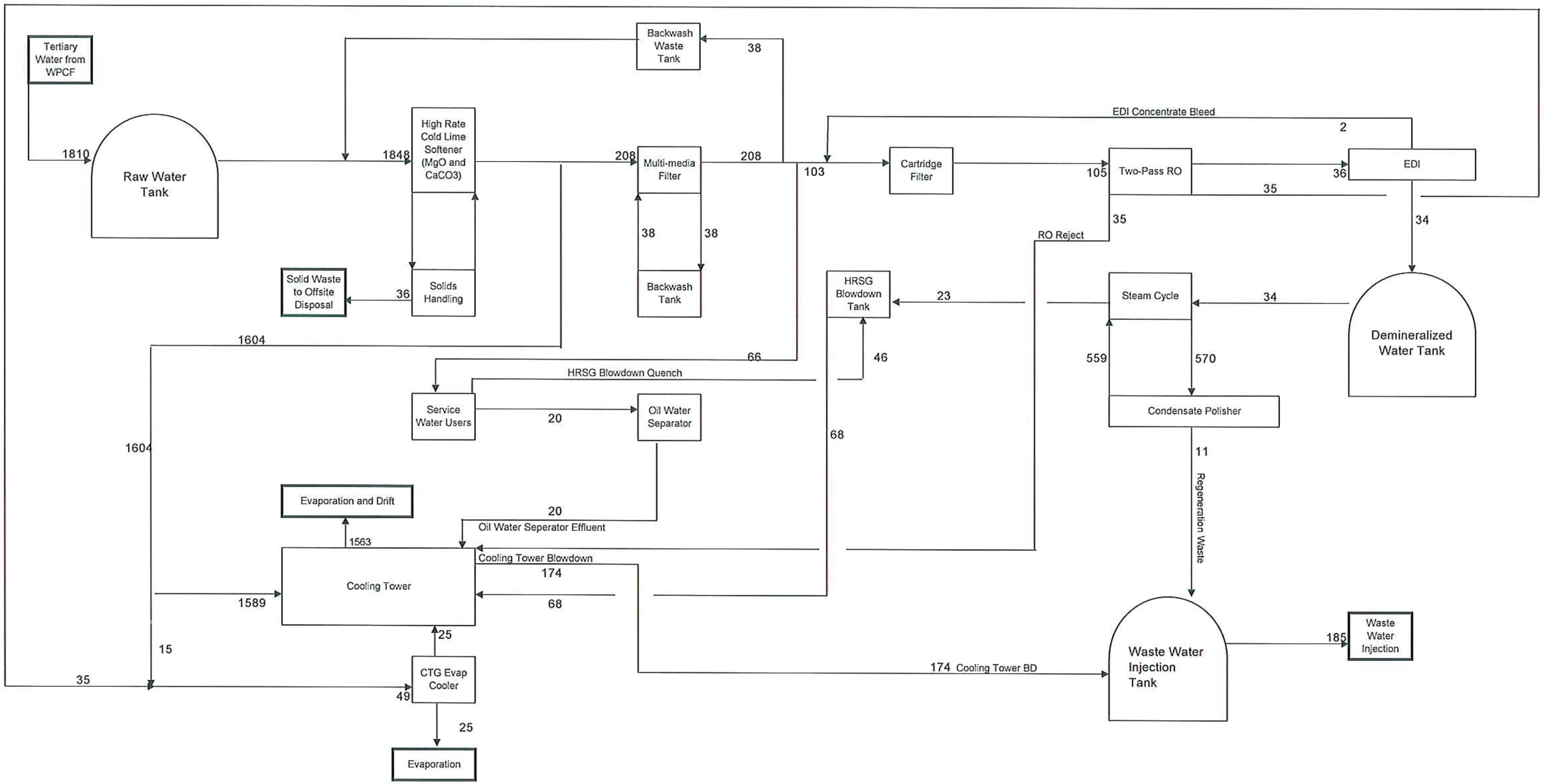

			Summer Max
HRSG Blowdown (%FW)	2%	Dry Bulb Temperature	107.7
RO Recovery (2 pass)	67%	Wet Bulb Temperature	72.9
EDI Recovery	95%	Relative Humidity	0.18
Circulating Water Flowrate	68,636	Pressure	14.70
Cooling Tower Cycles of Concentration	10	Feedwater Flow (lb/hr)	570,604
Evap Cooler Cycles of Concentration	2	Feedwater Flow (gpm)	1140
Condensate Polisher Flow (% FW flow)	50%	Makeup Flow (lb/hr)	959,559
Blowdown quench (% of HRSG BD)	200%	Makeup Flow (gpm)	1918
Condensate Polisher Regeneration Loss	1%	Evaporation Loss Flow (lb/hr)	767,640
Moisture entrained in solids (%product)	2%	Evaporation Loss Flow (gpm)	1534
Wash down Water (1 hose average)	20	Drift Loss Flow (lb/hr)	14,733.7
		Drift Loss Flow (gpm)	29
		Evap Cooler makeup (lb/hr)	24,686
		Evap Cooler makeup (gpm)	49

* All flowrates shown are in gallons per minute unless otherwise noted.

FIGURE 2.1-5BR
WATER BALANCE DIAGRAM, PEAK OPERATIONS
LODI ENERGY CENTER - SUPPLEMENT D
LODI, CALIFORNIA

Source: Worley Parsons LTD, 06-16-09

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NOTES:

1. THE 480 VOLT SWITCHGEAR DRAWOUT CIRCUIT BREAKERS CURRENT RATINGS ARE THE FRAME SIZE.
2. CIRCUIT BREAKERS AND CONTACTORS INDICATED BY "DCS" SHALL BE CONTROLLED FROM THE DCS.

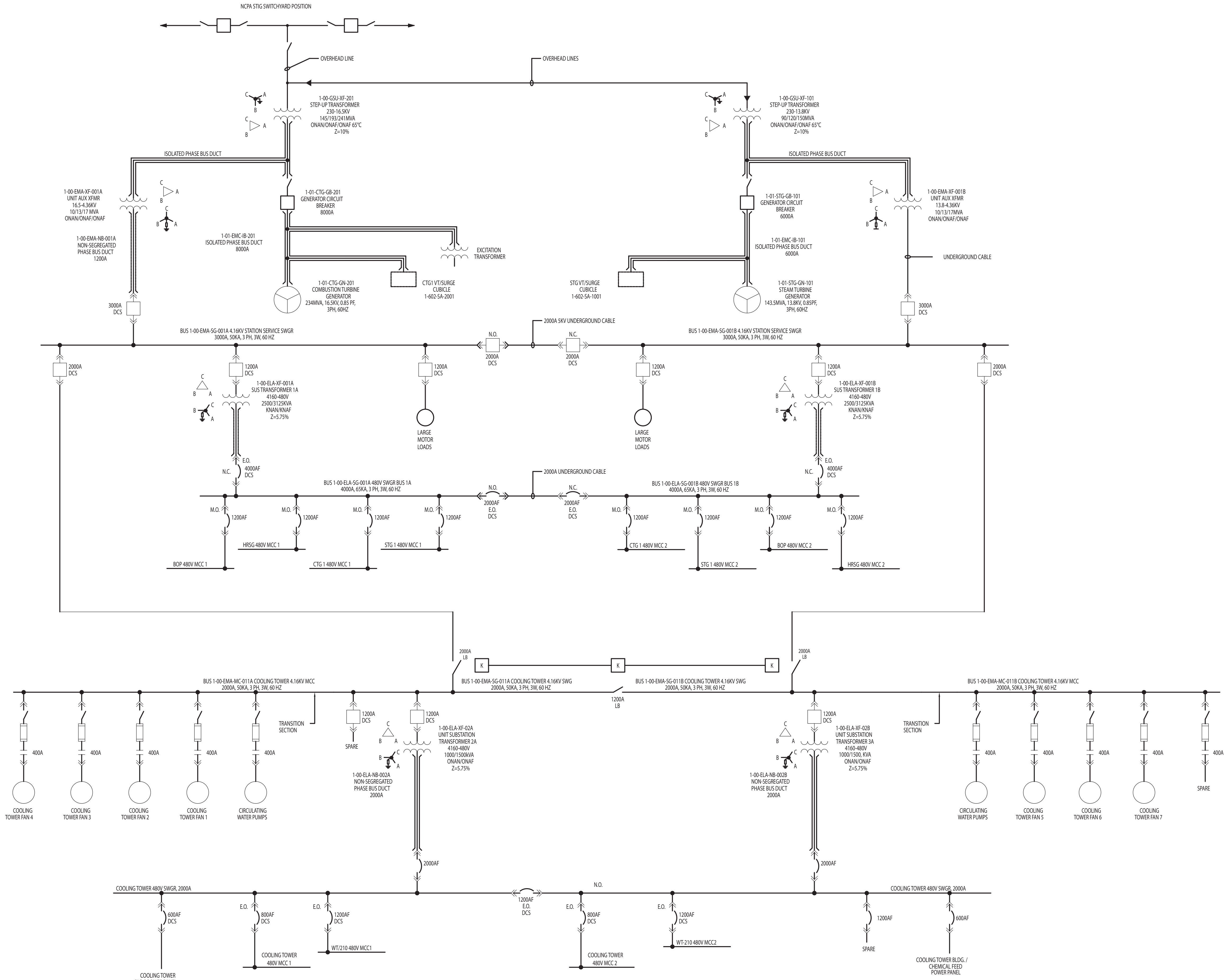


FIGURE 3.2-1R
ONE LINE DIAGRAM
LODI ENERGY CENTER - SUPPLEMENT D
LODI, CALIFORNIA

Source: Worley Parsons, LODI-0-SK-623-206-101E, 06-04-09

FIGURE 5.13-2A - View of project site from KOP 1 (from the southbound lane of I-5, north of the project site). The HRSG stack, tanks and buildings associated with the STIG facility are visible in the center of this view, beyond the WPCF treatment and holding ponds.

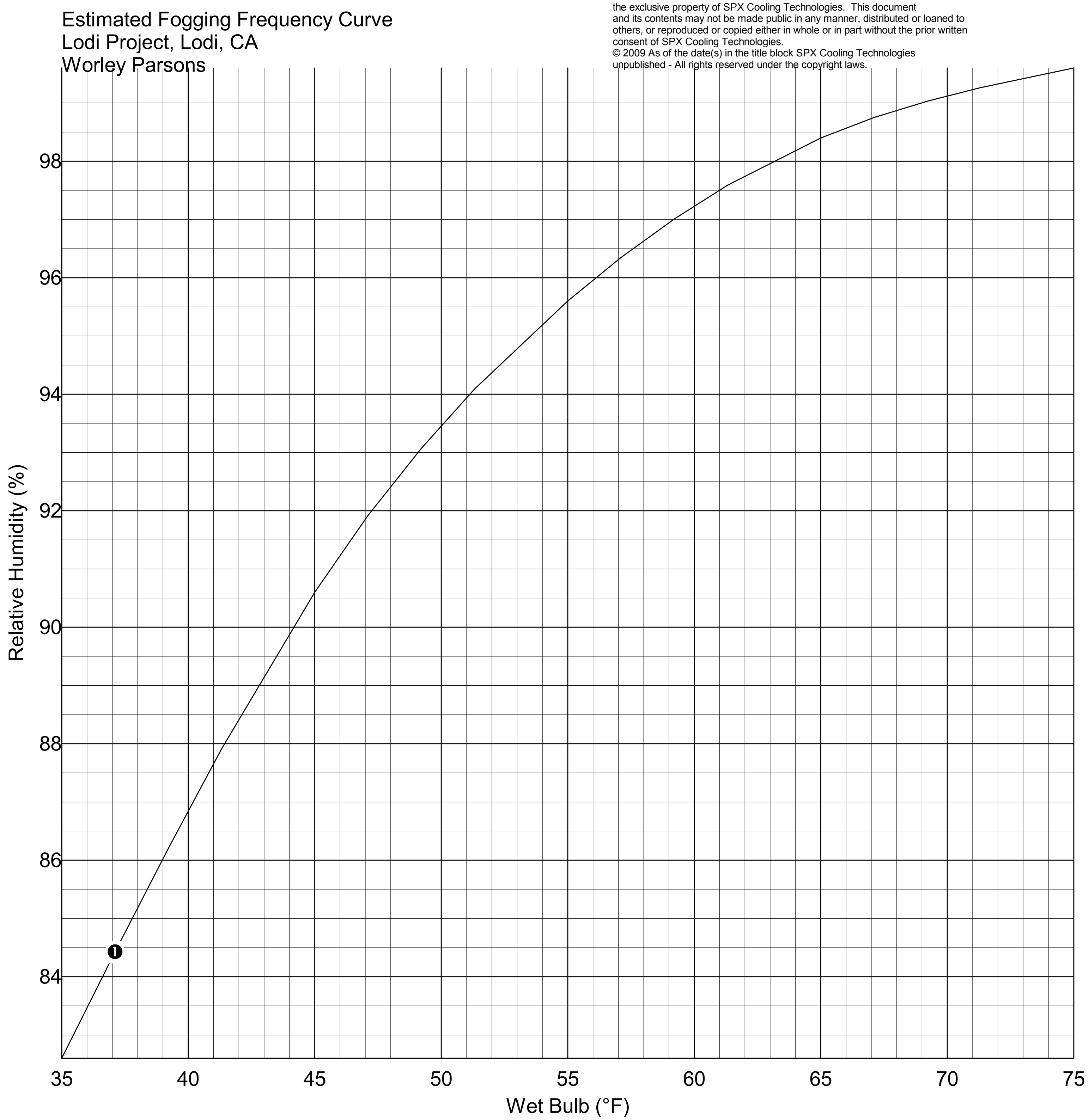
FIGURE 5.13-2B - Simulated view from KOP 1, with the proposed project.

FIGURE 5.13-2R
KEY OBSERVATION POINT 1
LODI ENERGY CENTER
LODI, CALIFORNIA

FIGURE 5.13-3A - View of project site from KOP 2 (from within the White Slough Wildlife Area, at the northeast corner of Pond 11, northwest of the project site). The HRSG stack and other structures associated with the STIG facility – including the switchyard – are visible in the center of this view. Structures associated with the WPCF are visible to the east (left) of the STIG facility.

FIGURE 5.13-3B - Simulated view from KOP 2, with the proposed project.

FIGURE 5.13-3R
KEY OBSERVATION POINT 2
LODI ENERGY CENTER
LODI, CALIFORNIA



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SPX Cooling Technologies
TRACS Version 18-SEP-08

Model	F478-6.0-7
Number of Cells	7
Motor Output	241.7HP
Motor RPM	1800
Fan	336HP7-9
Fan RPM	146
(Full Speed)	

Design Conditions:

Flow Rate	69000GPM
Hot Water	95.50°F
Cold Water	75.50°F
Wet-Bulb	68.90°F

Curve Conditions:

Fan Pitch	Constant
Flow Rate	69000GPM
(100% Design Flow)	

Tangency 100.0%

FOGGING FREQUENCY CURVE: The curve shown to the left is referred to as a 'Fogging Freqency Curve'. The Fogging Freqency Curve separates entering cooling tower conditions that produce fog at the discharge (Top-Left region of chart) from those that do not produce fog (Bottom-Right region of chart)

❶ 20 °F Range

Time: 10:29:35 Date: 06-17-2009 Drawn By: MDZ

FIGURE 3.13-1
FOGGING FREQUENCY CURVE
LODI ENERGY CENTER - SUPPLEMENT D
LODI, CALIFORNIA

Appendix A
Revised Project Description

SECTION 2.0

Project Description

The Lodi Energy Center (LEC) will be a combined-cycle nominal 296 96~~55-~~megawatt [1](MW) Siemens Flex Plant 30power generation facility consisting of a "~~Rapid Response~~" ~~GE Energy~~ Siemens STG6-5000F ~~Frame 7FA~~, natural gas-fired turbine-generator, a Siemens SST-900RH single condensing steam turbine, a 7-cell cooling tower, and associated balance-of-plant equipment. The facility will be located in Lodi, San Joaquin County, California, on a 4.4-acre parcel located adjacent to the City of Lodi's White Slough Water Pollution Control Facility (WPCF) and the existing 49-MW Northern California Power Agency (NCPA) Combustion Turbine Project #2 (STIG plant).[2]

2.1 Facility Description, Design, and Operation

2.1.1 Site Arrangement and Layout

Figure 2.1-1 shows the revised general arrangement and layout of the facility, and Figure 2.1-2 shows typical elevation views. Primary access to the site will be provided via North Thornton Road off Interstate 5.

The project site is adjacent to the WPCF to the east, treatment and holding ponds associated with the WPCF to the north, the existing 49-MW STIG plant to the west, and the San Joaquin County Mosquito and Vector Control facility to the south. The project site is on land owned and incorporated by the City of Lodi, and is approximately 6 miles from the Lodi city center. The city of Stockton is approximately 2 miles to the south. The project site is currently undeveloped and is used for equipment storage during upgrades to the WPCF. Construction laydown and parking areas will be within existing site boundaries of the WPCF on City-owned property. Four parcels totaling 9.8-acres will be used for both construction and laydown areas (as shown on Figure 2.1-3). Area A is approximately 3.1 acres, Area B is approximately 2.2 acres, Area C is approximately 1.6 acres, and Area D is approximately 2.9 acres.

2.1.2 Shared Facilities between the LEC and the STIG Plant

Because the STIG plant and the LEC plant will be adjacent to each other and both will be owned and operated by NCPA, some existing facilities will be shared between the two plants, while other facilities will require modification to allow for the LEC plant. Details on the shared facilities and the new and/or modified facilities are described below.

[1] ~~Maximum peak generating c~~ Capacity at 61 degrees Fahrenheit is 296 ~~85~~ MW.

[2] "STIG plant" refers to the NCPA Combustion Turbine Project, which is a steam turbine injected gas turbine (STIG) plant

2.1.2.1 Shared Existing Facilities

The following existing elements of the STIG plant's infrastructure will be shared between the two facilities:

- The anhydrous ammonia system, including both the 12,000-gallon storage tank and truck unloading facilities
- ~~The 230 kilovolt (kV) switchyard and interconnect~~
- The firewater storage and transfer system including two 250,000 gallon storage tanks and the firewater pump.
- The domestic water systems. ~~, including eye wash stations and emergency showers~~
- The existing Class I underground injection well (to be used for backup only)

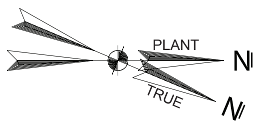
2.1.2.2 New or Modified Facilities

The following facilities will be modified or built as part of the LEC project.

- In the original project design, the existing commercial cooling tower for the STIG plant required relocation or replacement as it would interfere with the placement of the new plant equipment. As part of this revised project design, the decision was made to replace the existing STIG cooling tower with a small plate and frame heat exchanger to be located closer to the STIG plant thereby making way for the new plant equipment and improving the existing STIG plant cooling efficiency.~~The existing administration building, including the control room, office space, maintenance shop and communication systems. These facilities will be shared by both the LEC and STIG facilities.~~
- ~~The existing warehouse facilities. These facilities will be shared by both the LEC and STIG facilities.~~
- ~~The existing commercial cooling tower for the STIG plant will be temporarily relocated to accommodate the construction of the LEC plant, but will later be replaced by a permanent heat exchanger that will share the LEC cooling tower for cooling purposesnot be shared by both facilities~~
- The existing gas metering station for the STIG plant will be relocated to allow its expansion to accommodate the LEC plant. The metering yard will be shared by both facilities with a common metering run for billing purposes by the fuel gas supplier (PG&E). However, since the existing STIG plant and the new plant are technically under separate ownership, for internal billing to the separate NCPA parties, ~~but~~ each facility will have its own ~~dedictated~~ dedicated metering run.
- The existing 230kV switchyard will be shared by both the existing STIG and LEC facilities. An additional HV circuit breaker and other equipment will be added to the existing switchyard to accommodate the LEC. ~~will not be shared by both facilities~~

The remaining facilities and activities at the STIG plant will not be shared between the two-sites, are not part of the LEC project, and, therefore, have not been considered in this Application for Certification (AFC).

PLANT SITE DESCRIPTION



1	COMBUSTION TURBINE/GENERATOR
2	HRSG
3	STEAM TURBINE/GENERATOR
4	COOLING TOWER
5	GSUT
6	GAS METERING AREA
7	WATER TREATEMENT BUILDING
8	COOLING TOWER CHEM TOTES
9	DEMINERALIZED WATER TANK
10	CEMS BUILDING
11	STIG PLANT COOLING TOWER (TEMPORARY)
12	ELECT SWGR ROOM
13	OIL/WATER SEPARATOR
14	BOILER FEED WATER PUMPS
15	BOILER BLOWDOWN TANK
16	COOLING TOWER CHEM FEED TANK
17	GEN. CIRCUIT BREAKER
18	RAW WATER TANK
19	STG / HRSG PDC
20	CTG PDC
21	STEAM TURBINE SOUND ENCLOSURE
22	STACK
23	4160V UNIT AUX. TRANSFORMER
24	EXCITATION TRANSFORMER
25	COOLING WATER PUMP STRUCTURE
26	U/G CIRCULATING WATER PIPING
27	EXISTING INJECTION WELL
28	NCPA WAREHOUSE EXTENSION (NEW)
29	POTABLE WATER WELL
30	480V SUS TRANSFORMER
31	REPLACEMENT WELL (FUTURE)
32	INJECTION WELL HEAD
33	FUEL GAS PERFORMANCE HEATER
34	INJECTION WATER STORAGE TANK
35	AMMONIA SKID
36	AUXILIARY BOILER
37	AMMONIA STORAGE TANK (EXISTING)
38	FIRE PUMP (EXISTING)
39	HYDRAULIC SKID
40	CONTROL ROOM (EXISTING)
41	ROTOR AIR COOLER
42	MAIN ENTRANCE
43	SECONDARY ENTRANCE
44	NH3 FORWARDING SKID
45	STIG PLANT COOLING WATER PUMPS (TEMPORARY)
46	FIREWATER TANK (EXISTING)
47	FIREWATER TANK (EXISTING)
48	DEMIN. WATER TANK (EXISTING)
49	R.O. WATER STORAGE TANK (EXISTING)
50	R.O. WATER STORAGE TANK (EXIST.)
51	WASTE TANK (EXISTING)
52	GAS COMPRESSORS
53	RELOCATED GAS COMP.
54	GAS COMPRESSOR FILTER
55	TRANSMISSION TOWER
56	GAS COMP. AFTERCOOLER
57	FUEL GAS FILTER/SEPARATOR
58	HYDRAULIC SUPPLY SKID
59	CONDENSATE EXTRACTION PUMPS
60	LUBE OIL SKID
61	GLAND STEAM SKID/CONDENSER
62	VACUUM PUMPS
63	SEE/SFC PACKAGE & TRANSFORMERS
64	VT & SURGE CUBICLE
65	ELECTRICAL PACKAGE
66	DEW POINT HEATER
67	G. T. LUBE OIL SKID
68	DEMIN WATER TRANS. PUMPS
69	S. T. DRAIN TANK
70	
71	
72	HEAT EXCHANGER
73	GLAND STEAM CONDENSER

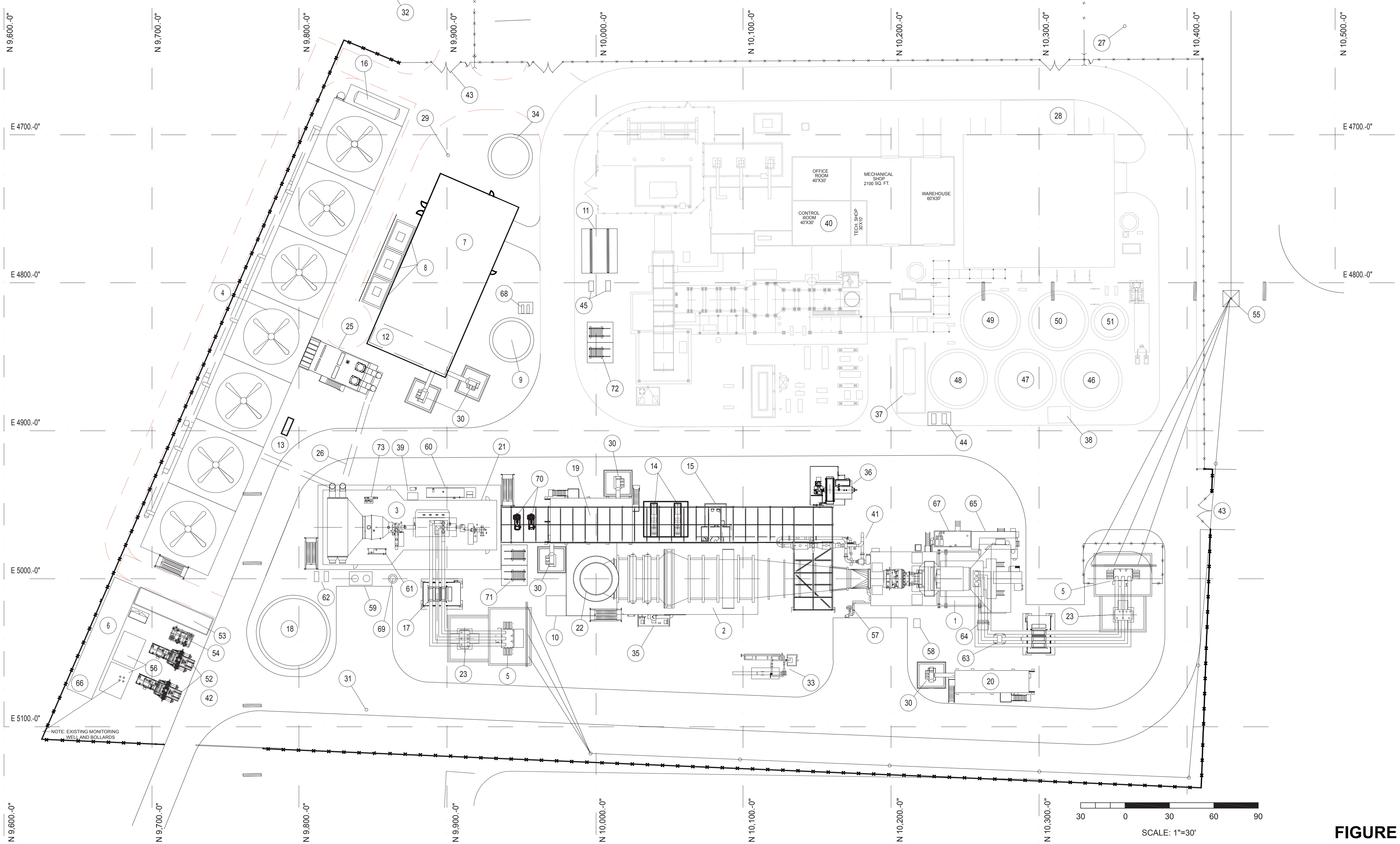
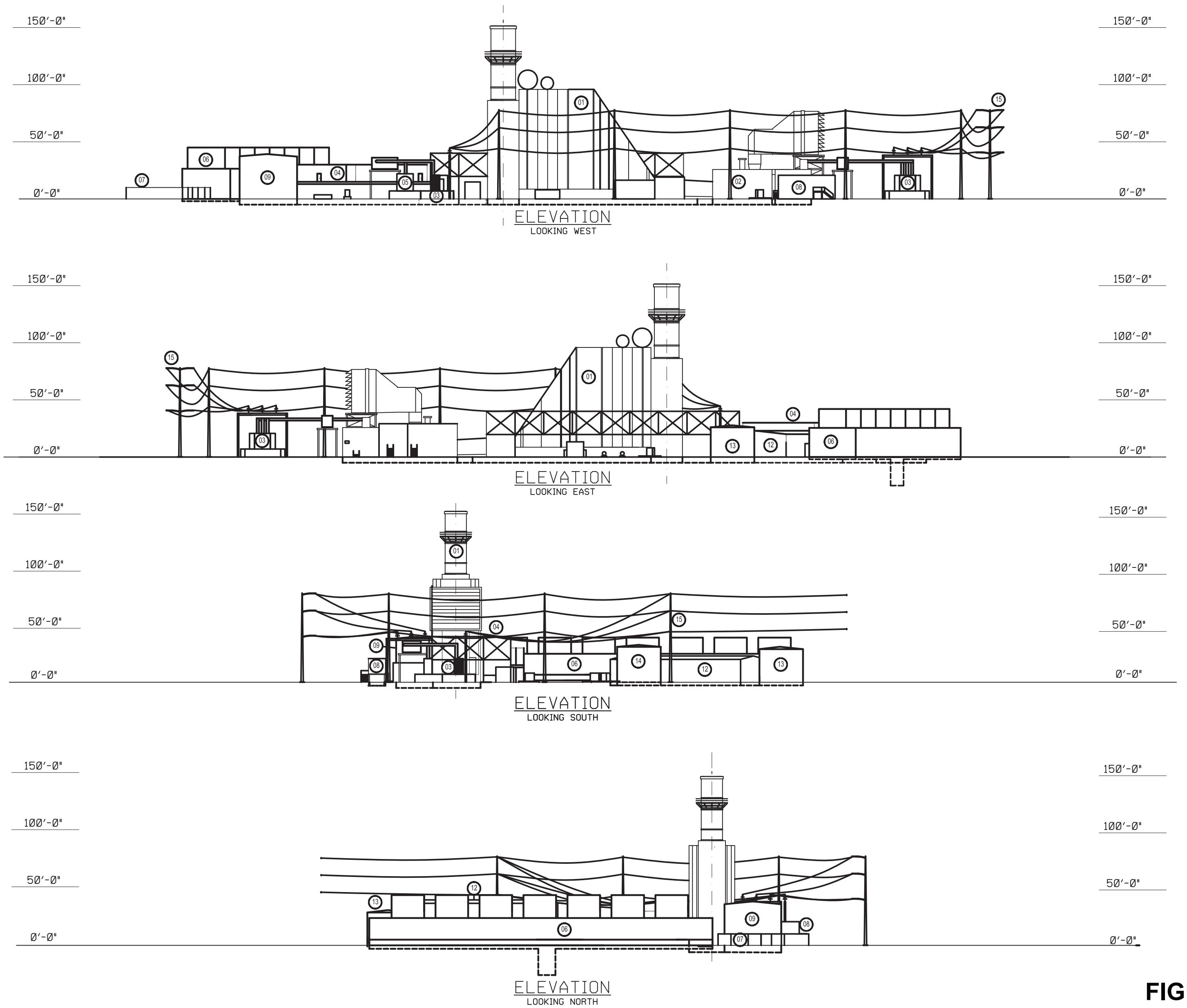


FIGURE 2.1-1R
GENERAL ARRANGEMENT
LODI ENERGY CENTER - SUPPLEMENT D
LODI, CALIFORNIA

Source: Worley Parsons LTD, Drawing LODI-0-DW-111-007-002A, 6-4-09



LEGEND:
01- HRSG
02- COMBUSTION TURBINE GENERATOR
03- GENERATOR STEP-UP TRANSFORMER
04- STEAM TURBINE GENERATOR
05- UNIT AUX TRANSFORMER
06- COOLING TOWER
07- GAS COMPRESSORS
08- PDC
09- RAW WATER STORAGE TANK
10- NOT USED
11- NOT USED
12- WATER TREATMENT BUILDING
13- WASTE WATER STORAGE TANK
14- DEMINERALIZED WATER TANK
15- TRANSMISSION TOWER

NOTES:
ELEVATION DRAWINGS ARE REFERENCING PLANT NORTH

40 0 40 80 120
SCALE: 1" = 40'

FIGURE 2.1-2R
ELEVATIONS
LODI ENERGY CENTER - SUPPLEMENT D
LODI, CALIFORNIA

Source: Worley Parsons LTD, LODI-0-SK-111-002-101D, 07-24-09

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CH2MHILL

This map was compiled from various scale source data and maps and is intended for use as only an approximate representation of actual locations.

0 150 300
Feet

N

FIGURE 2.1-3
PROPOSED LAYDOWN AND PARKING AREAS
LODI ENERGY CENTER
LODI, CAIFORNIA

CH2MHILL

SAC\\ZION\SACGIS\PROJ\LODIENERGYCENTER_371322\MAPFILES\PROPOSEDLAYDOWNAREAS.MXD MHASKELL 9/3/2008 14:34:38

2.1.3 Activities Not Part of the Project

2.1.3.1 NCPA Combustion Turbine Project Number 1 Staff Relocation Project

NCPA currently operates its Combustion Turbine Project Number 1 (CTG1), which consists of five combustion turbines located on three sites. Two combustion turbines are in Roseville, one combustion turbine is in Lodi, and two combustion turbines are in Alameda. The City of Roseville will be taking over the operation and maintenance of the two combustion turbines in Roseville, and as a result, NCPA will be relocating seven of its employees from the Roseville site to the Lodi STIG plant site. This relocation requires remodeling of the existing STIG administration building to accommodate these employees. This remodeling effort will involve converting the warehouse portion of the existing administration building to usable office space. This, in turn, requires construction of a new warehouse to replace the converted warehouse space and to house the parts and equipment currently stored at the Roseville site. To facilitate the relocation project, a temporary trailer for office space and document storage will be placed on the STIG site until the remodeling of the administration building is complete. The relocation project will be permitted by the City of Lodi and construction is expected to occur in 2009 to facilitate the move in 2009. Although the LEC will ultimately share the use of the remodeled administration building and new warehouse, this activity will take place with or without the LEC and, therefore, is not part of the LEC project.

2.1.3.2 WPCF Ongoing Activities

The LEC site is currently being used by the City of Lodi as a construction staging and equipment storage area for ongoing WPCF expansion and maintenance projects. These activities are not part of the LEC project; they are being performed by the City of Lodi and are not dependent on the LEC moving forward.

2.1.3.3 STIG Plant Ammonia Tank Upgrade Project

As part of its Risk Management Plan (RMP) review, the STIG plant is currently updating the existing anhydrous ammonia storage system. The project will not increase storage capacity, but the storage system will be configured with active and passive measures designed to meet a performance standard of reducing the offsite consequence analysis to less than 75 parts per million (ppm) at the closest public receptor. This project will be completed before the LEC becomes operational and will be undertaken whether or not the LEC moves forward.

2.1.4 Process Description

The LEC power train will consist of the following components: (1) one “~~Rapid Response~~” ~~General Electric (GE) Energy~~ Siemens STG6-5000F~~Frame 7FA~~ combustion turbine-generator (CTG) installed in a Flex Plant 30 configuration, equipped with dry low NO_x combustors for the control of NO_x, and an evaporative cooler for reducing inlet air temperatures; (2) one heat recovery steam generator (HRSG)~~ with duct burners~~; (3) selective catalytic reduction (SCR) and oxidation catalyst equipment to control NO_x and carbon monoxide (CO) emissions, respectively; (4) a condensing steam turbine generator (STG); (5) a deaerating surface condenser; (6) a 7-cell mechanical draft cooling tower; (7) a small auxiliary boiler (~27~~45~~,6~~0~~00 lb/hr); and (8) associated support equipment.

The CTG will use ~~"Rapid Response Fast Start" technology offered by GESiemens~~"Flex Plant ™30" technology offered by Siemens, the supplier of the project's combustion turbine equipment. This technology allows for faster starting of the gas turbines by mitigating the restrictions of older HRSG designs. Traditionally, CTGs are started up slowly, with long hold times at low load points, to limit combined stresses in the high-pressure steam drum of the HRSG and to maintain steam conditions for the steam turbine. The ~~Rapid~~ "~~Fast Start~~ Flex Plant ™" ~~Response~~ technology eliminates this restriction by modifying the HRSG ~~HP steam drum~~ design. The proposed boiler is a "Benson Boiler" design that does not include an HP drum but does include redesigned intermediate pressure and low pressure drums. Therefore, warmup times for the boiler are kept to a minimum. The ~~Rapid ResponseFlex Plant~~ project~~package~~ includes an auxiliary boiler that preheats the CTG fuel and provides STG sealing steam, among other functions, prior to CTG startup; thereby, allowing the ST condenser vacuum to be established and the condenser to be in a condition ready to accept steam earlier in the startup cycle. This allows earlier startup of the steam turbine and helps to shorten hold times for the CTG.

The CTG will generate approximately ~~170.9~~200.8 MW at annual average ambient conditions. The CTG exhaust gases will be used to generate steam in the HRSG; no duct firing will be utilized. The HRSG will employ a triple-steam-pressure design. ~~with duct firing equipment~~. Steam from the HRSG will be admitted to a condensing STG. The STG will produce approximately ~~96.4~~100.9 -MW under average annual ambient conditions ~~with no HRSG duct firing~~. The project is expected to have an overall annual availability of more than 95 percent.

The heat balance for the power plant's baseload operation assuming the use of ~~GE Energy~~ Siemens STG6-5000F~~7FA~~ CTG is shown in Figures 2.1-4A and 2.1-4B. This balance is based on operation at an ambient temperature of 61.2 degrees Fahrenheit (°F), with evaporative cooling of the CTG inlet air to 55.8°F~~, and without the use of duct firing~~. The predicted net electrical output of the facility under these conditions is approximately ~~261.3~~295.6 MW at a heat rate of approximately 6,824~~797~~ British thermal units per kilowatt hour (Btu/kWh) on a higher heating value (HHV) basis. This corresponds ~~with~~ to an efficiency of about 55.6 percent. ~~With HRSG duct firing, the facility will be able to produce a net output of up to 285.3 MW at an ambient temperature of 61.2°F with evaporative cooling of the CTG inlet air to 55.8°F using the GE 7FA. The incremental heat rate of the peaking capacity will be approximately 8,773 Btu/kWh, corresponding to an efficiency of 43.3 percent, which is comparable to that of a CTG operating in simple-cycle mode.~~

The combustion turbine and associated equipment will include the use of best available control technology (BACT) to limit emissions of criteria pollutants and hazardous air pollutants. As with the original project design, NO_x will be controlled to 2.0 ppm by volume, dry basis (ppmvd), corrected to 15 percent oxygen through the use of dry low-NO_x combustors and an SCR system using ammonia injection. Good combustion practices and -a CO catalyst will also be used to control CO emissions to 3.0 ppm at 15 percent oxygen. Because there will be no duct firing, e~~E~~missions of volatile organic compounds (VOCs) will ~~also be controlled~~ limited to ~~2.0~~ 1.4 ppm. -BACT for -PM_{10} and SO_2 will be the exclusive use of natural gas. Ammonia slip will be limited to 10 ppm.

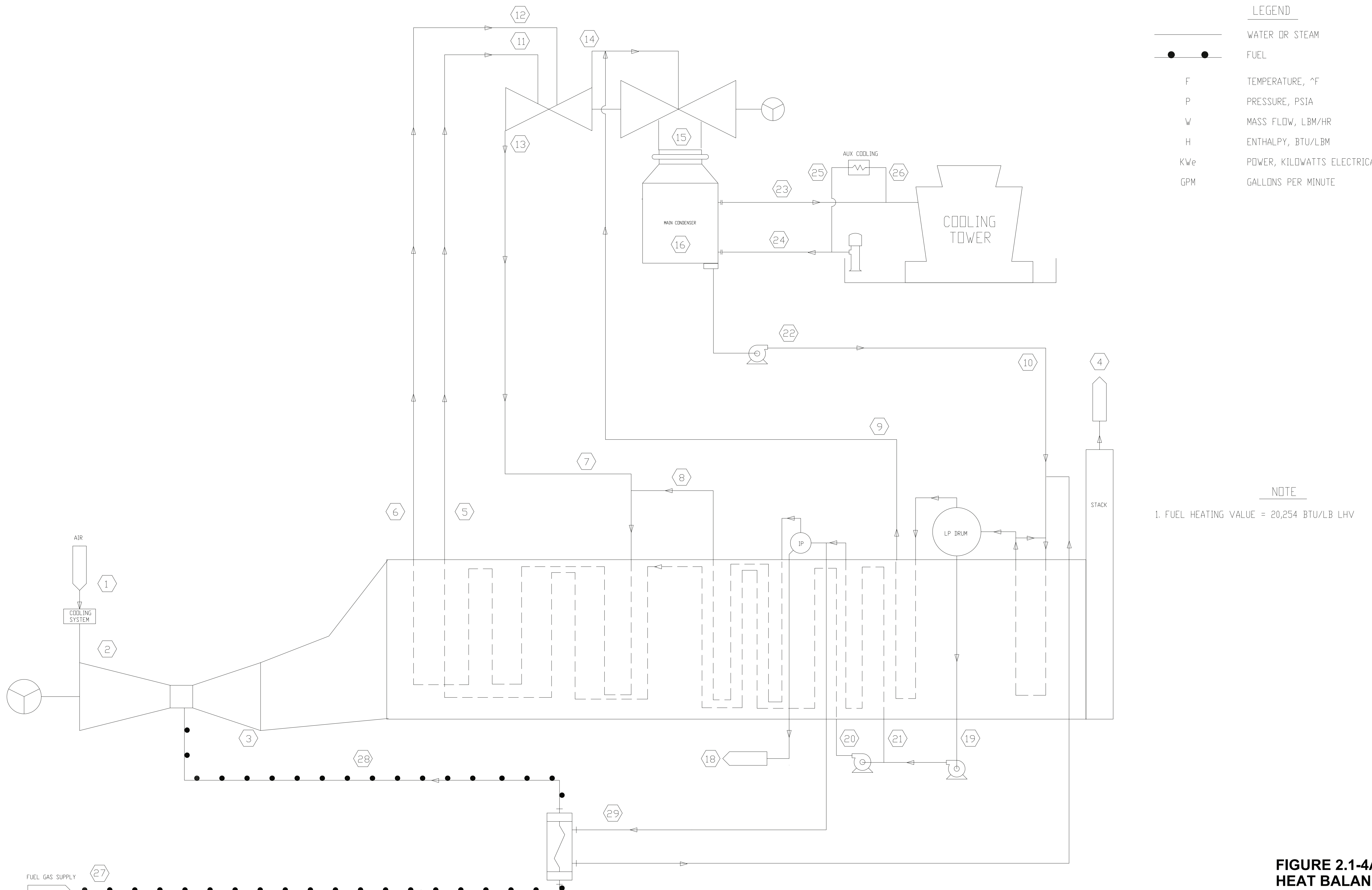


FIGURE 2.1-4AR
HEAT BALANCE DIAGRAM
LODI ENERGY CENTER - SUPPLEMENT D
LODI, CALIFORNIA

Source: Worley Parsons, LODI-1-HT-021-0001 RB, 6-4-09

Case		Plant Net Power	Net Cycle LHV Heat Rate	Net Cycle HHV Heat Rate	Gross Gas Turbine Power	ST Generator Output	Steam Cycle BOP Losses	Total LHV Fuel Cons.	Total HHV Fuel Cons.
		MW	BTU/kW-hr	BTU/kW-hr	MW	kW	kW	MMBTU/hr	MMBTU/hr
Annual Avg		298.5	6,096	6,761	202.1	102,865	6,500	1,820	2,018
Summer Typ	Evap ON	283.7	6,108	6,774	188.9	101,309	6,500	1,733	1,922
Summer Max	Evap ON	278.7	6,118	6,785	184.5	100,654	6,500	1,705	1,891
Winter Typ		312.7	6,115	6,782	215.6	103,610	6,500	1,912	2,121

Stream ID	Case	UOM	Annual Avg	Summer Typ Evap ON	Summer Max Evap ON	Winter Typ
1	**Ambient Conditions**					
	Dry Bulb Temperature	F	61.2	94.0	107.7	32.6
	Wet Bulb Temperature	F	54.8	68.9	72.9	29.7
	Relative Humidity		0.668	0.275	0.182	0.740
	Pressure	psia	14.7	14.7	14.7	14.7
2	**GT Compressor Inlet**					
	Air Flow	lb/hr	3,925,576	3,752,863	3,694,609	4,106,534
	Air Temperature	F	61.2	72.6	78.0	32.6
3	**CTG 1 Exhaust**					
	Flow	lb/hr	4,015,410	3,838,424	3,778,779	4,200,954
	Temperature	F	1,078.0	1,094.0	1,100.0	1,060.0
4	**HRSG Stack Exit**					
	Flow	lb/hr	4,015,410	3,838,424	3,778,779	4,200,954
	Temperature	F	183.2	184.3	184.5	181.5
	Pressure	psia	14.5	14.6	14.6	14.5
	Enthalpy	BTU/lb	31.0	31.5	31.6	30.5
5	**HP Steam From HRSG**					
	Flow	lb/hr	454,742	448,942	447,006	459,296
	Temperature	F	1,012.2	1,024.9	1,029.6	998.1
	Pressure	psia	1,807.5	1,795.3	1,791.4	1,813.5
	Enthalpy	BTU/lb	1,487.9	1,496.0	1,499.1	1,479.0
6	**HRH Steam From HRSG**					
	Flow	lb/hr	532,813	522,693	519,243	542,148
	Temperature	F	1,005.8	1,018.3	1,023.0	991.7
	Pressure	psia	401.1	395.3	393.4	406.0
	Enthalpy	BTU/lb	1,526.3	1,533.1	1,535.7	1,518.6
7	**CRH Steam To HRSG**					
	Flow	lb/hr	454,742	448,942	447,006	459,296
	Temperature	F	647.5	656.4	659.8	637.7
	Pressure	psia	418.8	412.8	410.7	423.9
	Enthalpy	BTU/lb	1,333.2	1,338.6	1,340.6	1,327.3
8	**IP Steam From HRSG**					
	Flow	lb/hr	78,071	73,751	72,236	82,852
	Temperature	F	613.8	613.5	613.5	613.5
	Pressure	psia	418.8	412.8	410.8	423.9
	Enthalpy	BTU/lb	1,313.9	1,314.3	1,314.4	1,313.4
9	**LP Steam From HRSG**					
	Flow	lb/hr	74,088	70,588	69,309	77,726
	Temperature	F	512.2	509.4	508.5	515.0
	Pressure	psia	66.6	65.0	64.5	68.1
	Enthalpy	BTU/lb	1,288.6	1,287.4	1,287.0	1,289.8
10	**Condensate To HRSG**					
	Flow	lb/hr	661,611	645,469	639,916	677,323
	Temperature	F	93.8	101.4	103.8	83.8
	Pressure	psia	87.8	84.3	83.1	91.8
	Enthalpy	BTU/lb	62.1	69.6	72.0	52.1
11	**HP Steam To STG**					
	Flow	lb/hr	454,742	448,942	447,006	459,296
	Temperature	F	1,009.2	1,022.0	1,026.8	995.0
	Pressure	psia	1,748.2	1,736.4	1,732.6	1,754.0
	Enthalpy	BTU/lb	1,487.9	1,496.0	1,499.1	1,479.0
12	**HRH Steam To STG**					
	Flow	lb/hr	532,814	522,693	519,243	542,148
	Temperature	F	1,004.3	1,016.9	1,021.6	990.2
	Pressure	psia	374.6	369.2	367.4	379.2
	Enthalpy	BTU/lb	1,526.3	1,533.1	1,535.7	1,518.6
13	**CRH Steam From STG**					
	Flow	lb/hr	454,742	448,942	447,006	459,296
	Temperature	F	648.2	657.0	660.4	638.4
	Pressure	psia	424.0	418.0	415.9	429.0
	Enthalpy	BTU/lb	1,333.2	1,338.6	1,340.6	1,327.3
14	**IP STG Exhaust**					
	Flow	lb/hr	74,088	70,588	69,309	77,726
	Temperature	F	510.9	508.3	507.4	513.7
	Pressure	psia	59.9	58.8	58.4	60.9
	Enthalpy	BTU/lb	1,288.6	1,287.4	1,287.0	1,289.8

Stream ID	Case	UOM	Annual Avg	Summer Typ Evap ON	Summer Max Evap ON	Winter Typ
15	**STG Exhaust**					
	Flow	lb/hr	606,902	593,281	588,553	619,874
	Temperature	F	90.6	99.0	101.6	79.6
	Pressure	psia	0.7	0.9	1.0	0.5
	Enthalpy	BTU/lb	1,023.1	1,028.5	1,031.3	1,020.3
16	**Condenser Hotwell**					
	Flow	lb/hr	606,902	593,281	588,553	619,874
	Temperature	F	90.6	99.0	101.6	79.6
	Pressure	psia	0.7	0.9	1.0	0.5
	Enthalpy	BTU/lb	58.6	67.0	69.6	47.6
17	**HP Blowdown**					
	Flow	lb/hr	0	0	0	0
	Temperature	F	-	-	-	-
	Pressure	psia	-	-	-	-
	Enthalpy	BTU/lb	-	-	-	-
18	**IP Blowdown**					
	Flow	lb/hr	1,593	1,505	1,474	1,691
	Temperature	F	458.3	456.1	455.4	460.3
	Pressure	psia	459.0	449.4	446.1	468.3
	Enthalpy	BTU/lb	439.6	437.2	436.3	441.9
19	**BFP Suction**					
	Flow	lb/hr	587,528	574,880	570,604	599,598
	Temperature	F	302.8	301.0	300.4	304.5
	Pressure	psia	69.9	68.0	67.4	71.6
	Enthalpy	BTU/lb	272.6	270.8	270.1	274.3
20	**HP Feedwater**					
	Flow	lb/hr	454,742	448,942	447,006	459,296
	Temperature	F	307.0	305.2	304.6	308.7
	Pressure	psia	1,924.4	1,909.6	1,904.7	1,932.4
	Enthalpy	BTU/lb	280.3	278.5	277.8	282.1
21	**IP Feedwater**					
	Flow	lb/hr	132,786	125,938	123,598	140,302
	Temperature	F	304.0	302.2	301.6	305.7
	Pressure	psia	497.2	483.8	479.2	510.9
	Enthalpy	BTU/lb	274.6	272.8	272.1	276.4
22	**Condensate Pump Discharge**					
	Flow	lb/hr	606,902	593,281	588,553	619,874
	Temperature	F	91.1	99.5	102.1	80.0
	Pressure	psia	87.8	84.3	83.1	91.8
	Enthalpy	BTU/lb	59.3	67.7	70.3	48.3
23	**Cooling Water From Condenser**					
	Flow	lb/hr	29,345,346	29,345,346	29,345,346	29,345,346
	Temperature	F	85.6	94.7	97.4	71.8
24	**Cooling Water To Condenser**					
	Flow	lb/hr	29,345,346	29,345,346	29,345,346	29,345,346
	Temperature	F	65.6	75.2	78.1	51.2
25	**Aux Cooling Water Supply**					
	Flow	lb/hr	5,000,004	5,000,004	5,000,004	5,000,004
	Temperature	F	65.6	75.2	78.1	51.2
26	**Aux Cooling Water Return**					
	Flow	lb/hr	5,000,004	5,000,004	5,000,004	5,000,004
	Temperature	F	85.6	92.9	95.1	74.6
27	**Plant Fuel Flow**					
	Flow	lb/hr	89,834	85,562	84,170	94,419
	Temperature	F	86.0	86.0	86.0	86.0
28	**GT Fuel Gas**					
	Flow Rate	lb/hr	89,834	85,562	84,170	94,419
	Temperature	F	368.0	368.0	368.0	368.0
	HHV Fuel Cons	MMBTU/hr	2,018	1,922	1,891	2,121
29	**Fuel Gas Heater Water Flow**					
	Flow	lb/hr	53,121.5	50,682.1	49,887.3	55,758.4
	Temperature	F	405.6	404.5	404.2	406.5

Source: Worley Parsons, LODI-1-HT-021-0001 RB, 8-28-08

FIGURE 2.1-4BR
HEAT BALANCE DATA
LODI ENERGY CENTER - SUPPLEMENT D
LODI, CALIFORNIA

CH2MHILL

2.1.5 Power Plant Cycle

CTG combustion air will flow through the inlet air filters, evaporative cooler and associated air inlet ductwork, be compressed in the CTG compressor section, and then enter the CTG combustion section. Natural gas fuel will be injected into the compressed air in the combustion section and ignited. The hot combustion gases will expand through the power turbine section of the CTG, causing it to rotate and drive both the electric generator and CTG compressor. The hot combustion gases will exit the turbine sections and enter the HRSG, where they will heat feedwater that is pumped into the HRSG. The feedwater will be converted to superheated steam and delivered to the steam turbine at high pressure (HP), intermediate pressure (IP), and low pressure (LP). The use of multiple steam delivery pressures will permit an increase in cycle efficiency and flexibility. High-pressure steam will be delivered to the HP section of the steam turbine, intermediate pressure steam will augment the reheat section of the HRSG and will deliver this steam to the IP section of the STG, LP steam will be injected at the beginning of the LP section of the steam turbine, and both flows will be expanded in the LP steam turbine section. Steam leaving the LP section of the steam turbine will enter the deaerating surface condenser and transfer heat to circulating cooling water, which will cause the steam to condense to water. The condensed water, or condensate, will be delivered to the HRSG feedwater system. The condenser cooling water will circulate through a mechanical draft evaporative cooling tower where the heat absorbed in the condenser will be rejected to the atmosphere.

2.1.6 Major Generating Facility Components

The following paragraphs describe the major components of the generating facility.

2.1.6.1 Combustion Turbine Generators

Thermal energy will be produced in the CTG through the combustion of natural gas, which will be converted into mechanical energy required to drive the combustion turbine compressor and electric generator. The CTG system will consist of a CTG with supporting systems and associated auxiliary equipment. The ~~Rapid Response~~~~Fast Start~~ Siemens SGT6-5000[3]F~~GE Energy Frame 7FA~~ CTG uses dry low NO_x combustors to ~~lower~~ reduce turbine-out NO_x emissions.

The CTG will be equipped with the following required accessories to provide safe and reliable operation:

- Inlet air filters and evaporative cooler
- Metal acoustical enclosure
- Lube oil system for the combustion turbine and generator
- Dry low NO_x combustion system
- Compressor wash system—both online and offline
- Fire detection and protection system (using carbon dioxide)
- Fuel gas system, including flow meter, strainer, and duplex filter
- Starter system
- Turbine controls
- TEWAC (totally enclosed air to water cooled) ~~Hydrogen-cooled,~~ synchronous generator

[3] SGT6-5000F refers to the combustion turbine, while SCC6-5000F refers to the Siemens 1x1 combined cycle unit.

- Generator controls, protection, excitation, power system stabilizer, and automatic generation control (AGC)

The CTG and accessory equipment will be contained in a metal acoustical enclosure as required to meet sound noise ordinances.

2.1.6.2 Heat Recovery Steam Generator

The HRSG will transfer heat from the exhaust gases of the CTG to the feedwater, which will become steam. The HRSG will be a triple-pressure, reheat, natural circulation unit equipped with inlet and outlet ductwork, ~~duct burners,~~ insulation, lagging, and an exhaust stack.

Major heat transfer components of the HRSG will include one LP economizer, one LP evaporator, one LP drum, one LP superheater, two IP economizers, one IP evaporator, one IP drum, two IP superheaters, two HP economizers, one HP evaporator, ~~one HP drum~~, and two HP superheaters and reheat sections. The LP economizer will receive condensate from the condenser hot well via the condensate pumps. The LP economizer will be the final heat transfer section to receive heat from the combustion gases before it is exhausted to the atmosphere.

Condensate will be directed through the LP economizer and into the LP drum. The boiler HP and IP feed pumps, drawing suction from the LP drum, will provide additional pressure to serve the HP and IP sections of the HRSG. Similarly, as described above, the LP, IP, and HP steam will be produced for supply to the steam turbine.

Intermediate-pressure feedwater will flow through the IP economizers to the IP steam drum, where a saturated liquid state will be maintained. Next, the saturated water will flow from the steam drum through downcomers to the inlet headers of the IP evaporator. The saturated water will flow upward through the IP evaporator tubes by natural circulation. Saturated steam will form in the tubes while energy from the combustion turbine exhaust gas is absorbed. The IP-saturated liquid/vapor mixture will then return to the steam drum, where the two phases will be separated by the steam separators in the drum. The saturated water will return to the IP evaporator while the vapor passes to the IP superheater inlet. The saturated steam (vapor) will pass through the IP superheaters to the IP steam turbine inlet.

High-pressure feedwater will flow through the HP ~~steam drum~~evaporator, where ~~a~~ the saturated liquid will change state to form a saturated vapor~~will be maintained~~. ~~Next, the saturated water will flow from the steam drum through downcomers to the inlet header of the HP evaporator.~~ The saturated ~~water~~ vapor will flow ~~upward~~ through the HP evaporator tubes by natural circulation ~~. Saturated steam will form in the tubes while energy from the combustion turbine exhaust gas is absorbed. The HP saturated liquid/vapor mixture~~ and ~~will then return to the steam drum, where the two phases~~ will be separated by the steam separators ~~in the drum~~. T~~he saturated water will return to the HP evaporator while t~~he vapor passes to the HP superheater inlet. The saturated steam (vapor) will pass through the HP superheaters to the HP steam turbine inlet.

The LP evaporator will function similarly to the HP and IP evaporators. The saturated LP steam (vapor) will pass through the LP superheater to the LP steam turbine inlet.

~~A duct burner system will be installed in the HRSG that can be used to increase steam generation and operating flexibility and will improve steam temperature control. The duct burner system will burn natural gas. The duct burner system for the HRSG will be sized to release up to approximately 220 million British thermal units per hour (MMBtu/hr) on an HHV basis.~~

The HRSG will be equipped with an SCR emission control system that will use ammonia vapor in the presence of a catalyst to reduce the NO_x concentration in the exhaust gases. The catalyst module will be located in the HRSG casing. Diluted ammonia vapor (NH_3) will be injected into the exhaust gas stream through a grid of nozzles located upstream of the catalyst module. The subsequent chemical reaction will reduce most of the NO_x to nitrogen and water. An oxidation catalyst will control CO emissions.

2.1.6.2.1 Steam Turbine System

The SST-900RH steam turbine system will consist of a condensing steam turbine, gland steam system, lubricating oil system, hydraulic control system, and steam admission/induction valving. The steam turbine will drive a TEWAC (totally enclosed, water to air cooled) ~~hydrogen-cooled~~, synchronous generator.

Steam from the HRSG HP, IP, and LP superheaters will enter the respective steam turbine sections through the inlet steam system. The steam will expand through the turbine blading, driving the generator. On exiting the turbine, the steam will flow into the axial exhaust condenser.

2.1.6.2.2 Auxiliary Boiler

An~~The~~ auxiliary boiler will be used during pre-start activities and during the initial phases of start-up to generate steam for sealing, heating/re-heating the hotwell condensate (condenser sparging steam), and heating the gas turbine fuel gas. The auxiliary boiler is designed to control delivery pressure and steam quality over a broad range of steam demands. The Siemens Flex Plant™ system has a lower steam demand during startup than the original GE equipment, so the auxiliary boiler proposed for the new configuration is smaller than the boiler originally proposed. However, to provide additional operational flexibility for facility cycling, the revised air quality and public health analyses include more hours of auxiliary boiler operation than assumed in the original project design.

~~The minimum steam demand normally occurs during pre-start activities when supplying seal steam only to the steam turbine glands before condenser vacuum is established (approximately 20,000 lb/hr). Maximum demand occurs when supplying maximum steam turbine sealing steam, maximum condenser sparge steam, maximum feedwater heating steam, and gas turbine inlet air heating (approximately 45,000 lb/hr). Therefore, the auxiliary boiler steam supply system includes a pressure control system that vents to the atmosphere to limit auxiliary boiler operating pressures during periods of low steam demands and/or rapid reductions in steam consumption during transients. The auxiliary boiler is designed to achieve a turndown ratio of 4:1.~~

The auxiliary boiler will be equipped with ultra-low NO_x burners to reduce NO_x emissions and will be fueled with natural gas exclusively to minimize emissions of other criteria and non-criteria pollutants.

2.1.7 Major Electrical Equipment and Systems

The bulk of the electric power produced by the facility will be transmitted to the electrical grid through the existing 230-kV, double-circuit line adjacent to NCPA's existing 49-MW STIG plant. A small amount of electric power will be used on site to power auxiliaries such as pumps and fans, control systems, and general facility loads including lighting, heating, and air conditioning. A station battery system will also be used to provide direct current (DC) voltage to be used as backup power for control systems and other uses. Transmission and auxiliary uses are discussed in the following subsections.

2.1.7.1 AC Power—Transmission

Power will be generated by the CTG and the STG at ~~1~~16.5 and 13.8~~8~~ kV respectively and then stepped up to 230kV by individual ~~a single,~~ fan-cooled, two~~hree~~-winding, generator step-up (GSU) transformers ~~to 230 kV~~ for connection to the grid. Auxiliary power will be back-fed through each of the step-up transformers. Once the unit is running, it will supply its own auxiliary power. Surge arresters will be provided at the transformer high-voltage bushings to protect the transformer from surges on the 230-kV system caused by lightning strikes or other system disturbances. Each of t~~T~~he GSU transformers will be set on a concrete pad within a berm designed to contain the non-PCB transformer oil in the event of a leak or spill. The high-voltage side of each of the step-up transformers will be connected via an overhead transmission line to a single new ring bus position in the existing 230kV substation that will be created by the installation of a new gas insulated (SF6) circuit breaker ~~to be installed in the existing 230kV substation and connected via an overhead transmission line~~. The STG GSU transformer will be connected to the overhead transmission line. From the substation, power will be transmitted to the grid via transmission lines owned by Pacific Gas and Electric Company (PG&E). Section 3.0, Electrical Transmission, contains additional information regarding the electrical transmission system as well as a summary of the System Impact Study.

2.1.7.2 AC Power—Distribution to Auxiliaries

Auxiliary power to the combustion turbine will be supplied at 4,160 volts and 480-volt alternating current (AC) by 4,160-volt switchgear lineups and 480-volt switchgear lineups. Two~~,~~ ~~oil-filled using less flammable oil, 18- to~~ 4.16-kV unit auxiliary stepdown oil-filled (using less flammable oil) transformers will supply primary power to the switchgear and then subsequently to large motor loads including the fuel gas compressors and to the 4.16 kV side of the 4.16-kV/480-volt, ~~oil-filled~~ load center transformers. The high-voltage side of the unit auxiliary transformers will be connected to a tap on the isolated phase bus duct ~~or cable~~ connecting the generator to the respective GSU low-voltage (secondary) winding. This connection will allow the switchgear to be powered from the local grid via the GSU whenever the CTG is not running or directly from the CTG when the CTG is running. A generator circuit breaker located near the CTG and the STG will be connected to each of the generators. The circuit breaker is used to isolate and synchronize the generators, and will be located between the generators and the connections to the GSU. The 4,160-volt switchgear lineup will supply power to the fuel gas compressors, other large motor loads, the combustion turbine starting system, and to the load center transformers, rated 4,160 to 480 volts, for 480-volt power distribution. The 4.16-kV switchgear will utilize~~have~~ vacuum interrupter circuit breakers for the main incoming feeds and for power distribution.

Each 480 volt load center transformer will be dry type~~oil-filled using less flammable oil~~, using no oil, and will supply 480-volt, 3-phase power to the plant 480-volt motor control centers (MCCs) and switchgear.

The MCCs will provide power to the various 480-volt motor loads, and other low-voltage plant loads including 480-volt power distribution panels, and lower voltage lighting and distribution panel transformers. Power for the AC power supply (120-volt/208-volt) system will be provided by the 480-volt MCCs and 480-volt power panels. 480-120/208-volt dry-type transformers will provide transformation of 480-volt power to 120/208-volt power.

2.1.7.3 125~~/250~~-Volt DC Power Supply System

One common 125~~/250~~-volt DC power supply system consisting of one 100-percent-capacity battery bank, two 100-percent-capacity static battery chargers, a switchboard, and two or more distribution panels will be supplied for balance-of-plant and CTG equipment. The CTG will be provided with its own separate battery systems and redundant chargers.

Under normal operating conditions, the battery chargers supply DC power to the DC loads. The battery chargers receive 480-volt, three-phase AC power from the AC power supply (480-volt) system and continuously charge the battery banks while supplying power to the DC loads.

Under abnormal or emergency conditions, when power from the AC power supply (480-volt) system is unavailable, the batteries supply DC power to the DC system loads. Recharging of a discharged battery occurs whenever 480-volt power becomes available from the AC power supply (480-volt) system. The rate of charge depends on the characteristics of the battery, battery charger, and the connected DC load during charging. The anticipated maximum recharge time will be 12 hours.

2.1.7.4 Uninterruptible Power Supply System

The combustion turbine and power block will also have an essential service 120-volt AC, single-phase, 60-hertz (Hz) uninterruptible power supply (UPS) to supply AC power to essential instrumentation, to critical equipment loads and to unit protection and safety systems that require uninterruptible AC power.

~~Redundant~~ The UPS inverter~~s~~ will supply 120-volt AC single-phase power to the UPS panel boards that supply critical AC loads. The UPS inverter~~s~~ will be fed from the station 125~~/250~~-volt DC power supply system. ~~Each~~ The UPS system will consist of one full-capacity inverter, a static transfer switch, a manual bypass switch, an alternate source transformer, and two or more panelboards.

The normal source of power to the system will be from the 125-volt DC power supply system through the inverter to the panelboard. A solid-state static transfer switch will continuously monitor both the inverter output and the alternate AC source. The transfer switch will automatically transfer essential AC loads without interruption from the inverter output to the alternate source upon loss of the inverter output.

A manual bypass switch will also be included to enable isolation of the inverter for testing and maintenance without interruption to the essential service AC loads.

The distributed control system (DCS) operator stations will be supplied by UPS power. The continuous emission monitoring system (CEMS) equipment, DCS controllers, and input/output (I/O) modules will be fed using either UPS or 125-volt DC power directly.

2.1.8 Fuel System

The CTG will be designed to burn natural gas only. The natural gas requirement during base load operation at annual average ambient temperature is approximately ~~12,018857~~1,957~~-~~ MMBtu/hr (higher heat value [HHV] basis). The maximum natural gas requirement, experienced during low ambient-temperature operation, is approximately 2131~~2,159079~~ MMBtu/hr (HHV basis).

Natural gas will be delivered from PG&E's Line #108 to the site via a new 2.5-mile-long pipeline, which will be adjacent to the existing natural gas pipeline used to serve the STIG plant. At the plant site, the natural gas will flow through a flow-metering station, gas scrubber/filtering equipment, a gas pressure control station, and a compressor that will boost the fuel gas pressure to that required by the CT ~~steam-heated fuel gas heater~~ prior to entering the combustion turbine.

Historical data indicate that the fuel gas pressure on PG&E's Line #108 generally varies between 300 and 400 pounds per square inch gauge (psig). Two 100-percent-capacity, electric-driven fuel gas compressors will be provided to boost the fuel gas pressure to about 500 psig, which is the pressure required by the combustion turbine. The gas compressors will be located outdoors and will be treated acoustically either by acoustical enclosures or a soundwall to reduce the compressor noise level.

2.1.9 Plant Cooling Systems

The steam turbine cycle heat rejection system will consist of a deaerating steam surface condenser ~~deaerating steam surface condenser~~, cooling tower, and cooling water (circulating water) system. The heat rejection system will receive exhaust steam from the low-pressure steam turbine and condense it to water (condensate) for reuse. The~~A~~ surface condenser is a shell-and-tube heat exchanger; the steam condenses on the shell side, and the cooling water flows through the tubes, making one or more passes. The condenser will be designed to operate at a pressure of approximately 2 inches of mercury, absolute at an ambient temperature of 61.2°F. Approximately ~~542~~ 590 MMBtu/hr of heat will be transferred from condensing steam to cooling water in the condenser.

The cooling water will circulate through a counter-flow, 7-cell, mechanical draft cooling tower~~7-cell, mechanical draft cooling tower~~ that uses electric motor-driven fans to move air in a direction opposite to the flow of the cascading water. Due to the HP design and requirements of the Benson type boiler, the cooling water flow through the cooling tower increased about 15% from 60,000 gpm to 69,000 gpm. The heat ~~removed~~ transferred in the condenser to the cooling (circulating) water will be discharged to the atmosphere by routing the cooling water through the cooling tower where the hot water is cooled by air flowing through the tower thereby heating the air and evaporating some of the cooling water. High efficiency drift eliminators will reduce drift (the fine mist of water droplets entrained in the warm air leaving the cooling tower) to 0.0005 percent of the circulating water flow.

2.1.10 Water Supply and Use

This subsection describes the quantity of water required, the sources of the water supply, and water treatment requirements. Figure 2.1-5A is a schematic water process flow diagram and Figure 2.1-5B is the schematic water process flow diagram calculations. ~~Table 2.1-1 shows water use characteristics keyed to the process flow diagram for (1) the average annual case (61.2°F dry bulb temperature and 66.8 percent relative humidity) and (2) the summer maximum case (107.7°F and 18.2 percent relative humidity). Both cases assume evaporative cooling in operation and duct burning not in operation. The table shows water usage for the GE 7FA~~Siemens SGT6-5000F~~. Complete water balance tables, including additional cases assuming other temperature, humidity, and operating regimes, are found in Appendix 2A.~~

~~**TABLE 2.1-1**~~
~~Water Use Characteristics Keyed to the Process Flow Diagram (Figure 2.1-5)~~

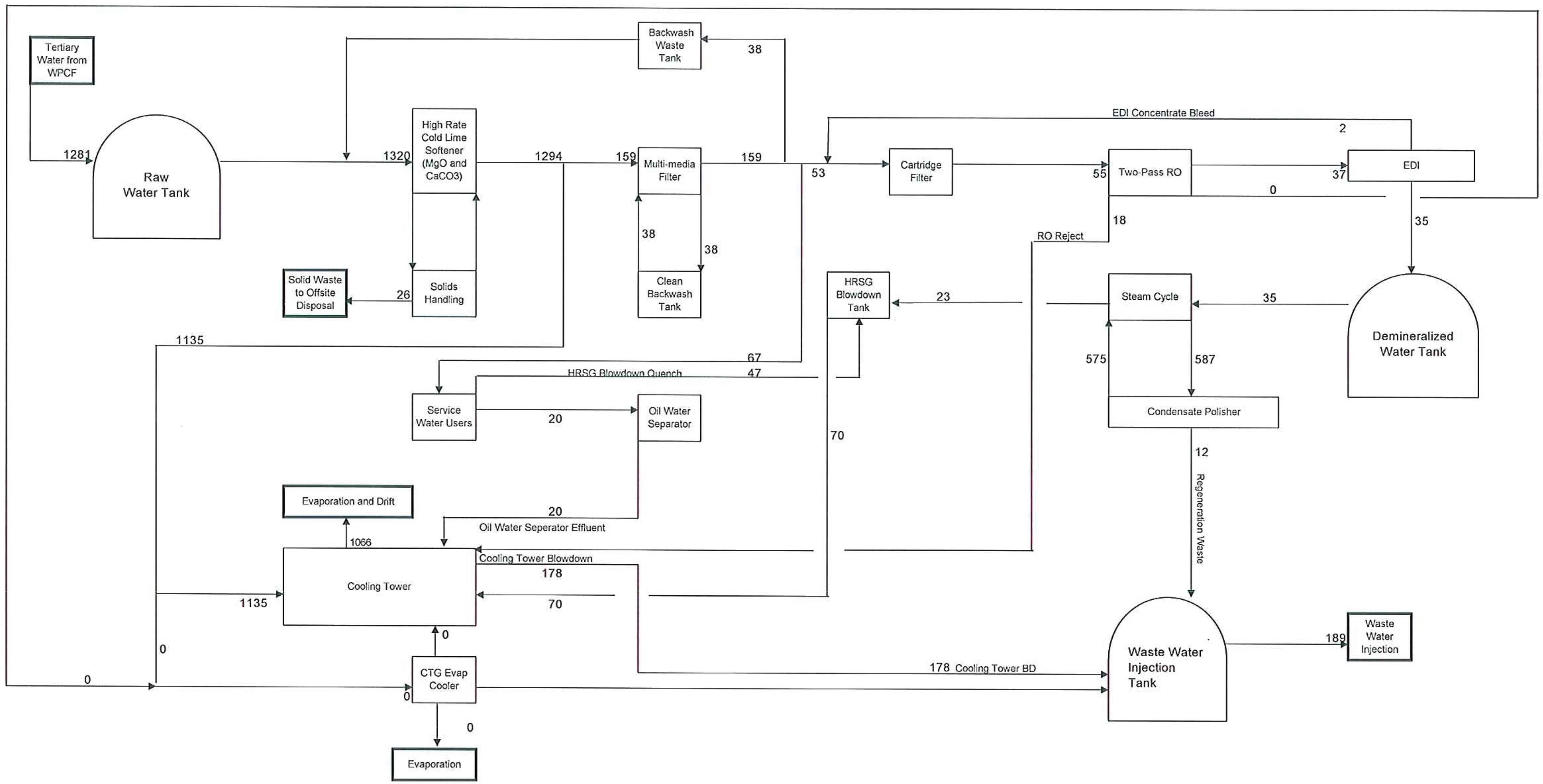
~~Figure 2.1-5 Identifier~~	~~Stream Description~~	~~Annual Average 61.2°F DB, 66.8% RH~~	~~Summer Max Flow~~ (Fired) ~~107.7°F DB, 18.2% RH~~
~~1~~	~~Influent from Wastewater Treatment Plant~~	~~856~~	~~1528~~
~~2~~	~~Potable Water Inlet~~	~~1~~	~~1~~
~~4~~	~~Eye Wash/Safety Shower/Drinking Water~~	~~1~~	~~1~~
~~6~~	~~CTG Evaporative Cooler Makeup~~	~~11~~	~~54~~
~~7~~	~~CTG Evaporative Cooler Blowdown~~	~~2~~	~~9~~
~~8~~	~~CTG Evaporative Cooler Evaporation~~	~~9~~	~~45~~
~~9~~	~~Micro-Filtration Feed~~	~~1008~~	~~1784~~
~~10~~	~~Micro-Filtration Blowdown~~	~~101~~	~~178~~
~~11~~	~~Micro-Filtration Filtrate~~	~~907~~	~~1606~~
~~12~~	~~Clarifier Feed~~	~~846~~	~~1518~~
~~13~~	~~1st Pass RO Feed~~	~~103~~	~~137~~
~~14~~	~~1st Pass RO Reject~~	~~26~~	~~34~~
~~15~~	~~1st Pass RO Permeate~~	~~77~~	~~103~~
~~16~~	~~Cooling Tower Feed~~	~~804~~	~~1469~~
~~17~~	~~2nd Pass RO Feed~~	~~35~~	~~42~~
~~18~~	~~2nd Pass RO Reject~~	~~3~~	~~4~~
~~19~~	~~2nd Pass RO Permeate (EDI Feed)~~	~~31~~	~~38~~
~~20~~	~~EDI Product~~	~~28~~	~~34~~
~~21~~	~~EDI Reject~~	~~3~~	~~4~~
~~25~~	~~Wastewater to Injection Well~~	~~103~~	~~183~~
~~26~~	~~HRSG Cycle Makeup~~	~~28~~	~~34~~
~~27~~	~~HRSG Unrecovered Losses~~	~~3~~	~~3~~
~~28~~	~~HRSG Sampling Losses~~	~~5~~	~~5~~
~~29~~	~~HRSG Blowdown (before cooling)~~	~~20~~	~~26~~
~~30~~	~~HRSG Blowdown (after cooling)~~	~~48~~	~~60~~

~~TABLE 2.1-1~~
~~Water Use Characteristics Keyed to the Process Flow Diagram (Figure 2.1-5)~~

~~Figure 2.1-5 Identifier~~	~~Stream Description~~	~~Annual Average 61.2°F DB, 66.8% RH~~	~~Summer Max Flow~~ (Fired) ~~107.7°F DB, 18.2% RH~~
~~31~~	~~HRSG Vent Flashing Losses~~	~~18~~	~~23~~
~~32~~	~~HRSG Blowdown Quench Water~~	~~41~~	~~52~~
~~34~~	~~Plant Washwater~~	~~10~~	~~10~~
~~35~~	~~Oil-Water Separator Effluent~~	~~11~~	~~11~~
~~36~~	~~Cooling Tower Evaporation~~	~~788~~	~~1394~~
~~37~~	~~Cooling Tower Drift~~	~~0.3~~	~~0~~
~~38~~	~~Cooling Tower Blowdown~~	~~197~~	~~348~~
~~39~~	~~Blowdown RO Pre-Filter Waste~~	~~10~~	~~17~~
~~40~~	~~Blowdown RO Feed~~	~~187~~	~~331~~
~~41~~	~~Blowdown RO Reject~~	~~93~~	~~165~~
~~42~~	~~Blowdown RO Permeate~~	~~93~~	~~165~~
~~43~~	~~Clarified Water~~	~~984~~	~~1764~~
~~44~~	~~Filtered Water~~	~~955~~	~~1711~~
~~45~~	~~Gravity Filter Backwash~~	~~39~~	~~71~~
~~46~~	~~Clarifier Sludge Blowdown~~	~~30~~	~~55~~
~~47~~	~~Clarifier Decant~~	~~21~~	~~38~~
~~48~~	~~Thickener Sludge Blowdown~~	~~9~~	~~16~~
~~49~~	~~Filter Press Filtrate~~	~~7~~	~~13~~
~~50~~	~~Filter Cake~~	~~1.8~~	~~3~~
~~51~~	~~Clarifier Recycle~~	~~68~~	~~122~~

~~DB = dry bulb~~
~~RH = relative humidity~~

The LEC will receive recycled water provided by the City of Lodi's WPCF. The project will access this water through an existing 48-inch-diameter pipeline in the utility corridor connecting the LEC and the WPCF. Sanitary sewer connections will also be provided through existing connections in this utility corridor to the WPCF. Potable water for sanitary and domestic use will be provided by a new onsite potable water well. The LEC facility will produce no non-reclaimable process wastewater, as it will dispose of process wastewater using a new Class I underground injection well (UIW), with the existing Class I UIW at the STIG plant used for backup. A will serve letter from the City of Lodi is provided as Appendix 2D.



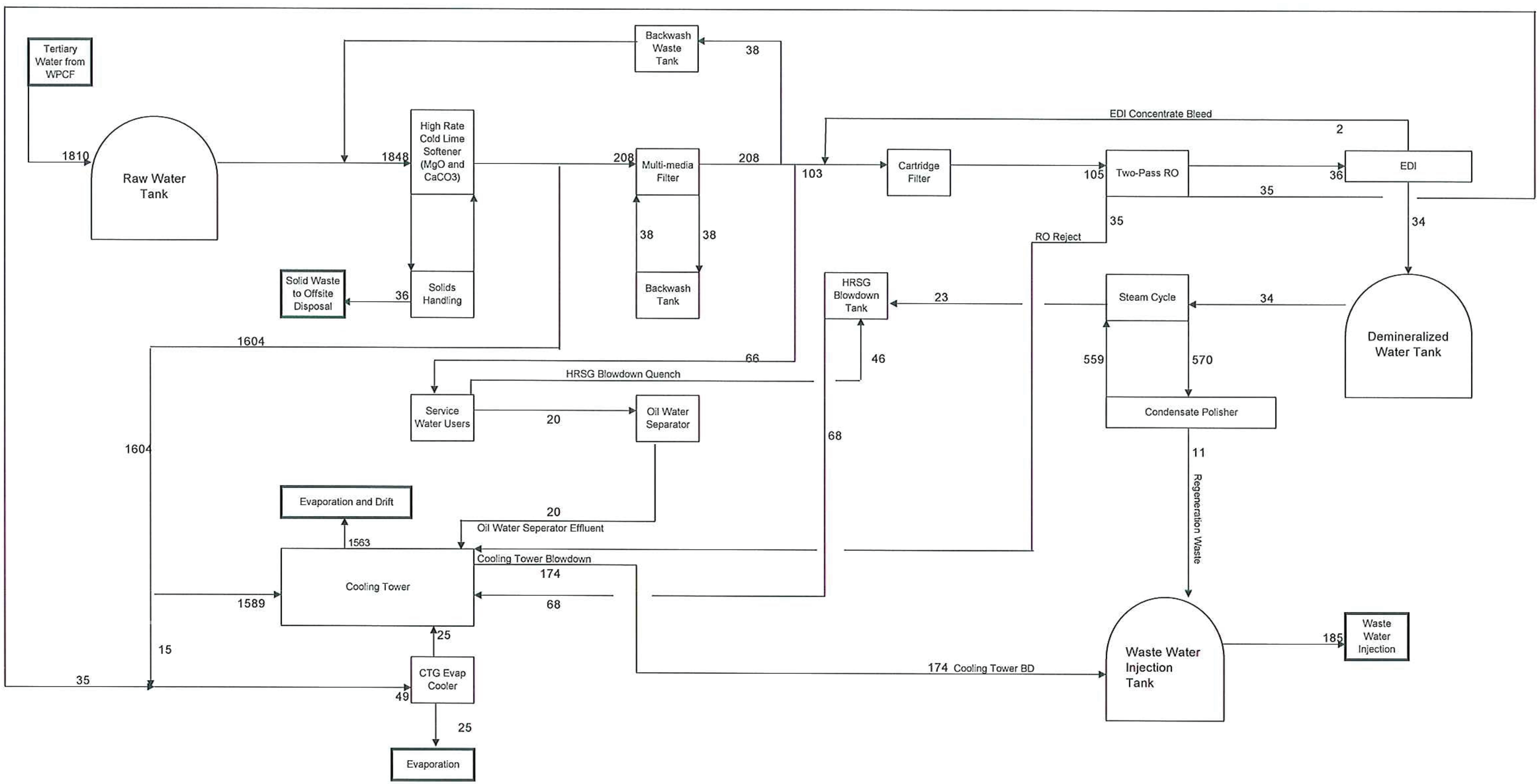
* All flowrates shown are in gallons per minute unless otherwise noted.

HRSG Blowdown (%FW)	2%
RO Recovery (2 pass)	67%
EDI Recovery	95%
Circulating Water Flowrate	68,636
Cooling Tower Cycles of Concentration	7
Evap Cooler Cycles of Concentration	2
Condensate Polisher Flow (% FW flow)	50%
Blowdown quench (% of HRSG BD)	200%
Condensate Polisher Regeneration Loss	1%
Moisture entrained in solids (%product)	2%
Wash down Water (1 hose average)	20

	Annual Avg
Dry Bulb Temperature	61.2
Wet Bulb Temperature	54.8
Relative Humidity	0.67
Pressure	14.70
Feedwater Flow (lb/hr)	587,528
Feedwater Flow (gpm)	1174
Makeup Flow (lb/hr)	645,260
Makeup Flow (gpm)	1289
Evaporation Loss Flow (lb/hr)	516,200
Evaporation Loss Flow (gpm)	1032
Drift Loss Flow (lb/hr)	17,166.5
Drift Loss Flow (gpm)	34
Evap Cooler makeup (lb/hr)	0
Evap Cooler makeup (gpm)	0

FIGURE 2.1-5AR
WATER BALANCE DIAGRAM, ANNUAL AVERAGE OPERATIONS
LODI ENERGY CENTER - SUPPLEMENT D
LODI, CALIFORNIA

Source: Worley Parsons LTD, 06-16-09



			Summer Max
HRSG Blowdown (%FW)	2%	Dry Bulb Temperature	107.7
RO Recovery (2 pass)	67%	Wet Bulb Temperature	72.9
EDI Recovery	95%	Relative Humidity	0.18
Circulating Water Flowrate	68,636	Pressure	14.70
Cooling Tower Cycles of Concentration	10	Feedwater Flow (lb/hr)	570,604
Evap Cooler Cycles of Concentration	2	Feedwater Flow (gpm)	1140
Condensate Polisher Flow (% FW flow)	50%	Makeup Flow (lb/hr)	959,559
Blowdown quench (% of HRSG BD)	200%	Makeup Flow (gpm)	1918
Condensate Polisher Regeneration Loss	1%	Evaporation Loss Flow (lb/hr)	767,640
Moisture entrained in solids (%product)	2%	Evaporation Loss Flow (gpm)	1534
Wash down Water (1 hose average)	20	Drift Loss Flow (lb/hr)	14,733.7
		Drift Loss Flow (gpm)	29
		Evap Cooler makeup (lb/hr)	24,686
		Evap Cooler makeup (gpm)	49

* All flowrates shown are in gallons per minute unless otherwise noted.

FIGURE 2.1-5BR
WATER BALANCE DIAGRAM, PEAK OPERATIONS
LODI ENERGY CENTER - SUPPLEMENT D
LODI, CALIFORNIA

Source: Worley Parsons LTD, 06-16-09

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2.1.10.1 Water Requirements

On an annual average basis, recycled water use ~~would~~ will be about 1,281 gallons per minute~~856 gallons per minute~~ (gpm) or 2,066 acre-feet per year (afy),~~1,380 acre-feet per year (afy),~~ assuming full-time operation at 8,760 hours per year (Table 2.1-2). Water supply reliability is ensured by the WPCF's recycled water storage capabilities. There will be between 7 and 10 cycles of concentration of the reclaimed water through the cooling system before being discharged to the UIW.~~Water used for makeup in the circulating water system will be treated using a cold lime softener and a microfiltration unit before being fed into the cooling tower collection basin. The micro-filtration feed water storage tank and the micro-filtration product water storage tank will provide approximately 2 hours of operational storage in the event there is a disruption in the supply. Water supply reliability is ensured by the WPCF's recycled water storage capabilities. There will be approximately 5 cycles of concentration of the reclaimed water through the cooling system before being discharged to the UIW.~~

TABLE 2.1-2
Estimated Daily and Annual Water Use for LEC Operations, "~~Rapid Response~~Fast Start" ~~GE Energy Frame 7F~~Siemens SGT6-5000F A Natural Gas-fired Turbine Generator

Water Use[a]		Daily Use (gpm)	Maximum Daily Use ~~(mgpd)~~	Maximum Annual Use[b] (afy)
Process and cooling water:	Average annual ~~(unfired)~~	1,281~~856~~	1.84 mgpd~~1.23~~	2,066~~1,381~~
	Maximum annual ~~(fired)~~	1,810~~1,528~~	2.61 mgpd~~2.2~~	2,920~~2,464~~
Sanitary and domestic water:		5	50 gpd~~50~~	8.1

[a]For the CTG~~GE 7FA~~ values using other operating scenarios, see Appendix 2A.

[b]This assumes full-time operation all year (8,760 hours), which is the maximum operation possible; however, the facility will be periodically taken out of operation for maintenance and will not operate all the time.

2.1.10.2 Water Treatment

Water treatment will be provided on site using reverse osmosis (RO) and demineralizer systems. High-purity water will be stored in an approximately 200,000-gallon demineralized water storage tank. Water quality is described further in Section 5.15, Water Resources.

2.1.10.3 Cooling Tower System

Makeup water from the WPCF will be pre-treated prior to feeding the cooling tower basins to replace water lost from evaporation, drift, and blowdown. A chemical feed system will supply water-conditioning chemicals to the circulating water to minimize corrosion and control the formation of mineral scale and biofouling. Sulfuric acid will be fed into the circulating water system to maintain a target pH to control the scaling tendency of the circulating water. The acid feed equipment will consist of a bulk sulfuric acid storage tank and full-capacity sulfuric acid metering pumps.

To further inhibit scale formation, a polyacrylate solution will be fed into the circulating water system as a sequestering agent in an amount proportional to the circulating water blowdown flow. The scale inhibitor feed equipment will consist of a chemical solution bulk storage tank and two full-capacity scale inhibitor metering pumps.

To prevent biofouling in the circulating water system, sodium hypochlorite will be fed into the system. The hypochlorite feed equipment will consist of a bulk storage tank and two-full-capacity hypochlorite metering pumps. A small storage tank and two full-capacity metering pumps will be provided for the feeding of either stabilized bromine or sodium bromide as alternate biocides.

2.1.11 Emission Control and Monitoring

Air emissions from the combustion of natural gas in the CTG will be controlled using state-of-the-art systems. To ensure that the systems perform correctly, continuous emissions monitoring for NO_x and CO will be performed. Section 5.1, Air Quality, includes additional information on emission control and monitoring.

2.1.11.1 NO_x Emission Control

Selective catalytic reduction will be used to control NO_x concentrations in the exhaust gas emitted to the atmosphere to 2 ppmvd from the gas turbines. ~~and duct burners.~~ The SCR process will use anhydrous ammonia. Ammonia slip, or the concentration of unreacted ammonia in the exiting exhaust gas, will be limited to 10 ppmvd from the catalyst housing. The SCR equipment will include a reactor chamber, catalyst modules, ammonia vaporization and injection system, and monitoring equipment and sensors. The project will make use of the existing ammonia storage system, which consists of an anhydrous ammonia storage tank, spill containment basin, and refilling station with a spill containment basin and sump.

2.1.11.2 Carbon Monoxide

An oxidation catalyst will be used to reduce the CO concentration in the exhaust gas emitted to the atmosphere to 3 ppmvd from the gas turbine.

2.1.11.3 Particulate Emission Control

Particulate emissions will be controlled by the use of best combustion practices; the use of natural gas, which is low in sulfur, as the sole fuel for the CTG; and high-efficiency air inlet filtration; and a lube oil vent coalescer.

2.1.11.4 Continuous Emission Monitoring

Continuous emission monitors will sample, analyze, and record fuel gas flow rate, NO_x and CO concentration levels, and percentage of O_2 or CO_2 in the exhaust gas from the combustion turbine after it has passed through their respective catalysts in the HRSG. The data acquisition and handling system will generate reports of emissions data in accordance with permit requirements and will send alarm signals to the plant supervisory control system when emissions approach or exceed pre-selected limits.

2.1.12 Waste Management

Waste management is the process whereby all wastes produced at LEC are properly collected, treated if necessary, and disposed of. Wastes include process and sanitary wastewater, nonhazardous waste, and hazardous waste, both liquid and solid. Waste management is discussed in more detail in Section-_5.14.

2.1.12.1 Wastewater Collection, Treatment, and Disposal

The primary wastewater collection system will collect process wastewater runoff and stormwater runoff from all of the plant equipment and route it to the oil/water separator and wastewater lift station for testing before discharge to the WPCF. The secondary wastewater collection system will collect sanitary wastewater from sinks, toilets, showers, and other sanitary facilities, and discharge to the WPCF. The water balance diagram, Figure-2.1-5, shows the expected wastewater streams and Table 2.1-1 shows the flow rates for LEC for the annual average and maximum conditions, respectively.

2.1.12.2 Circulating Water System Blowdown

Circulating water system blowdown will consist of the tertiary-treated makeup water from the WPCF and other recovered process wastewater streams from the LEC that have been concentrated by evaporative losses in the cooling tower, along with the chemicals added to the circulating water. The cooling tower concentrates these streams near the mineral solubility limit for the constituents of concern (calcium, silica, and total dissolved solids [TDS]). This concentrated water must then be removed from the cooling tower via blowdown to prevent the formation of mineral scale in heat transfer equipment. The chemicals added to the circulating water control scaling and biofouling of the cooling tower and control corrosion of the circulating water piping and intercooler. Cooling tower blowdown will be directed to an onsite Class I UIW.

2.1.12.3 Plant Drains and Oil/Water Separator

General plant drains will collect containment area washdown, sample drains, and drainage from facility equipment drains. Water from these areas will be collected in a system of floor drains, hub drains, sumps, and piping and routed to the wastewater collection system. Drains that potentially could contain oil or grease will first be routed through an oil/water separator. Water from the plant wastewater collection system will be directed to the WPCF. Wastewater from combustion turbine water washes will be collected in holding tanks or sumps and will be trucked off site for disposal at an approved wastewater disposal facility.

2.1.12.4 Solid Wastes

LEC will produce maintenance and plant wastes typical of power generation operations. Generation plant wastes include oily rags, broken and rusted metal and machine parts, defective or broken electrical materials, empty containers, and other solid wastes, including the typical refuse generated by workers. Solid wastes will be trucked offsite for recycling or disposal (see Section 5.14).

2.1.12.5 Hazardous Wastes

Several methods will be used to properly manage and dispose of hazardous wastes generated by LEC. Waste lubricating oil will be recovered and recycled by a waste oil recycling contractor. Spent lubrication oil filters will be disposed of in a Class I landfill. Spent SCR and oxidation catalysts will be recycled by the supplier or disposed of in accordance with regulatory requirements. Workers will be trained to handle hazardous wastes generated at the site.

Chemical cleaning wastes will consist of alkaline and acid cleaning solutions used during pre-operational chemical cleaning and turbine washwaters. These wastes, which are subject to high metal concentrations, will be temporarily stored on site in portable tanks or sumps, and disposed of off site by the chemical cleaning contractor in accordance with applicable regulatory requirements.

2.1.13 Management of Hazardous Materials

There will be a variety of chemicals stored and used during construction and operation of LEC. The storage, handling, and use of all chemicals will be conducted in accordance with applicable laws, ordinances, regulations, and standards (LORS). Chemicals will be stored in appropriate chemical storage facilities. Bulk chemicals will be stored in storage tanks, and most other chemicals will be stored in returnable delivery containers. Chemical storage and chemical feed areas will be designed to contain leaks and spills. Secondary concrete containment pits and drain piping design will contain a full-tank capacity spill and will prevent chemicals from overflowing the containment area. Each containment area will include a manually operated valve that will allow stormwater to be drained to the plant wastewater system after the water has been tested to ensure no hazardous substances are present. For multiple tanks in the same containment area, the capacity of the largest single tank will determine the volume of the containment area and drain piping. Drain piping for reactive chemicals will be trapped and isolated from other drains to eliminate noxious or toxic vapors.

The existing anhydrous ammonia storage and delivery area currently has both spill containment and ammonia vapor detection equipment.

Safety showers and eyewashes will be provided adjacent to, or in the vicinity of, chemical storage and use areas. Plant personnel will use approved personal protective equipment during chemical spill containment and cleanup activities. Personnel will be properly trained in the handling of these chemicals and instructed in the procedures to follow in case of a chemical spill or accidental release. Adequate supplies of absorbent material will be stored on site for spill cleanup.

A list of the chemicals anticipated to be used at LEC and their storage locations is provided in Section 5.5, Hazardous Materials Handling. This list identifies each chemical by type, intended use, and estimated quantity to be stored onsite.

2.1.14 Fire Protection

The fire protection system will be designed to protect personnel and limit property loss and plant downtime in the event of a fire. Fire water will be supplied by the WPCF and stored in two dedicated ~~the raw water/~~fire water storage tanks at the existing STIG plant. The project will tie into the existing fire system currently in use at the STIG plant. The connection will be sized in accordance with National Fire Protection Association (NFPA) guidelines to provide 2 hours of protection for the onsite worst-case single fire.

~~Fire water from WPCF will be provided to a dedicated underground fire loop piping system or an onsite storage tanks.~~ Both the fire hydrants and the fixed suppression systems will be supplied from the fire water loop which in turn receives water from the on-site storage tanks. Fixed fire suppression systems will be installed at determined fire risk areas as required by NFPA and local code requirements. Sprinkler systems will also be installed in the water treatment building as required by NFPA and local code requirements. The CTG unit will be protected by a carbon dioxide fire protection system. Hand-held fire extinguishers of the appropriate size and rating will be located throughout the facility in accordance with NFPA 10. ~~The cooling tower will include a fire protection sprinkler system or~~ M~~m~~onitor nozzles mounted on fire hydrants located in close proximity to the cooling tower will be employed to provide fire protection for the tower.

Section 5.5, Hazardous Materials Handling, includes additional information for fire and explosion risk, and Section 5.10, Socioeconomics, provides information on local fire protection capability.

2.1.15 Plant Auxiliaries

The following systems will support, protect, and control the generating facility.

2.1.15.1 Lighting

The lighting system provides personnel with illumination for operation under normal conditions and for egress under emergency conditions, and includes emergency lighting to perform manual operations during an outage of the normal power source. The system also provides 120-volt convenience outlets for portable lamps and tools.

2.1.15.2 Grounding

The electrical system is susceptible to ground faults, lightning, and switching surges that result in high voltage that constitute a hazard to site personnel and electrical equipment. The station grounding system provides an adequate path to permit the dissipation of current created by these events.

The station grounding grid will be designed for adequate capacity to dissipate the ground fault current from the ground grid under the most severe conditions in areas of high ground fault current concentration. The grid spacing will be calculated to maintain safe step and touch potentials caused by any type of phase-to-ground fault.

Bare copper conductors and grounding rods will be installed below-grade in a grid pattern. Each junction of the grid will be bonded together by an exothermic weld or other reliable method.

Ground resistivity readings will be used to determine the necessary numbers of ground rods and grid spacing to ensure safe step and touch potentials under severe fault conditions.

Ground conductors will connect the ground grid to building steel, metal tanks, steel structures, mechanical equipment skid frames, and non-energized metallic parts of electrical equipment in accordance with national electrical code (NEC) requirements.

2.1.15.3 Distributed Control System

The DCS provides modulating control, digital control, monitoring, and indicating functions for the plant power block systems.

The DCS will provide the following functions:

- Controlling the STG, CTG, HRSG, and other systems in a coordinated manner
- Controlling the balance-of-plant systems in response to plant demands
- Monitoring controlled plant equipment and process parameters and delivery of this information to plant operators
- Providing control displays (printed logs, LCD video monitors) for signals generated within the system or received from I/O
- Providing consolidated plant process status information through displays presented in a timely and meaningful manner
- Providing alarms for out-of-limit parameters or parameter trends, displaying on alarm video monitors(s), and recording on an alarm log printer
- Providing storage and retrieval of historical data
- Provide an interface with "packaged" equipment (e.g. water treatment system, fuel gas compressors, etc.~~PLCs~~)

The DCS will be a redundant microprocessor-based system and will consist of the following major components:

- PC-based operator consoles with LCD video monitors
- I/O cabinets
- Historical data unit
- Printers
- Integrated processor cabinets for ~~Data links to~~ the combustion turbine and steam turbine control systems

The DCS will have a functionally distributed architecture allowing integration of balance-of-plant equipment that may be controlled locally via a programmable logic controller.

The DCS will include integrated ~~terface with the~~ control systems ~~furnished by the CTG supplier~~ to provide remote control capabilities for both the CTG and STG, as well as data acquisition, annunciation, and historical storage of turbine and generator operating information.

The system will be designed with sufficient redundancy to preclude a single device failure from significantly affecting overall plant control and operation. This also will allow critical control and safety systems to have redundancy of controls, as well as an uninterruptible power source.

As part of the quality control program, daily operator logs will be available for review to determine the status of the operating equipment.

2.1.15.4 Cathodic Protection

The cathodic protection system will be designed to control the electrochemical corrosion of designated metal piping buried in the soil. Depending upon the corrosion potential and the site soils, either passive or impressed current cathodic protection will be provided.

2.1.15.5 Service Air

The service air system will supply compressed air to hose connections for general plant use. Service air headers will be routed to hose connections located at various points throughout the facility.

2.1.15.6 Instrument Air

The instrument air system will provide dry air to pneumatic operators and devices. An instrument air header will be routed to locations within the facility equipment areas and within the water treatment facility where pneumatic operators and devices will be located.

2.1.16 Interconnect to the Electrical Grid

The CTG and the STG will each be connected to a dedicated single, two~~hree~~-winding, three-phase step-up transformer that will be connected to the existing 230-kV switchyard adjacent to the STIG plant via an overhead transmission line. The STG GSU will connect to the overhead transmission line. The connection at the existing switchyard ~~connection~~ will consist of adding a new, single 230kV, SF6 circuit breaker and associated air break disconnect switches to the existing ring bus. ~~position created by the installation of a new single 230-kV, SF6 circuit breaker and associated air break disconnect switches connected in a radial feed scheme.~~ Refer to Section 3.0 for additional information on the switchyard and transmission line.

2.2 Project Construction

Construction of the generating facility, from demolition, site preparation, and grading to commercial operation, is expected to take place from the first quarter of 2010 to the first quarter of 2012, 24 months total. Major milestones are listed in Table 2.2-1

TABLE 2.2-1
LEC Project Schedule Major Milestones

Activity	Date
Begin Construction	First Quarter 2010
Startup and Test	Fourth Quarter 2011
Commercial Operation	First Quarter 2012

There will be an average and peak workforce of approximately 168 and 305 respectively, of construction craft people, supervisory, support, and construction management personnel on site during construction (see Table 5.10-11 in Section 5.10, Socioeconomics).

Typically, construction will be scheduled to occur between 6 a.m. and 11 p.m. on weekdays and Saturdays. Additional hours may be necessary to make up schedule deficiencies, or to complete critical construction activities (e.g., pouring concrete at night during hot weather, working around time-critical shutdowns and constraints). During some construction periods and during the startup phase of the project, some activities will continue 24 hours per day, 7 days per week.

The peak construction site workforce level is expected to last from month 11 through month 18 of the 24-month construction period, with the peak being month 16. Table 2.2-2 provides an estimate of the average and peak construction traffic during the 24-month construction period.

TABLE 2.2-2
Estimated Average and Peak Construction Traffic During Peak Months for the LEC

Vehicle Type	Average Daily Trips During Peak Months	Peak Hourly Trips During Peak Months
Construction Workers	549	276
Deliveries	40	6
Total	589	282

Construction laydown and parking areas will be within existing site boundaries of the WPCF on City-owned property. Four parcels totaling 9.8-acres will be used for both construction and laydown areas, as shown on Figure 2.1-3). Construction access will generally be from North Cord Road. Materials and equipment will be delivered by truck.

2.3 Facility Operation

The LEC facility will be capable of being dispatched throughout the year, and will have annual availability in the general range of 93 to 98 percent. It will be possible for plant availability to exceed 98 percent for a given 12-month period.

The STIG and LEC plants will employ a combined staff of 21 to 23 (16 employees from the current STIG plant, plus an additional 5 to 7 new employees), including plant operation technicians, supervisors, administrative personnel, mechanics, engineers, chemists, and electricians (Table 2.3-1), in rotating shifts. It is expected that the facility will be operated 24 hours per day, 7 days per week.

TABLE 2.3-1
Operating Employees

Classification	Number
Power Plant Technicians	11–12
Lead Power Plant Technicians	5
Operations Supervisor	1–2
Engineer	1
EH&S Coordinator	1
Plant Manager	1

TABLE 2.3-1
Operating Employees

Classification	Number
Administrative Assistant	1
Total	**21–23**

The LEC plant is designed as a base-load facility. Because the combined-cycle configuration will be more efficient than any of the aging gas-fired steam generation facilities in northern California, the LEC plant will be frequently dispatched and will operate on the order of approximately a 76 to 82 percent annual capacity factor. The actual capacity factor in any month or year will depend on weather-related customer demand, load growth, hydroelectric supplies, generating unit retirements and replacements, the level of generating unit and transmission outages, and other factors. The exact operational profile of the plant will be dependent on weather conditions and the power purchaser's economic dispatch decisions.

The facility could be operated in one or all of the following modes:

- **Base Load.** The facility would be operated at maximum continuous output for as many hours per year as dispatched by load dispatch. ~~During high ambient temperature periods when gas turbine output would otherwise decrease, duct firing by steam injection into the combustion turbines may be used to keep plant output at the desired load.~~
- **Load Following.** The facility would be available for full load but operated at less than maximum available output at high load times of the day. The output of the plant would, therefore, be adjusted periodically, either by schedule or automatic generation control, to meet whatever load proved profitable to the power purchaser or necessary by the California Independent System Operator.
- **Full Shutdown.** This would occur if forced by economic conditions, equipment malfunction, fuel supply interruption, transmission line disconnect, or scheduled maintenance of equipment common to all units.

In the unlikely event of a situation that causes a longer-term cessation of operations, security of the facilities will be maintained on a 24-hour basis, and the CEC will be notified. Depending on the length of shutdown, a contingency plan for the temporary cessation of operations may be implemented. Such contingency plan will be in conformance with all applicable LORS and protection of public health and safety, and the environment. The plan, depending on the expected duration of the shutdown, could include draining all chemicals from storage tanks and other equipment and the safe shutdown of all equipment. All wastes will be disposed of according to applicable LORS. If the cessation of operations becomes permanent, the plant will be decommissioned (see Section 2.7, Facility Closure).

2.4 Engineering

In accordance with CEC regulations, this section, together with the engineering appendices and Section 4.0 (Natural Gas Supply), presents information concerning the design and engineering of the LEC facility. The LORS applicable to the engineering of the LEC are provided along with a list of agencies that have jurisdiction, the contact persons within those agencies, and a list of the permits that will be required.

2.4.1 Facility Design

Design and engineering information and data for the following systems are found in the following subsections of this Application for Certification:

- **Power Generation**—See Section 2.1.6.1, Combustion Turbine Generators. Also see Appendix 2B and Section 2.1.15, which describes the various plant auxiliaries.
- **Heat Dissipation**—See Appendix 2B.
- **Cooling Water Supply System**—See Section 2.1.10, Water Supply and Use; and Appendix 2B
- **Air Emission Control System**—See Section 2.1.11, Emission Control and Monitoring, and Section 5.1, Air Quality.
- **Waste Disposal System**—See Section 2.1.12 and Section 5.14, Waste Management.
- **Noise Abatement System**—See Section 5.7, Noise.
- **Switchyards/Transformer Systems**—See Section 2.1.7, Major Electrical Equipment and Systems; Section 2.1.15.2, Grounding; Section 2.1.7.1, AC Power—Transmission; Section 2.1.16, Interconnect to Electrical Grid; Section 3.0, Electric Transmission; and Appendix 2B.
- **Geology**—See Section 5.4, Geologic Hazards and Resources and Appendix 2C Geotechnical Report.

2.4.1.1 Facility Safety Design

The LEC facility will be designed to maximize safe operation. Potential hazards that could affect the facility include earthquake, flood, and fire. Facility operators will be trained in safe operation, maintenance, and emergency response procedures to minimize the risk of personal injury and damage to the plant**.**

2.4.1.2 Natural Hazards

The principal natural hazards associated with the LEC site are earthquakes and floods. ~~Due to the presence of potentially liquefiable soils, the LEC site shall initially be classified as Site Class F for seismic design in accordance with CBC 2007.~~ The Seismic Design Category and final parameters to be used for seismic design must be determined from a site-specific response analysis, which will be undertaken as part of a detailed geotechnical investigation for the site. The site is located in Seismic Risk Zone 4. Structures will be designed to meet the seismic requirements of California Code of Regulations Title 24 and the California

Building Code (CBC) 2007. Section 5.4, Geologic Hazards and Resources, discusses the geological hazards of the area and site and includes a review of potential geologic hazards, seismic ground motions, and the potential for soil liquefaction due to ground shaking. Appendix 2~~C~~B includes the structural seismic design criteria for the buildings and equipment.

According to the Federal Emergency Management Agency (see Section 5.15), the site is located within the 100-year floodplain. Section 5.15, Water Resources, includes additional information on the potential for flooding.

2.4.1.3 Emergency Systems and Safety Precautions

This section discusses the fire protection systems, emergency medical services, and safety precautions to be used by project personnel. Section 5.10, Socioeconomics, includes additional information on area medical services, and Section 5.16, Worker Safety, includes additional information on safety for workers. Appendix 2B contains the design practices and codes applicable to safety design for the project. Compliance with these requirements will minimize project effects on public and employee safety.

2.4.1.4 Fire Protection Systems

The project will rely on both onsite fire protection systems and local fire protection services.

2.4.1.4.1 Onsite Fire Protection Systems

The fire protection systems are designed to protect personnel and limit property loss and plant downtime from fire or explosion. The project will have the following fire protection systems.

Carbon Dioxide and Dry Chemical Fire Protection Systems

These systems protect the combustion turbines and certain accessory equipment compartments from fire. The system will have fire detection sensors in all protected compartments. ~~Actuating one sensor will provide a high-temperature alarm on the combustion turbine control panel. Actuating a second sensor will trip the combustion turbine, turn off ventilation, close ventilation openings, and automatically release the gas and chemical agents.~~ The gas and chemical agents will be discharged at a design concentration adequate to extinguish the fire.

Fire Hydrants/Hose Stations

This system will supplement the plant's fixed fire suppression systems. Water will be supplied from the plant fire water system.

Fire Extinguisher

The plant ~~administrative/control/warehouse/maintenance building,~~ water treatment building, and other structures will be provided with fire protection systems in accordance with NFPA and local codes and regulations. ~~equipped with fixed fire suppression systems and portable fire extinguishers as required by the local fire department.~~

2.4.1.4.2 Local Fire Protection Services

In the event of a major fire, the plant personnel will be able to call upon the San Joaquin County Woodbridge Fire District for assistance. The Hazardous Materials Business Plan (see Section 5.5, Hazardous Materials Handling) for the plant will include all information necessary to allow fire-fighting and other emergency response agencies to plan and implement safe responses to fires, spills, and other emergencies.

2.4.1.5 Personnel Safety Program

The LEC project will operate in compliance with federal and state occupational safety and health program requirements. Compliance with these programs will minimize project effects on employee safety. These programs are described in Section 5.16, Worker Health and Safety.

2.5 Facility Reliability

This section discusses the expected facility availability, equipment redundancy, fuel availability, water availability, and project quality control measures.

2.5.1 Facility Availability

The LEC facility will be designed to operate between about 50 and 100 percent of base load to support dispatch service in response to customer demands for electricity. The plant will be designed for an operating life of 30 years. Reliability and availability projections are based on this operating life. Operation and maintenance procedures will be consistent with industry standard practices to maintain the useful life status of plant components.

The percent of time that the combined-cycle power plant is projected to be operated is defined as the “service factor.” The service factor considers the amount of time that a unit is operating and generating power, whether at full or partial load. The projected service factor for the combined-cycle power block, which considers projected percent of time of operation, differs from the equivalent availability factor (EAF), which considers the projected percent of energy production capacity achievable.

The EAF may be defined as a weighted average of the percent of full energy production capacity achievable. The projected equivalent availability factor for the LEC is estimated to be approximately 88 to 96 percent.

The EAF, which is a weighted average of the percent of energy production capacity achievable, differs from the “availability of a unit,” which is the percent of time that a unit is available for operation, whether at full load, partial load, or standby.

2.5.2 Redundancy of Critical Components

The following subsections identify equipment redundancy as it applies to project availability. Specifically, redundancy in the combined-cycle power block and in the balance-of-plant systems that serve it is described. The combined-cycle power block will be served by the following balance-of-plant systems: fuel supply system, DCS, boiler feedwater system, condensate system, demineralized water system, power cycle makeup and storage, circulating water system, open-cycle cooling water system, and compressed air system. Major equipment redundancy is summarized in Table 2.5-1.

TABLE 2.5-1
Major Equipment Redundancy

Description	Number	Note
Combined-cycle CTG and HRSG	One train	Steam turbine bypass system allows CTG train to operate at base load with the steam turbine out of service
STG	One	See note above pertaining to CTG and HRSG
HRSG feedwater pumps	Two	Each has 100 percent capacity for unfired operation
Condensate pumps	Three – 50 percent capacity	
Condenser	One	Condenser must be in operation for plant to operate, however, it will include divided waterboxes
Circulating water pumps	Two – ~~50~~ 100 percent capacity	Steam turbine may continue to operate at a higher backpressure with one of two circulating water pumps out of service
Cooling tower	One	Cooling tower is a 7-cell mechanical draft design
Natural Gas Compressors	Two – 100 percent capacity	

2.5.2.1 Combined-Cycle Power Block

One combustion turbine/HRSG power generation train is designed for the LEC combined-cycle power block. The combustion turbine will provide approximately ~~60~~ 66 percent of the total ~~unfired~~ combined-cycle power block output. The heat input from the exhaust gas from the combustion turbine will be used in the steam generation system to produce steam. ~~Heat input to the HRSG can be supplemented by firing the HRSG duct burners, which will increase steam flow from the HRSG.~~ Thermal energy in the steam from the steam generation system will be converted to mechanical energy and then to electrical energy in the STG subsystem. The expanded steam from the steam turbine will be condensed and recycled to the feedwater system. Power from the STG subsystem will contribute approximately ~~40~~ 33 percent of the total ~~unfired~~ combined-cycle power block output. The combined-cycle power block comprises the major components described below.

2.5.2.2 CTG Subsystems

The combustion turbine subsystems will include the combustion turbine, inlet air filtration, evaporative cooling, water wash injection, generator and excitation systems, and turbine control and instrumentation. The combustion turbine will produce thermal energy through the combustion of natural gas. The thermal energy will be converted into mechanical energy through rotation of the combustion turbine, which drives the compressor and generator. Exhaust gas from the combustion turbine will be used to produce steam in the associated HRSG. The CTG generator will be totally enclosed, ~~hydrogen cooled~~water to air cooled~~r~~(TEWAC). The generator excitation system will be a solid-state static system.

Combustion turbine control and instrumentation (interfaced with the DCS) will cover the turbine governing system, the protective system, and the sequence logic.

2.5.2.3 HRSG Subsystems

The steam generation system will consist of the HRSG and blowdown systems. The HRSG system will provide for the transfer of heat from the exhaust gas of the combustion turbine ~~and from the supplemental combustion of natural gas in the HRSG duct burner~~ for the production of steam. This heat transfer will produce steam at the pressures and temperatures required by the steam turbine. The HRSG system will consist of ductwork, heat transfer sections, ~~duct burners,~~ an SCR system, and an oxidation catalyst module, as well as safety and auto-relief valves and processing of continuous blowdown drains.

2.5.2.4 STG Subsystems

The steam turbine will convert the thermal energy to mechanical energy to drive the STG shaft to produce electrical energy in the generator. The basic subsystems will include the steam turbine and auxiliary systems, turbine lubrication oil system, and generator/exciter system. The steam turbine's generator will be a totally enclosed, water-to-air cooled (TEWAC) generator. ~~and hydrogen-cooled.~~

2.5.2.5 Plant Distributed Control System

The DCS will be a redundant microprocessor-based system and will have a functionally distributed architecture comprising a group of similar redundant processing units; these units will be linked to a group of operator consoles and an engineer work station by redundant data highways. Each processor will be programmed to perform specific dedicated tasks for control information, data acquisition, annunciation, and historical purposes. Since they will be redundant, no single processor failure can cause or prevent a unit trip.

The DCS will be fully integrated ~~interface~~ with the control systems furnished by the combustion turbine, steam turbine, and HRSG, ~~and fuel gas compressors~~ suppliers to provide remote control capabilities, as well as data acquisition, annunciation, and historical storage of turbine and generator operating information. The DCS will also be networked with those packaged control systems that are typically supplied with the fuel gas compressors, water treatment systems, continuous emissions monitoring system, etc. to provide full control and/or monitoring of those packaged systems.

The system will be designed with enough redundancy to preclude a single device failure from significantly affecting overall plant control and operation. Consideration will be given to the action performed by the control and safety devices in the event of control circuit failure. Controls and controlled devices will move to the safest operating condition upon failure.

Plant operation will be controlled from the operator panel in the control room at the STIG plant. The operator panel will consist of individual CRT/keyboard consoles and one engineering workstation. Each CRT/keyboard console will be an independent electronic package so that failure of a single package will not disable more than one CRT/keyboard. An engineering workstation will allow the control system operator interface to be revised by authorized personnel.

2.5.2.6 Boiler Feedwater System

The boiler feedwater system will transfer feedwater from the LP steam drum to the HP and IP sections of the HRSG. The system will consist of two 100-percent-capacity pumps for supplying the HRSG. Each pump will be multistage, horizontal, and motor-driven and will include regulating control valves, minimum flow recirculation control, and other associated pipes and valves. LP system will receive feedwater directly from the LP economizer using the pressure supplied by the condensate pumps.

2.5.2.7 Condensate System

The condensate system will provide a flow path from the condenser hotwell to the HRSG LP economizers. The condensate system will include three, 50-percent-capacity, multistage, vertical, motor-driven condensate pumps.

2.5.2.8 Demineralized Water System

The demineralized water system will be used for cycle makeup, CTG wash water and chemical cleaning operations. It will include a two-pass reverse osmosis system followed by an electro-deionization system which feeds a demineralized water storage tank. The product water from the first pass RO will be used for CTG evaporative cooler makeup.

2.5.2.9 Power Cycle Makeup and Storage

The power cycle makeup and storage subsystem provides demineralized water storage and pumping capabilities to supply high-purity water for system cycle makeup, water wash, and chemical cleaning operations. The major components of the system are two full-capacity, horizontal, centrifugal, cycle makeup water pumps.

2.5.2.10 Circulating Water System

The circulating water system provides cooling water to condense steam turbine exhaust and steam turbine bypass steam. In addition, the system supplies cooling water to the various equipment coolers, such as lube oil coolers, throughout the plant via the auxiliary cooling water system. Major components of this subsystem are two~~hree~~ 100~~50~~-percent capacity, vertical, motor-driven circulating water pumps and associated pipes and valves.

2.5.2.11 Compressed Air System

The compressed air system will be designed to supply service and instrument air for the facility. Dry, oil-free instrument air will be provided for pneumatic operators and devices throughout the plant. Compressed service air will be provided to appropriate areas of the plant as utility stations consisting of a ball valve and quick-disconnect fittings.

The instrument air system will be given demand priority over the service air system. A pressure control valve will be set at approximately 60 pounds per square inch (psi) to cut off the air supply to the service air header once the system pressure falls below 60 psi.

Two 100-percent-capacity, water-cooled, oil free, rotary screw package air compressors will supply compressed air to the service and instrument air systems.

2.5.3 Fuel Availability

Fuel will be delivered via a new 2.5-mile-long natural gas pipeline that will connect into PG&E's Line #108 east of the project site (see Section 4.0). PG&E has confirmed that its system has enough capacity to supply the LEC from this location. A will serve letter from PG&E is included as Appendix 2E.

2.5.4 Water Availability

The LEC will use, on an annual average basis, 1,061~~709~~ afy of recycled water provided by the WPCF for power plant cooling and process water, based on 4,500 operating hours per year. Potable water will be used for drinking, eye washes, safety showers, and service water from a new onsite well.

The availability of water to meet the needs of LEC is discussed in more detail in Section 5.15, Water Resources. A will-serve letter from the City of Lodi is included in Appendix 2D.

2.5.5 Project Quality Control

The LEC's quality control program is summarized in this subsection. The objective of the quality control program is to ensure that all systems and components have the appropriate quality measures applied; whether during design, procurement, fabrication, construction, or operation. The goal of the Quality Control Program is to achieve the desired levels of safety, reliability, availability, operability, constructability, and maintainability for the generation of electricity.

The required quality assurance for a system is obtained by applying controls to various activities, according to the activity being performed. For example, the appropriate controls for design work are checking and review, and the appropriate controls for manufacturing and construction are inspection and testing. Appropriate controls will be applied to each of the various activities for the project.

2.5.5.1 Project Stages

For quality assurance planning purposes, the project activities have been divided into the following ten stages that apply to specific periods during the project:

- **Conceptual Design Criteria.** Activities such as definition of requirements and engineering analyses.
- **Detail Design.** Activities such as the preparation of calculations, drawings, and lists needed to describe, illustrate, or define systems, structures, or components.
- **Procurement Specification Preparation.** Activities necessary to compile and document the contractual, technical, and quality provisions for procurement specifications for plant systems, components, or services.
- **Manufacturers' Control and Surveillance.** Activities necessary to ensure that the manufacturers conform to the provisions of the procurement specifications.
- **Manufacturer Data Review.** Activities required to review manufacturers' drawings, data, instructions, procedures, plans, and other documents to ensure coordination of plant systems and components, and conformance to procurement specifications.

- **Receipt Inspection.** Inspection and review of product at the time of delivery to the construction site.
- **Construction/Installation.** Inspection and review of storage, installation, cleaning, and initial testing of systems or components at the facility.
- **System/Component Testing.** Actual operation of generating facility components in a system in a controlled manner to ensure that the performance of systems and components conform to specified requirements.
- **Integration with Existing Plant.** Once the new plant is nearing the full system testing phase, the ammonia supply tank will be connected to both the STIG plant and the LEC.
- **Plant Operation.** As the project progresses, the design, procurement, fabrication, erection, and checkout of each generating facility system will progress through the nine stages defined above.

2.5.5.2 Quality Control Records

The following quality control records will be maintained for review and reference:

- Project instructions manual
- Design calculations
- Project design manual
- Quality assurance audit reports
- Conformance to construction records drawings
- Procurement specifications (contract issue and change orders)
- Purchase orders and change orders
- Project correspondence

During construction, field activities are accomplished during the last four stages of the project: receipt inspection, construction/installation, system/component testing, and plant operations. The construction contractor will be contractually responsible for performing the work in accordance with the quality requirements specified by contract.

The subcontractors' quality compliance will be surveyed through inspections, audits, and administration of independent testing contracts.

A plant operation and maintenance program, and specific vendor training, typical of a project this size, will be implemented by the LEC to control operation and maintenance quality. A specific program for this project will be defined and implemented during initial plant startup.

2.6 Thermal Efficiency

The maximum gross thermal efficiency that can be expected from a natural gas-fired combined-cycle plant using one combustion turbine unit is approximately 55.5~~6~~ percent on an HHV basis. This level of efficiency is achieved when a facility is base-loaded. Other types of operations, particularly those at less than full gas turbine output, will result in lower efficiencies. The basis of the LEC operations will be system dispatch within California's power generation and transmission system. It is expected that LEC will be primarily operated in load-following or cycling service. The number of startup and shutdown cycles is expected to range between zero and 182 per year.

Plant fuel consumption will depend on the operating profile of the power plant. It is estimated that the range of fuel consumed by the power plant will be from a minimum of near zero British thermal units (Btu) per hour to a maximum of approximately 2,131 M~~2,15905 million~~ Btu per hour (HHV basis) at base load and minimum ambient conditions.

The net annual electrical production of the LEC cannot be accurately forecasted at the present time due to uncertainties in the system load dispatching model and the associated policies. However, due to the efficiency of the plant, its operating characteristics will be as described above. The maximum annual generation possible from the facility is estimated to be approximately 2,582.4~~289~~ gigawatt hours per year.

2.7 Facility Closure

Facility closure can be temporary or permanent. Temporary closure is defined as a shutdown for a period exceeding the time required for normal maintenance, including closure for overhaul or replacement of the combustion turbines. Causes for temporary closure include a disruption in the supply of natural gas or damage to the plant from earthquake, fire, storm, or other natural acts. Permanent closure is defined as a cessation in operations with no intent to restart operations owing to plant age, damage to the plant beyond repair, economic conditions, or other reasons. Section 2.7.1 discusses temporary facility closure; and Section 2.7.2 discusses permanent facility closure.

2.7.1 Temporary Closure

For a temporary facility closure, where there is no release of hazardous materials, security of the facilities will be maintained on a 24-hour basis, and the CEC and other responsible agencies will be notified. Depending on the length of shutdown necessary, a contingency plan for the temporary cessation of operations will be implemented. The contingency plan will be conducted to ensure conformance with all applicable LORS and the protection of public health, safety, and the environment. The plan, depending on the expected duration of the shutdown, may include the draining of all chemicals from storage tanks and other equipment and the safe shutdown of all equipment. All wastes will be disposed of according to applicable LORS, as discussed in Section 5.14.

Where the temporary closure includes damage to the facility, and there is a release or threatened release of regulated substances or other hazardous materials into the environment, procedures will be followed as set forth in a Risk Management Plan and a Hazardous Materials Business Plan to be developed as described in Section 5.5. Procedures will include methods to control releases, notification of applicable authorities and the public, emergency response, and training for plant personnel in responding to and controlling releases of hazardous materials. Once the immediate problem is solved, and the regulated substance/hazardous material release is contained and cleaned up, temporary closure will proceed as described previously for a closure where there is no release of hazardous materials.

2.7.2 Permanent Closure

The planned life of the generation facility is 30 years. However, if the generation facility were still economically viable, it could be operated longer. It is also possible that the facility could become economically noncompetitive earlier than 30 years, forcing early decommissioning. Whenever the facility is permanently closed, the closure procedure will follow a plan that will be developed as described below.

The removal of the facility from service, or decommissioning, may range from "mothballing" to the removal of all equipment and appurtenant facilities, depending on conditions at the time. Because the conditions that would affect the decommissioning decision are largely unknown at this time, these conditions would be presented to the CEC when more information is available and the timing for decommissioning is more imminent.

To ensure that public health and safety and the environment are protected during decommissioning, a decommissioning plan will be submitted to the CEC for approval prior to decommissioning. The plan will discuss the following:

- Proposed decommissioning activities for the facility and all appurtenant facilities constructed as part of the facility
- Conformance of the proposed decommissioning activities to all applicable LORS and local/regional plans
- Activities necessary to restore the site if the plan requires removal of all equipment and appurtenant facilities
- Decommissioning alternatives other than complete restoration
- Associated costs of the proposed decommissioning and the source of funds to pay for the decommissioning

In general, the decommissioning plan for the facility will attempt to maximize the recycling of all facility components. The Applicant will attempt to sell unused chemicals back to the suppliers or other purchasers or users. All equipment containing chemicals will be drained and shut down to ensure public health and safety and to protect the environment. All nonhazardous wastes will be collected and disposed of in appropriate landfills or waste collection facilities. All hazardous wastes will be disposed of according to all applicable LORS. The site will be secured 24 hours per day during the decommissioning activities.

Appendix B
Revised Design Criteria

1.0 DESIGN BASIS

The Project Technical Requirements provide specific criteria for the Lodi Energy Center Project. These criteria are minimum requirements.

1.1 Overall Facility Configuration

The project will be a 1 x 1 combined cycle facility consisting of one (1) combustion turbine generators (CTG), one (1) heat recovery steam generator (HRSG) ~~equipped with duct burners~~, one (1) steam turbine generator (STG) with a multi-cell mechanical draft cooling tower, and associated auxiliary systems and equipment.

The CTG and STG will be located outdoors with water proof enclosures provided by the respective supplier(s).

The combustion turbine generator utilized will be ~~General Electric 7F,~~ Siemens ~~or other acceptable~~ technology.

The CTG ~~and duct burners~~unit will be fueled by pipeline-quality natural gas only. Two, 100% natural gas compressors will be provided for pressure augmentation.

Power will be generated in the CTG and STG and stepped up through individual~~a single~~ two~~three~~ winding generator step up transformers (GSUT) to the utility grid at 230 kV. A ~~low side~~ generator breaker will be installed on the low side of each GSUT which will allow the~~supplied for each of the CT and ST generator. The~~ generators to~~will~~ be synchronized to the grid.~~via this low side generator breaker.~~

The CTG will be equipped with dry low-NOx (DLN) combustors and inlet air evaporative coolers.

The CTG will exhaust to a Heat Recovery Steam G~~g~~enerator (HRSG) which includes an anhydrous ammonia type SCR system~~s~~ for control of NOx ~~and CO control~~. Catalysts for both NOx and CO will be included in the HRSG system for the reduction of harmful air emissions at the stack. One (1) Continuous Emissions Monitoring (CEMs) systems will be provided.

The project will be designed as an outdoor plant with major equipment located outdoors. The following buildings are included.

- Water Treatment Building
- ~~Warehouse Building~~
- ~~Cooling Tower Chemical Feed Building~~

- ~~Power Distribution Centers (PDC)~~
- ~~(1) CEMS building~~

The plant will be designed for an expected reliability of 92-96 percent over a 30-year life.

Site layout and design, including underground utilities, will be done to accommodate future noise barrier walls along with their foundations, to be located at exhaust duct inlet transition, and all four sides of the gas compressor.

1.2 Operating Mode and Basic Philosophy

- Operational flexibility and high reliability are of paramount importance.

- The plant will be designed to run on a continuous basis between maximum plant output and the minimum load at which emissions ~~guarantees~~ limits are met which is ~~typically~~ 50% of the ~~a~~ CTG output. In other words, to be emissions compliant, the CTG will be required to generate at least 50% of the machine capability to be emissions compliant.

- The CTG will be designed to achieve short duration starts. ~~, typically 40-60 minutes from initiation of starting sequence to full load.~~

- The plant will not be designed to generate electricity while isolated from the utility grid. The anticipated number of operating hours per year is about 6800 hrs

- ~~The BOP equipment and systems will be designed to support the start up times listed above.~~

- The plant control system design will be based on a Distributed Control System (DCS) utilizing both discrete I/O as well as dedicated packaged equipment PLCs such as separate PLC's for gas compressors, CEMS, and air compressors.

- The CTG, STG, and other BOP equipment will be operated primarily from a HMI (man-machine interface) work station in the main plant control room located in the administration building.

- The power block will be designed so that it can be started and operated at any load by a single operator.

1.3 Redundancy in Design

Standby components will be provided for key auxiliary components that would cause an electrical production shut down by their failure. The stand by component will be installed and kept in a ready status for immediate service.

Specific Minimum Redundancy Requirements for Equipment:

COMPONENT	NUMBER OF COMPONENTS REQUIRED
Condenser Vacuum Pumps~~Steam Jet Air Ejectors~~	2~~1~~ x 100% Hogger 2x100% Holding Trains
Ammonia Tanks	~~N/A~~ New NH3 delivery system will share existing NH3 storage tank
Ammonia Forwarding Pumps	2 X 100%~~1~~
Auxiliary Boiler and Feed Pump	1 x 100%
Boiler Feedwater Pumps	2 x 100% ~~(based on non-duct fired performance)~~
Closed Cooling Water Pumps	2 x 100%
Closed Cooling Water Heat Exchangers	2 x 100%
Condensate Pumps	3 x 50%
Circulating Water Pumps	2~~3~~ x 10~~5~~0%
Demineralized Water Pumps	3 x 50%
Auxiliary Cooling Water Pump	1 x 100%
Fuel Gas Compressors	2 X 100%
Dew Point Heater (if required)	1 x 100%
Primary Fuel Gas Scrubber/Filter-Separator/Drains Tank Skids	1 x 100%
Final Performance Heater/ KO Drum Skid (by OEM if required)	1 x 100%~~ per CTG~~
Filter-Separator Skids (main and pilot filters) (by OEM)	2 x 50% (main)~~/CTG~~ 2 x 50% (pilot)~~/CTG~~
Diesel Fire Pump	New plant will share existing fire pump~~N/A~~
Electric Fire Pump	Not used~~/A~~

COMPONENT	NUMBER OF COMPONENTS REQUIRED
Jockey Fire Pump	New plant will share existing fire jockey pump~~N/A~~
Air Compressors/Dryers	2 x 100%
Raw~~Service~~ Water Pumps	2~~3~~ x 100~~50~~%
Oil/Water Separator	2~~1~~ x 100%
Sump Pumps	3~~1~~ ~~x~~ (100% Per Sump)
CTG Lubricating Oil Pumps (AC)	2 x 100% (Part of OEM Package)
CTG Lubricating Oil Pump (DC)	1 x 100% (Part of OEM Package)
CTG Lube Oil Coolers	2 x 100% (Part of OEM Package)
Unit Auxiliary Transformers (4160V)	2 x 100%
Load Center Transformers (480V)	2 sets of 2 X 100%
Battery Chargers	2 x 100%
Uninterruptible Power Supply	1 x 100%
Station Battery (CTG comes with its own)	1 x 100% (covers STG, DCS, BOP, etc.)

1.4 Site-Specific Design Conditions

Site Design Data

Location	Lodi, CA
Project Name	NCPA – Lodi Energy Center

Site Conditions

Max Dry Bulb, Deg F (50 yr Extreme; ASHRAE 2005)	112
Max Mean Coincident Wet Bulb	79.4
Min Dry Bulb, Deg F (50 yr Extreme, ASHRAE 2005)	17.5
Min Mean Coincident Wet Bulb, Deg F	16.5
Elevation (feet above mean sea level)	10

Precipitation

Annual Average, in	16.03
Maximum Monthly Average, in	3.21
Minimum Monthly Average, in	0.0
24 hr. Maximum, 100 Year Storm, in	3.7

Wind Loading

Design Code:	California Building Code (CBC-2007)
Basic Wind Speed (3-Sec Wind Gust Speed)	85~~70~~
Occupancy Category (ASCE 7-05, Table 1-1)	III~~3~~
Exposure Category	C
Importance Factor, I (ASCE 7-05, Table 6-1)	1.15

Seismic

Design Code	California Building Code (CBC-2007)
~~Seismic Zone~~	4
Occupancy Category (Table 1613.5 (1) and (2))	III~~3~~
Site Class	F (liquefiable soils)~~C~~
Seismic Design Category (~~Table 1613.5 (1) and (2)~~ASCE 7-05, Table 1-1)	~~Seismic Design Category is assigned to each structure based on its Occupancy Category and the severity of the design earthquake ground motion at the site.~~ TBD by site-specific response analysis in accordance with ASCE 7-05 Section 21.1
Spectral Response Acceleration, 0.2 Second Period, S~~SDS (Table 1613.5 (1) and (2))~~	0.842~~5~~
Spectral Response ~~Modifica~~Acceleration, 1.0 Second Period, S~~ Factor, R (ASCE 7-05, Table 13.6-1)~~	0.29~~2.5~~
Seismic Importance Factor, I (ASCE 7-05, Table 11.5-1)	1.25

1.5 Air Emission Limitations

The plant design is based on being able to meet the proposed emission limits for the CTG/SCR as provided in the Air Quality section of the Application for Certification.

1.6 Fuel Gas

Pipeline-quality natural gas will be provided by PG&E, with site-specific tie in points to be determined. The gas piping from the gas utility interconnection point to the generating equipment will be part of power plant design and construction scope.

1.7 Water Supply

1.7.1 Raw Water Supply

Raw water for each site will be "Title 22" water obtained from the City of Lodi White Slough Water Pollution Control Facility (WPCF) located adjacent to the power plant.

1.7.2 Plant Wastewater

Facility waste water streams from the water treatment, ~~-~~the oily water separator, evaporative cooler, HRSG drum blow downs make are transferred to the cooling tower. Cooling tower blow down is then transferred via pumping systems to a waste water holding tank. From the holding tank the remaining water is then injected into the new waste water injection well.

1.7.3 Stormwater Runoff

By design the storm water will be sent to the WPCF via various sump pumping stations through out the facility.

1.8 Noise Limits

Project far field noise levels will meet local ordinance requirements ~~of 60 dBA at the property line of the facility~~. Equipment noise mitigation features will be accounted for in the plant design as required to meet LORS.

1.9 Subsurface Conditions

It is not expected that hazardous materials will be encountered during site excavation as the site has been primarily used for agriculture. Full subsurface conditions can be found in the Site Geotechnical Report.

1.10 Electrical / Communication Interconnection

1.10.1 Permanent Electric Power Export and Backfeed

The facility will be connected to the electric utility system through a new single high voltage (HV)~~,~~ circuit breaker~~s~~ and disconnect switches to be located in the existing switchyard. A generator breaker will be provided for the CTG and STG adjacent to the associated GSUT. During facility startup and shutdown, the power required for the facility electrical auxiliary systems will be backfed from the utility system through the GSUTs.

1.10.2 Stand-by Electric Power

Stand-by electric power ~~of~~ will be provided from the neighboring STIG plant via a 12kV interconnect.~~.~~

1.10.3 Communications

Telephone and communication links between the facility and utility, the fuel supplier, and other outside parties will be provided by Owner. Appropriate interface will be provided in the final Plant Design.

1.11 Codes, Standards, and Specifications

The building code for the project location is the 2007 version of the California Building Code (CBC).

The following codes, standards, and specifications of U.S. organizations will be consulted to establish a basis for quality and safety in facility design and operation. Systems and equipment will be designed in accordance with the latest edition and addenda in effect at the date of contract execution, unless noted otherwise.

AASHTO	American Association of State Highway and Transportation Official
AFBMA	Anti-Friction Bearing Manufacturers Association
ACI	American Concrete Institute
AMCA	Air Moving and Conditioning Association
AGMA	American Gear Manufacturers Association
AISC	American Institute of Steel Construction
AISI	American Iron and Steel Institute
ANSI	American National Standards Institute
API	American Petroleum Institute (Applicable sections will be referenced)
ASCE	American Society of Civil Engineers
ASHRAE	American Society of Heating, Refrigeration and Air Conditioning Engineers
ASME	American Society of Mechanical Engineers
ASNT	American Society for Nondestructive Testing
ASTM	American Society for Testing and Materials
AWS	American Welding Society
AWWA	American Water Works Association
CBC	California Building Code
CMAA	Crane Manufacturers Association of America
CTI	Cooling Technology Institute
EJMA	Expansion Joint Manufacturing Association
FM	Factory Mutual (Applicable sections will be referenced)
HEI	Heat Exchange Institute
HIS	Hydraulic Institute Standards

IBC	International Building Code
ICEA	Insulated Cable Engineers Association
IEEE	Institute of Electrical and Electronics Engineers
IES	Illuminating Engineering Society of North America
IFC	International Fire Code
ISA	Instrument Society of America
ISO	International Standards Organization
LPC	Lightning Protection Code
MBMA	Metal Building Manufacturers Association
MSS	Manufacturers Standardization Society of Valves and Fittings Industry
NACE	National Association of Corrosion Engineers
NEC	National Electrical Code
NEMA	National Electrical Manufacturers Association
NESC	National Electrical Safety Code
NFPA	National Fire Protection Association
OSHA	Occupational Safety and Health Administration
PFI	Pipe Fabrication Institute
RMA	Rubber Manufacturers Association
SDI	Steel Deck Institute Standards
SJI	Steel Joist Institute Standards
SMACCNA	Steel Metal & Air Conditioning Contractor National Association
SSPC	Society for Protective Coatings
TEMA	Tubular Exchanger Manufacturers Association
TIMA	Thermal Insulation Manufacturers Association
UL	Underwriters Laboratories
UMC	Uniform Mechanical Code
UPC	Uniform Plumbing Code

Design specifications and construction of the Project will also be in accordance with all applicable local, state, and federal laws, including but not limited to those set forth below.

- Comprehensive Environmental Response, Compensation, and Liability Act of 1980
- Clean Air Act and Amendments
- Environmental Protection Agency Regulations
- Federal Aviation Administration Regulations
- Federal Energy Regulatory Commission Regulations
- Federal Power Act
- Noise Control Act of 1972
- Occupational Safety and Health Act
- Occupational Safety and Health Standards
- Resource Conservation and Recovery Act (RCRA)

- Safe Drinking Water Act
- Solid Waste Disposal Act
- Superfund Amendments and Reauthorization Act of 1988
- Toxic Substances Control Act
- Bay Area Air Quality Management District
- California State Water Resources Board

In the event conflicts arise between the codes, standards of practice, specifications or manufacturer recommendations described herein and codes, laws, rules, decrees, regulations, standards, etc., of the locality where the equipment is to be installed, the more stringent code will apply

1.12 Banned Materials

No materials or products containing the following materials are allowed in the project:

- Asbestos
- PCB's
- Hexavalent Chrome
- Mercury (liquid) (Exception: A limited number of mercury tube level switches may be supplied)

END OF SECTION

2.0 CIVIL/STRUCTURAL DESIGN CRITERIA

This section describes the civil, structural, and architectural design basis for the facility's structures, and general civil work. All civil/structural work will be designed in accordance with applicable codes, industry standards, and local, state, and federal regulations.

2.1 Facility Description

The plant complex will consist of one (1) CTG, one (1) HRSG, an STG, cooling tower, water treatment buildings, transformers, high voltage equipment, BOP equipment, power distribution centers, water treatment area, miscellaneous enclosures, utility racks, and access platforms.

The CTG and STG will not be enclosed in a building. Grading of the finished site will be as indicated on the plant grading and drainage drawings. The project will include a perimeter fence around the site. Main access to and from the site will be by the paved main entrance road.

2.1.1 Plant Layout and Access

The facility will be laid out to accommodate the spaces required to service equipment as well as to maintain and operate the plant. Access aisles and clearance will be provided for safe operation, maintenance, inspection, and equipment removal. Provisions will be made for personnel walkways including, doors, stairs, landings, ladders, and other approved access means.

Personnel and plant maintenance equipment access to plant equipment, piping and their related features will include the following:

- In plant equipment areas, personnel access aisles for operation and maintenance activities will nominally be 4'-0" wide and 7'-6" high.
- The plant will be subdivided into separate fire areas as determined by a Fire Design Mitigation Plan for the purpose of limiting the spread of fire, protecting personnel, and limiting the resultant consequential damage to the plant. Fire areas will be separated from each other by fire barriers, spatial separation, or other approved means.
- The plant will be arranged to facilitate the economic performance of maintenance activities with appropriate use of:
    - Mobile Cranes
    - Forklifts
    - Monorails
- Adequate clear space will be provided above equipment to ensure that foundation bolts or other devices do not obstruct removal.
- Plant fire protection and life safety features will be considered in the plant layout and be designed in accordance with local codes, permits, and insurance requirements.

- Location of natural gas relief valves, any potential chemical releases, and significant heat rejection to ambient air will be separated from CTG and generator air intakes.

2.2 Sitework

Clearing, excavation, backfill, and grading will be performed as required to construct the facility and achieve finished site grades as described in this section.

2.2.1 Site Clearing

The site will be cleared of trees, shrubs, and vegetation to the extent necessary to construct the facility. Provisions for special features (i.e., trees, monuments, or other items) that are to remain and be protected during construction shall be made.

2.2.2 Excavation

Excavation work will consist of the removal of earth, sand, gravel, vegetation, organic matter, rock, boulders, and debris to the lines and grades necessary for construction.

Materials suitable for backfill will be stockpiled at designated locations using proper erosion protection methods. Disposal of any excess uncontaminated backfill material will be to a designated landfill area.

Dewatering of excavations will be done if and when necessary to support construction activities.

2.2.3 Backfilling

Backfilling will be done in uniform layers of specified thickness. Soil in each layer will be properly moistened to obtain its specified density. To verify compaction, representative field density and moisture-content tests will be taken during compaction.

Structural fill supporting foundations and other critical structures, and general site fill will be compacted in accordance with the criteria specified by the Geotechnical Investigation Report.

2.2.4 Grading

Site grading design will comply with applicable land development regulations. Graded areas will be smooth, compacted, free from irregular surface changes, and sloped to drain. Final earth grade adjacent to equipment and buildings will be below finished floor elevations and will be sloped away from foundations as necessary to maintain proper drainage.

Prior to any further construction all graded areas under roadways, foundations, or other supportive areas will have a compacted subgrade consisting of at least the top 6 inches scarified and compacted to 95% of the maximum density based on the modified proctor test (ASTM D-1557) density. Backfill for all embankments, non-supportive and unpaved areas will be compacted to at least 90% of the maximum density based on the modified proctor test (ASTM D-1557) in 6-inch lifts, except trench fill and fill beneath roads will be compacted to 95% of the maximum density based on the modified proctor test (ASTM D-1557).

2.2.5 Erosion Control

During project construction, erosion and sediment control measures will be implemented by the Contractor to prevent sediment-laden runoff from leaving the site. An Erosion and Sediment Control Plan will be developed in conjunction with the Stormwater Management Plan developed for the construction phase of the project. The plan will include the incorporation of silt fencing, straw bale dikes, storm inlet protection, swales, piping, and other measures to promote sediment and erosion control.

2.2.6 Stormwater Management

A Stormwater Management Plan will be developed for the final stabilized site. The intent of the stormwater management plan will be to preserve the existing pre-development drainage patterns to the extent possible. The plan will include a stormwater collection system consisting of all or some of the following elements: ~~detention/retention pond,~~ swales, ditches, culverts, catch basins, and piping.

2.2.7 Roads and Parking

Asphalt site roads and parking will be provided for access, operation and maintenance as shown on the Site General Arrangement drawing. Alternative access, if required by local regulations, will be provided as shown on the General Arrangement drawing.

2.2.8 Site Area Paving

Areas within the power block will be surfaced with concrete or gravel as shown on the General Arrangement drawing. All roads will be paved with asphalt unless specifically shown otherwise on the General Arrangement drawing. Asphalt will be a minimum of 4 inches thick and will be placed in no less than 2 lifts. A minimum of 6 inches of 1.5 inch clean, uniformly graded, crushed stone over a geotextile fabric will be used in areas so designated on the General Arrangement drawing. **Local conditions may warrant the crushed stone layer to be thicker than 6", but in no case will it be greater than 10 inches.** Concrete aprons shown in the crane lift areas of the combustion turbines will be designed to support the crane loads during maintenance activities.

Site roads will be provided that conform to the following:

- Operating speed of 10 miles per hour.
- Minimum road width of 20 feet, with 2-foot shoulders.

- Minimum radius of curvature of 50 feet (centerline) unless restricted.
- AASHTO HS-20-44 loading conditions (minimum requirement).
- Maximum longitudinal slope of 5 percent (except as required for short distances for site entrance and exit roads in which case 8% will not be exceeded).
- Maximum transverse gradient of 2 percent.
- The road to the CT Generator from the plant loop road will be flat (0% slope) for a minimum distance of 70 feet from the face of the generator.

2.2.9 Wetlands Protection

Wetlands will be protected during construction as required and to comply with requirements specified by any laws, codes, and permits.

2.2.10 Landscaping and Fencing

~~Landscape design is currently not in the scope of WorleyParsons.~~ If the Conditions of Certification require landscaping~~e~~, a detailed landscaping plan including~~this will be provided by NCPA. WorleyParsons will coordinate a location for an irrigation connection only if requested by NCPA. A required detailed landscape design,~~ fine grading, furnishing and placement of trees, shrubbery, and/or grass, will be prepared by others.~~NCPA.~~ Any embankment area around the perimeter of the power block and any unpaved areas on site will be gravel.

Any offsite area that is disturbed during construction will be hydro-seeded and restored to the original contours.

A single chain-link fence around the site boundary, with a single 24-foot-wide automatic slide main gate, with a keypad for vehicle use, located at the main entrance will be provided. One manually operated vehicle gate located at another access point around the site will also be provided if an additional vehicle entrance is shown on the Site General Arrangement. The centerline of fence will be at least 6” inside of the property line to assure construction on Owner’s property.

2.3 Civil/Structural Design Requirements

2.3.1 Geotechnical Report

The project equipment foundations will be designed to the meet the requirements of the Geotechnical Report that was prepared during the plant development.

2.3.2 Codes and Standards

The governing building code, CBC2007 and local/state-building codes will be incorporated into the design of buildings and structures. Steel structures will be designed in accordance with the design specifications for structural steel buildings published by the

American Institute of Steel Construction (AISC). Reinforced concrete structures will be designed in accordance with the design requirements for concrete buildings and structures published by the American Concrete Institute (ACI).

Allowable variances and applicable local code interpretations will be established before project commencement.

Additionally all plant areas and structures will be designed and configured to meet OSHA requirements contained in Part 1910 of the U.S. Code of Federal Regulations.

2.3.3 Combustion Turbine Support Structure

The combustion turbine support foundation will be designed in accordance with the manufacturer's recommendations and the Geotechnical Report. Both static and dynamic loading criteria set forth by the manufacturer will be considered. Site specific seismic and wind conditions will be reviewed and compared to the seismic and wind conditions that govern the manufacturer's loading criteria. In general, the structure will be a reinforced concrete mat foundation to support the equipment anchorages.

2.3.4 HRSG Structure

The HRSG structure and related equipment will be supported on reinforced concrete mat foundations. The detailed foundation design will be based on the final Geotechnical Report.

The HRSGs and self-supported steel stacks and platforms will be supported by a reinforced concrete foundation. If required by the final Geotechnical Report, precast concrete piles or other equally suitable pile design will be utilized.

2.3.5 Tank Foundations

The cylindrical vertical tanks will be supported on suitable foundations consisting of a ring-wall foundation or a mat foundation depending on the size of the tank. ~~only if required by the final Geotechnical Report.~~

2.3.6 Transformer Foundations and Protection

Transformer foundations will be designed and constructed in accordance with the requirements of NFPA, local codes and regulations, and manufacturer's recommendations.

Spill containment will be provided for the generator step-up transformers and unit auxiliary transformers, and will be topped with galvanized steel grating. Reinforced concrete retention pits, with a low point sump, will be provided for the transformers and will be sized to contain at least the full oil volume of the transformer. Transformer firewalls will be provided between oil-filled transformers and adjacent structures and equipment as required by the National Electrical Safety Code. The walls will be constructed of reinforced concrete. The transformer pits will have a manually operated outlet valve and drain line routed to the oily water separator. The valve will be a PIV type, but of a different color than fire system PIVs to provide needed differentiation.

Smaller (oil volume < 500gals) oil filled transformers, if used, will be located in bermed areas to facilitate containment of any oil. The bermed area will be of sufficient volume to contain 110% of the transformer oil volume. The height of each berm will be limited to 8 inches above final grade. However, the actual berm depth will be determined during detailed design. A valved drain will be located in the berm wall to allow drainage of rain and ground water from the bermed area. The drain will lead to the OWS sump.

2.3.7 Spill Containment Structures

Spill containment structures will be provided for any chemical injection skid and chemical storage areas including the ammonia storage tank. Chemical injection and storage areas will have local containment designs without means for drains to external sumps, however these will include a sump area. Spill containment at the chemical unloading areas will be provided to contain small spills at hose connection points.

Containment areas will be adequate for the particular fluids being contained, and provide retainage capacity for 110% of the maximum storage. The ammonia truck unloading area is bermed to contain any spills that may occur during filling of the ammonia tank.

A berm (for containment) will enclose the area comprising the CT auxiliary skid. The containment design will include a sump and drain line to the Oil/Water separator.

2.3.8 Loads and Load Combinations

2.3.8.1 Dead Loads

Dead loads will consist of the weight of all permanent construction including, but not limited to, fixed equipment, framing, piping, floors, walls, roofs, partitions, stairs, ductwork, cable tray, and any other structures, contents of tanks, bins, etc.

2.3.8.2 Live Load

Live load is the load superimposed by facility use. It does not include wind load, snow load, earthquake load, or dead load. The minimum live load design basis will be as follows:

- Platforms and walkways
  - Uniform Load, 60 pounds per square foot
  - Concentrated Load, 1,000 pounds on support beams
- Stairs
  - Uniform Load, 100 pounds per square foot
  - Concentrated Load, 1,000 pounds on support beams

- Equipment and piping (other than dead load)
- Supports for equipment and members to which supports are attached will, as a minimum, be designed for the following load cases:
  - Normal operating loads of equipment (excess over dead load)
  - Test loads of equipment and piping (excess over dead load).
  - Thermal force caused by thermal expansion of equipment and piping under all operating conditions.

2.3.8.3 Dynamic loads

These loads will be considered and applied in accordance with the manufacturer's specifications, criteria, or recommendations, and industry standards. Rotating parts will be considered as a vibrating mass.

2.3.8.4 Vehicle loads

Underground piping, conduits, trenches, sumps, and foundations accessible to truck traffic will be designed for HS-20-44 truck wheel loads per the AASHTO Standard Specification for Highway Bridges.

2.3.8.5 Seismic loads

All equipment will be designed to withstand the seismic loading requirement specified in the governing building code for the seismic zone rating of the project site.

In addition, equipment anchorages and supports will be designed to prevent overturning, displacement and dislocation in accordance with governing building code requirements. Piping, cable tray and ductwork will be investigated to determine if stops or other restraints are required.

2.3.8.6 Wind Loads

Wind pressures and shape factors will be applied to all system components and exposed equipment in accordance with governing building code.

Allowances will not be made for the effect of shielding by other structures.

The overturning moment calculated from wind pressure will not exceed two thirds of the dead load resisting moment. The uplifting forces calculated from the wind pressure will not exceed two-thirds of the resisting dead loads and adequate structure-foundation ties will be designed to resist wind forces.

2.3.8.7 Other Loads

Other expected loads (water hammer, dynamic loads from operating equipment, system modulation, etc.) required to predict the response of structures will be considered where appropriate.

Proper load combinations will be used for structural steel and reinforced concrete to comply with applicable codes and standards and with vendor requirements.

2.3.9 Structural Steel

Structural steel will conform to ASTM A 36, ASTM A 992, ASTM A 572 Grade 50, or other materials as required and accepted by AISC, and will be detailed and fabricated in accordance with the AISC Code of Standard Practice and the AISC Specification for Structural Steel Buildings.

High-strength bolts will conform to ASTM A 325 or ASTM A 490. Other bolts will conform to ASTM A 307, Grade A. All bolts will be resistant to rusting for a minimum of 30 years.

Nonheaded anchor bolts will conform to ASTM A 1554 Grade 36, unless higher strength bolting materials are required by design. Exterior exposed anchor bolts that are not high-grade fine thread will be hot dipped galvanized.

Welded structural members will meet the requirements of AWS D1.1.

All outdoor structural steel will be hot-dipped galvanized. Galvanizing will be in accordance with the requirements of ASTM A 123, ASTM A 153, and/or ASTM A 653. Galvanized nuts and bolts will conform to ASTM B 695.

2.3.10 Steel Grating and Steel Grating Stair Treads

The steel to be used for grating and grating treads will conform to either ASTM A 36 or ASTM A 570.

Stair treads will have non-slip abrasive nosings. The treads will have end plates for attaching to stringers.

Grating will be rectangular and consist of welded steel construction. Grating will be hot-dipped galvanized after fabrication in accordance with ASTM A 123. All grating ends and openings larger than 8” will be banded. Grating in the areas subject to chemical attack will be fiberglass for walking surfaces, and cast or ductile iron with epoxy coated imbeds for trench grating (i.e. ABT Trench Systems).

Floor or platform openings around the exhaust duct, pressure vessels, piping, and equipment necessitated by expansion and movement requirements will be protected in accordance with OSHA standards, as applicable. One such requirement is that the largest allowable gap will be four (4) inches between the floor or platform opening and the structure.

2.3.11 Stairs and Ladders

Stairs will be provided between varying elevations. Vertical ladders may only be used where personnel access is infrequent.

Safety cages and/or other devices will be provided for fixed ladders as required by applicable codes and regulations. At a minimum, ladders that may expose a person to a fall of greater than twenty (20) feet will have a cage.

Gates will be installed as fall protection to protect all ladder openings. The gates will fall into two categories: a single bar gate and a gate that is equal to a guardrail (i.e. top rail, mid rail and equal strength).

A single bar gate may be used:

For offset platforms between fixed ladders used only for passing through (not a work area).

Caged ladders to a pass through area.

A guardrail equivalent gate is required as follows:

- A work platform that is accessed by a fixed ladder without a cage must be guarded by a guardrail or gate equivalent to a guardrail system so offset that a person cannot walk directly into the opening.
- A work platform this is accessed by a floor opening ladder way must be protected on all sides except that a gate equivalent guardrail system may be used.
- An open sided work platform that is accessed by a caged fixed ladder on the side of the platform, where the ladder's cage is at least as high as the guardrail system protecting the work platform, must have a guardrail equivalent gate.

Stairs, ladders and safety cages will be hot dipped galvanized. Ladder rungs will be of a non-slip design.

2.3.12 Structural Concrete

Concrete will comply with ACI 301 and ASTM C94. Materials will be handled and stored as recommended in ACI 304. Mixes will be formulated to produce durable concrete of the required strength for the anticipated exposure conditions.

Admixtures may be added at the discretion of the Contractor with the consent of the Engineer, provided that qualifying mix designs are made accordingly.

Where concrete is to be placed by pumping, special consideration will be given to the concrete mix to provide workability, quality, and strength required for the pumping operation.

Calcium chloride or admixtures containing calcium chloride will not be used.

2.3.13 Reinforcing Steel

Concrete reinforcing will be deformed bars of intermediate grade, billet steel conforming to ASTM A 615, Grade 60. Welded wire fabric will conform to ASTM A 185.

2.3.14 Concrete Finishing

Permanently exposed vertical concrete surfaces will receive a “smooth form finish” meaning that all tie holes and surface defects will be patched and all fins exceeding 1/8” will be removed.

Horizontal surfaces will be finished as required by the service area, e.g. some horizontal surfaces will be bull floated, others will be floated and then roughened to provide for a non-slip surface.

Concrete surfaces, both vertical and horizontal, that are to receive a protective coating (i.e. containment areas, and chemical treatment areas) will be finished in accordance with the applicable coating manufacturers recommendation.

2.4 Enclosures

2.4.1 General

Construction materials used in enclosures will meet the definition of noncombustible or limited combustible, except roof coverings which should be Class A in accordance with NFPA 256, Standard Methods of Fire Tests of Roof Coverings. Metal roof deck construction, where used, should be “Class 1” or “fire classified.” <u>Particular attention will be focused on sloping floors and adding drains around equipment to preclude any pooling of water.</u>

Enclosure loads will take into consideration added dead load for items including but not limited to cable trays, pipe, and other items hung from the structure.

Two-hour fire barriers will be provided for the following enclosures:

- Power Distribution Centers (PDC)
- ~~Fire Pump Enclosure (if supplied)~~
- Other as required by Code or local fire authority.

2.4.2 Power Distribution Centers (PDCs)

The electrical switchgear, MCCs, DCS remote I/O panels, metering, protective relaying, batteries and other miscellaneous equipment will be housed in single-story, insulated

Power Distribution Centers (PDC). PDCs will be factory assembled. PDCs will have a controlled environment, both heated and cooled. There will be minimum of (2) separate entries into each PDC. Consideration will be given in the PDC layout and construction to facilitate equipment maintenance and replacement

2.4.3 Site Buildings

The following buildings will be erected on the site:

- Water Treatment Building

~~2.5 Warehouse Building~~
~~2.6 Cooling Tower Chemical Feed Building~~

Each building will be a "pre-engineered" building and will be erected on site. The buildings will conform to CBC2007 and ADA requirements. Each building will have dedicated HVAC, lighting and building services such as water and sewer connections as applicable.

The administration building will include office spaces, restroom and locker room facilities and kitchen facilities.

2.6.1 Fire Pumphouse Module (if supplied)

The fire pumphouse module, including a jockey pump and one electric fire water pump will be located adjacent to the fire/service water tank. Suitable access doors will be provided for maintenance of the pumps.

2.6.2 CEMS Enclosures

The CEMS enclosures will be single-story, insulated, pre-fabricated shop-assembled (modular) metal building supported on a reinforced concrete foundation. The enclosures will be located at ground level. The buildings will contain continuous emissions monitoring equipment and other miscellaneous electrical equipment such as lighting panels. The buildings will be provided with HVAC equipment to maintain proper temperature control for the electronic equipment. Door access will be provided for installation and maintenance of equipment.

2.6.2.1 Concrete Masonry

Hollow load bearing or nonload-bearing concrete masonry unit (CMU) partitions may be used as fire boundaries where required by code in accordance with the UL Fire Resistance Directory. CMU's will be either hollow, normal weight, nonload bearing Type I conforming to ASTM C 129, or load-bearing Grade N, Type I conforming to ASTM C 90.4. CMU's will be filled with mortar and will conform to ASTM C 270, Type M. CMU's will be reinforced as required to meet load capacity.

2.6.2.2 Pre-Formed Metal Siding

Exterior siding will be an insulated field-assembled siding system. Exterior face panels will be 24-gauge minimum; interior liner panels will be 24-gauge minimum standard sheets of galvanized steel. Exposed panel surfaces will have the manufacturer's standard baked-on finish.

The wall system will be designed to withstand the specified wind loading, with practical and equally spaced support girts.

Exterior panel surfaces exposed to weather will be oil coated with Hylar/Kynar 500 or equivalent finish. The interior surface of the exterior panels will be finished with the manufacturer's standard baked-on enamel finish.

The siding finish color will be selected from the manufacturer's standard colors to closely match the existing STIG plant colors.~~manufacturer's standard colors~~

Wall insulation will be noncombustible glass fiber or mineral wool to produce a minimum U-factor of 0.08 Btu/hr/ft^2/°F. Insulated metal panels will contain non-combustible insulation or listed as Class 1 or Class A per Factory Mutual Guide or UL listing.

2.6.2.3 Doors, Frames, and Hardware

Exterior personnel doors will be flush, hollow metal on pressed steel doorframes complete with windows, hinges, locksets, closers, weather-stripping, and accessory hardware. Fire doors and frames will conform to NFPA No. 80 for the class of door furnished.

2.7 Painting and Coatings

2.7.1 Equipment Painting

The painting and coatings will be applied by a contractor that is SSPC – QP1 qualified. The Contractor will perform coating or painting of all areas intended for coating or paint application as described below.

The following equipment and structures will be finish painted following installation except those that are indicated as shop finished below:

- Power island equipment; main and unit auxiliary transformers (shop finished)
- All field erected tanks (bolted tanks are shop finished)
- Uninsulated shop fabricated tanks (shop finished)
- Electrical cabinets and panels (shop finished)
- All carbon steel, such as valves, shop coated tanks, electrical junction boxes, etc.
- All uninsulated carbon steel pipes will be primed and final coated.
- Concrete secondary containment surfaces (including over curb edges)

Off the shelf components such as motor control centers, control boxes, motors, fans, valves, hangers, etc. will receive vendor's "Standard Shop Finish". The CTG~~'s~~ and STG will have compatible alkyd enamel finish over supplier standard primer after touch up in the field.

ITEMS NOT PAINTED OR COATED:

- Galvanized
- Aluminum
- Stainless Steel
- Special Alloys
- Machined Surfaces
- Surfaces to be insulated
- Resinous Materials
- Glass
- Ceramic
- Labels and Nameplates
- Interior Structural Steel

Structural and miscellaneous steel, including pipe supports located outdoors, will be hot dipped galvanized. Field touch-up will be performed after erection.

2.7.2 Coating System Applications

Acceptable Materials for Tank Lining and Exterior Coating (Field Applied Coatings)

<u>Interior Lining</u>
Demineralized Water and Reverse Osmosis Tanks (as applicable) will be lined with Plasite 7156 or equal.

<u>Exterior Coating</u>
The exterior of the tanks will be coated with a factory-applied system with an acrylic enamel finish.

Tanks that are lined or coated will have surface preparation and application in accordance with the instructions of the lining manufacturer. All linings will be free from holidays when tested with a low voltage (67.5 v) wet sponge holiday detector such as a Tinker-Rasor Model M-1 Holiday Detector. Lining will be selected based on the liquid that is stored with respect to the tank material. Minimum lining application will be a 2-coat process with a minimum of 4.0 mils lining per coat.

<u>Scheme</u>
Plant Equipment (uninsulated pipes, tanks, etc.) will be painted a non-reflective medium

gray, with the exception that exposed fire system piping will be painted red and exposed natural gas and ammonia piping will be painted yellow.

2.7.3 Signage

Safety signs will be provided and installed throughout the facility in accordance with OSHA guidelines and general industrial practice. Identification for all exits and fire protection equipment will also be provided. Traffic marking and signs will be provided as necessary to assure proper traffic flow, control and safety. All requirements of the Fire Marshall having jurisdiction will be followed.

2.8 Testing

The services of an independent qualified materials testing laboratory will be engaged to sample, test and certify that the following construction work and materials are installed as specified:

- Earthwork materials and compaction
- Asphalt paving compaction
- Concrete slump
- Concrete strength
- Concrete air entrainment
- Grout strength.
- Masonry Grout & Mortar
- Structural Steel Installation

3.0 MECHANICAL DESIGN CRITERIA

This section describes the primary mechanical equipment and systems, their functions, and the criteria upon which their design will be based for the Lodi Energy Center.

Codes and Standards

The design of the mechanical systems and components will be in accordance with the laws and regulations of the federal government, state of California, San Joaquin County ordinances, and industry standards. The current issue or revision of the documents at the time of the filing of this Application for Certification (AFC) will apply, unless otherwise noted. If there are conflicts between the cited documents, the more conservative requirements shall apply.

The following codes and standards are applicable to the mechanical aspects of the power facility.

- California Building ~~Standards~~ Code, 2007~~1~~
- American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code
- ASME/ANSI B31.1 Power Piping Code
- ASME Performance Test Codes
- ASME Standard TDP-1
- American National Standards Institute (ANSI) B16.5, B16.34, and B133.8
- American Boiler Manufacturers Association (ABMA)
- American Gear Manufacturers Association (AGMA)
- Air Moving and Conditioning Association (AMCA)
- American Society for Testing and Materials (ASTM)
- American Society of Heating, Refrigerating, and Air Conditioning Engineers (ASHRAE)
- American Welding Society (AWS)
- Cooling Tower Institute (CTI)
- Heat Exchange Institute (HEI)
- Manufacturing Standardization Society (MSS) of the Valve and Fitting Industry
- National Fire Protection Association (NFPA)
- Hydraulic Institute Standards (HIS)
- Tubular Exchanger Manufacturer's Association (TEMA)

3.1 Combustion Turbine Generator (CTG)

The CTG will be supplied with a metal acoustical enclosure suitable for outdoor installation. The CTG's will use Dry Low NOx combustors to control exhaust gas NOx. The CTG's will also have evaporative coolers installed for performance enhancement capabilities.

The CTG generator will be a~~either~~ totally enclosed, water to air (TEWAC) cooled ~~or hydrogen cooled,~~ direct-drive, 2-pole, 60 Hz synchronous machine.

Mechanical auxiliary systems for the CTG, which are to be supplied as part of the CTG supplier scope, will be as follows:

- Lubricating and hydraulic oil system
- Oil-to-Water lube oil coolers
- Fuel gas system, including fuel gas metering valve
- Inlet air filtration (static filters) system
- Fire protection and detection system for the CTG
- Starter System (Starting Motor and coupling)
- Turning Gear
- Turbine compartment vent fans
- ~~Generator compartment vent fans~~
- Lube oil filtration system
- Online/offline water wash system
- Starting Systems

CTG inlet air conditioning will be accomplished via an evaporative cooling system. The inlet cooling system will be provided by the OEM. The inlet cooling system will be designed to achieve a compressor inlet temperature that is within 2 deg F of the wet bulb temperature. The inlet cooling system will be complete with pumps, nozzles, interconnecting piping, valves, controls, and other equipment necessary to function across typical load and ambient range.

Equipment will be designed for outdoor installation in ambient conditions.

3.2 Steam Turbine Generator (STG)

~~The STG will be supplied with a metal acoustical enclosure suitable for outdoor installation.~~

The generator will be a~~either~~ totally enclosed, water to air (TEWAC) cooled, ~~or a hydrogen cooled,~~ direct-drive, 2-pole, 60 Hz synchronous machine.

Mechanical auxiliary systems for the STG, which are to be supplied as part of the STG supplier scope, will be as follows:

- Lubricating and hydraulic oil system
- Oil-to-Water lube oil coolers
- ~~Fire protection and detection system for the STG~~
- Turning Gear ~~Starter System (Starting Motor and fluid drive for STG)~~
- ~~Turbine compartment vent fans~~

- ~~Generator compartment vent fans~~
- Lube oil filtration system
- Reduction gear for the HP Turbine

Equipment will be designed for outdoor installation.

3.3 Heat Recovery Steam Generators (HRSG's)

3.3.1 HRSG Description

The HRSG will be a~~duct fired,~~ three-pressure, reheat, natural circulation, "Benson"~~drum~~ type with a once through HP section, horizontal gas flow, complete with manual main steam isolation valves, feedwater stop and check valves, relief valves, and a continuous and intermittent blowdown system. The high pressure (HP), intermediate pressure (IP), and low pressure LP sections will each consist of an economizer, evaporator, and superheater section. The reheat section will heat IP steam and exhaust steam from the HP section of the steam turbine for admission into the IP/LP turbine. The HRSGs will be designed and constructed to operate within the maximum exhaust gas flow and temperature ranges of the CTGs. The HRSGs will be designed for outdoor installation. ~~, with full enclosures over the drum areas.~~

The HRSG will be fabricated, assembled, inspected and tested in accordance with Section 1 (Power Boilers) of the ASME Boiler and Pressure Vessel Code. The HRSG external piping will be furnished, installed and tested in accordance with the requirements of ASME B31.1 (Power Piping) and Section 1 of the ASME, Boiler and Pressure Vessel Code.

The HRSG drums and internals will be sized for required steam separation at the predicted HRSG performance conditions for the minimum HRSG drum pressure. In addition, the steam drums will be designed to accommodate surges associated with startup, shutdown and rapid load changes.

Blowdown from the~~each~~ HRSG will be piped to a~~its respective~~ blowdown tank. Quench water to cool blowdown before discharge will be supplied from the raw water system. Rate of quench water flow will be automatically adjusted in accordance with blowdown temperature. The boiler blowdown tank will be located in the boiler blowdown sump.

All topside drains will be routed to grade. The bottom drains will terminate on the side of the HRSG and the valves will be accessible at grade. The drains will be headered together and the header drained into the boiler blowdown sump. Quench water will be provided to the sump from the raw water system. The nitrogen purge connections, one per drum, will terminate at the valve located within three feet of grade. In the event that long-term lay-up is required, plant operations will have to provide a nitrogen trailer with the required connectors, hoses and regulators.

The HRSG reheater section will be designed for "wet" operation during startup and in case of a steam turbine trip.

The~~Each~~ HRSG scope of supply will include an A36 structural carbon steel stack with motorized stack dampers. ~~The internal bottom portion of the breeching and stack (field welds and up ten (10) feet) will be coated and insulated with a "stalastic-type" material (such as Intertherm 228).~~ Externally, the HRSG shall be insulated from the last tube row through the breeching up to the stack damper elevation. In addition, each HRSG scope of supply will include the necessary emissions control equipment (i.e., SCRs and~~/or~~ CO catalysts) as specified in Section 1.

The gas path will be insulated with ceramic fiber blanket to provide a skin temperature of not more than 140°F, and lined with stainless steel (ASTM A-312 grade 309 where temperatures exceed 800°F).

Man-ways will be provided for access to each section of the HRSG between modules. The manways will be provided with a davit, or will be hinged. The size of the opening will be suitable for maintenance expected in that section. ~~, and in no case be less than 24 X 18 inches.~~

Operating areas of the HRSG will be provided with platforms. Exterior platforms, ladders, rails, and structural steel will be ~~hot dip~~ galvanized. ~~Handrails will be fabricated from 1 ½ - inch diameter steel pipe.~~ Penetrations through platform decking 6 inches or greater in diameter will be finished with plate material.

The vent valves, safety relief valves, silencers, and supporting steel frames will be provided by the HRSG supplier. All vent lines will be extended to a safe location (pointing away from any platforms).

Heat tracing and adequate draining of the HRSG in cold weather will be used to prevent freeze-up of the internal piping of the HRSG. Drain lines will be provided after the double block valves, as well as impulse lines from root valves up to and including transmitter blow-offs, and ~~HP,~~ IP, and LP Drum Level control valves. Drain line connections will also be provided on the vent side of the startup vent valve, power relief valve and safety valves. If silencers are provided with drains, the drain will be piped to a drain manifold.

The~~Each~~ HRSG will be provided with sparging steam connections on ~~all three~~ IP & LP drums at the lower downcomer connection. ~~, and additionally, a drum warming connection on the HP drum saturated steam lines.~~

3.3.2 Stack

The stack will be provided with emission sampling ports in accordance with EPA, State, and local regulatory requirements. A platform located at the sampling port elevation will be provided with ladder access, either from grade or from an adjacent HRSG platform. An expanded metal standoff shield will be provided by HRSG supplier to prevent human contact with 140°F or hotter surfaces, unless external insulation is being utilized with a stack damper as described in 3.2.1 above. A davit will be provided by the HRSG supplier. ~~An electric hoist and weatherproof 120 and 208-volt single phase electrical outlets for powering tools and test equipment at the source test platform are to be provided.~~ Aircraft warning lights will not be provided, in accordance with the FAA or the authority that has jurisdiction in the location of the site. Lightning protection will not be required.

3.3.3 Selective Catalytic Reduction System

SCR system will be provided with catalyst modules designed to facilitate eventual replacement. The system will include a monorail and a hoist for loading & removing SCR catalyst blocks.

~~Engineer will ascertain local process safety and site permitting requirements.~~

The HRSG scope of supply will include:

1 Each	Ammonia Injection Skid
1 Each	Ammonia Dilution Vessel
1 Each	Injection Grid
1 Lot	SCR Catalyst
2 Each	Blowers

The existing 12,000 gallon anhydrous ammonia tank will provide at least 9.45 days of supply for normal 1x1 fuel gas operation.

The system will also include ammonia piping to the ammonia injection skid.

HRSG local instrumentation will be provided by HRSG supplier. All transmitters & measurement elements, including flow measurement devices will be furnished and located at a reasonable distance from the measured location.

3.4 Auxiliary Boiler

The auxiliary boiler is to be designed, constructed, and installed in strict accordance with ASME Code Section I, and stamped and registered with the national board.

The auxiliary boiler will be used to maintain the HRSG and STG in a “hot standby” mode at all times, under all operating conditions. This will allow short startup times and will allow the plant to achieve emissions compliance in a much shorter time than if no auxiliary boiler was utilized.

3.5 Fire Protection System

3.5.1 General

NFPA 850 and the applicable fire code will provide the general guidance for the fire protection considerations of the facility. A Fire Mitigation Design Plan will be prepared to detail the site-specific fire protection features of the facility.

The fire prevention and protection design for the facility will be reviewed and must receive approval from the local Fire Marshal and Owner's insurance representative.

Automatic and manual fire protection systems employing detection and extinguishing equipment will be provided at all locations having potential fire hazard due to the presence of combustible materials or where major property damage could result. Yard hydrants and portable extinguishers will provide additional incipient fire extinguishing capability and overall protection throughout the plant site.

The fire protection water supply will be taken from an onsite fire/raw water storage tank and distributed to the site fire protection system via a new underground firewater loop with necessary hydrants. The fire loop will be pressurized by an electric motor driven fire pump with a diesel driven fire pump as a backup. Hose houses will not be installed around the yard since plant-operating personnel will only be trained to extinguish incipient fires and local fire department personnel will only use their own hose.

3.5.2 Fire Protection System

It is expected that the new plant fire protection system will be physically tied into the existing plant's underground firewater piping loop. The advantage to this design is obvious in that the entire site can take advantage of a single set ~~(existing)~~ of fire pumps (existing).

As a minimum, the fire protection system will include:

Area of Building	Standard	Detail
Fire Extinguishers Site Wide	NFPA 10	Use Dry Chemical only if it is best option ~~Wheeled 33 gallon AFFF and 50 pound dry chemical extinguishers in the fuel oil pump, storage, and heating areas.~~

Fire Hose & Standpipe	NFPA 14	Provide for the Warehouse
Fire Water Supply / Distribution Tank Fire Pumps/Controllers Underground piping/loop	 NFPA 22 NFPA 20 NFPA 24	Two~~A~~ existing tanks provided with level monitor at ~~will beprovided at~~ ground level. Existing~~An~~ approved flow meter and piping to the firewater tank ~~will be~~ provided to test each fire pump. Emergency fire department water supply connections should be provided by installing a suction connection at the tank, and a fire hose pumper connection downstream of the fire pump discharge valves. Sectional control valves should be provided so that no more than five hydrants or individual suppression systems would be out of service in the event of a main break.
Fire Hydrants	NFPA 24	Hydrants will be spaced <=300 ft apart around the new plant perimeter

Steam Turbine Generator		
STG Bearings	NFPA 13	Pre-action System w/ Rate-of-Rise for Steam Turbine and Generator Bearings
Lube Oil Reservoir and Piping	NFPA 13	Water Spray System w/ dry pilot actuation system
~~Hydrogen Seal Oil Unit~~	~~NFPA 13~~	~~Water Spray System w/ dry pilot actuation system~~
Enclosed "Under Tabletop" Area	NFPA 13	Water Spray System w/ dry pilot actuation system to protect the "under belly" of the steam turbo-generator and other plant equipment enclosed in the "STG building", beneath the STG tabletop
STG Enclosure "Above Tabletop"	NFPA 13	Water Spray System w/ dry pilot actuation system
Main Steam Stop Valve	N/A	Fyrquel or approved fire resistant hydraulic oil
Combustion Turbine Generator		
Turbine Enclosure	NFPA 850	Provided by OEM
Exhaust Bearing Tunnel	NFPA 17	Provided by OEM
Support buildings/structures	NFPA 2001	Provided by OEM
Mechanical package	NFPA 850	Provided by OEM
Electrical package	NFPA 850	Provided by OEM
HRSG	NFPA 8506	Provided by OEM

Transformers Generator Step-Up Unit Auxiliary (>480V) ~~Auxiliary~~ ~~Other Transformers~~	NFPA 15 NFPA 15	~~Water Spray System w/ dry pilot actuation system for each transformer~~ ~~Water Spray System w/ dry pilot actuation system for each transformer~~ ~~Protection based on oil volume and location~~
Power Distribution Centers (PDC's)	NFPA 72	Smoke detection throughout
Water Treatment Building **Electrical Room**	NFPA 13 NFPA 72	Wet pipe sprinkler (only if justified by combustible loading; generally not required) Smoke detectors
~~**Boiler Feed pump**~~	~~NFPA 13~~	~~Wet pipe sprinkler system~~
Chemical Skids	NFPA 13	Sprinkler system (if required by combustible loading; generally not required)
Cooling Tower Water Treatment Bldg.	N/a	N/a
Other Hazards Fuel Yard Area Ammonia Storage Area Cooling Tower Fan Deck	NFPA 24& 54 NFPA 850	Monitor Nozzle(s) mounted on hydrant(s) Existing anhydrous ammonia storage tank will be provided with a water deluge system and ammonia detectors~~Monitor Nozzle(s) mounted on hydrant(s) with a water spray/fogging system with ammonia detectors~~ Monitor Nozzle(s) mounted on hydrant(s)

3.5.3 Additional Fire Protection Features

Additional features of fire protection/detection include:

– One central fire detection control panel to monitor status of zones, with visual indications, audible alarm, and test provisions; and/or a remotely located fire detection control panel in a location where there is 24/7 manned coverage

- Area fire/smoke detectors where required for automatic suppression systems
- Fire alarm horns (audible throughout the site)
- Manual pull stations
- Interconnecting cabling
- Natural gas and ammonia leak detection

3.6 Compressed Air System

The compressed air system will be designed to supply service and instrument air for the facility. Dry, oil-free instrument air will be provided for pneumatic operators and devices throughout the plant. Compressed service air will be provided to appropriate areas of the plant as utility stations.

The instrument air system will be given demand priority over the service air system. A pressure control valve will be set at approximately 85 psi to cut off the air supply to the service air header once the system pressure falls below that set point

Two (2), 100 percent capacity packaged air-cooled air compressors will supply compressed air to the service and instrument air systems. The control system will be designed to allow either air compressor to become the “lead” and will provide instrument air system pressure indication and a low-pressure alarm. The instrument air system will include two parallel duplex instrument air dryers, a compressed air storage receiver, stainless steel piping, valves, instrumentation and controls.

3.6.1 Instrument/Service Air Requirements

The total instrument air flow capacity is based on the total quantity of air users, capacity of each air user, an average load factor of 25 percent, plus an additional 50 percent margin to account for air leakage. All instrument air will pass through the air dryers. Instrument air will be dried to a dew point of -40 degrees F.

3.6.2 Service Air Requirements

Utility hose stations will be located as necessary throughout the plant to allow all equipment to be accessed via air hose. Each hose station will have with a ball valve, an anti whip valve and a quick disconnect coupling.

3.6.3 Emergency Air Compressor Connection

An emergency air compressor connection consisting will be located in the air header ahead of the compressor discharge air receiver and in a location reachable by a portable air compressor air hose. This connector will be sized for at least the same flow rate as one of the plant air compressors. An oil trap will be supplied at the emergency connection to prevent oil from the emergency air compressor entering the instrument air system.

3.7 Compressed Gas Systems

All compressed gas tanks/cylinders and pressure regulators required to operate and maintain the facility will be provided. All interconnecting piping, valves, instrumentation and controls will be part of design.

3.7.1 Carbon Dioxide

A carbon dioxide system will be provided for fire protection at the CTG and STG.

3.8 Heating, Ventilating, and Air-Conditioning System

The design basis for sizing the system will be as follows:

Design Basis		
Area	Summer	Winter
~~Control Room, Electronics Room, and Office and Lab Areas~~	~~75°F, 50% R.H.~~	~~70°F~~
Battery Room	80°F, 50% R.H.	75°F
~~CEM Bldgs~~	~~80°F, 50% R.H.~~	~~60°F~~
Electrical and Control Equipment Rooms,	80°F, 50% R.H.	50°F
~~Toilet/Locker Areas~~	~~75, 50% R.H.~~	~~70°F (ventilated)~~
All other Areas (incl. Water Treatment~~Turbine~~ building)	100°F (Ventilated)	50°F

The HVAC system will consist of building heating, building ventilation for fresh air makeup and cooling, and air-conditioning as required and will include:

~~Two 100-percent-capacity HVAC systems for the control and electronics rooms and one 100-percent-capacity HVAC system for the balance of the administration building, with miscellaneous piping, ductwork, insulation, dampers, louvers, and controls for an efficient and operable system.~~ Systems will not take suction from areas where fumes might be present (e.g., maintenance shop area) to prevent introduction of irritants and gases such as CO, into administration areas.

- ~~One 100-percent-capacity HVAC unit for the water treatment lab (may be part of other adjacent systems if not remotely located).~~

- Separate redundant exhaust fans for battery room.
- One 100-percent-capacity HVAC unit for the electrical switchgear room, control equipment room, and battery room sections of the water treatment building.
- Ventilation fans and electric or gas radiant heaters for ~~maintenance, warehouse, and~~ water treatment areas.
- Ventilation fans and electric unit heaters for boiler feed pump enclosures (when such enclosures are specified in Section 1).
- Two, 100%~~Multiple~~ HVAC units per PDC (supplied as part of the package)
- ~~Ventilation fans and unit gas heaters for the turbine building and auxiliary boiler building as required~~

For indoor areas not normally occupied, the heating system will be capable of maintaining a nominal indoor temperature of 50°F at the HVAC design outdoor conditions. Heating design will be based on the plant being shut down with no solar warming.

HVAC systems serving typical manned areas~~the control room, maintenance shop offices, lab areas, and administration areas~~ will be designed to provide comfort levels for extended human occupancy. HVAC for other areas will be designed in consideration of equipment and environmental requirements, including dust control. Air velocities in ducts and from louvers and grills will be low enough to prevent unacceptable noise levels in areas where personnel are normally located.

Air-conditioning will include both heating and cooling of the filtered inlet air. Air filters will be housed in a manner that facilitates removal. The filter frames will pass the air being handled through the filter without leakage. Ductwork, filter frames, and fan casings will be constructed of galvanized mild steel sheets stiffened with galvanized mild steel flanges. ~~Ductwork will be furnished and installed per UMC 1997.~~ Duct joints will be leak tight. Grills and louvers will be of adjustable metal construction.

Fans and motors will be mounted on antivibration bases to isolate the units from the building structure. Exposed fan outlets and inlets will be fitted with guards. Wire guards will be specified for belt-driven fans and arranged to enclose the pulleys and belts.

Modules will be ground mounted (for ease of maintenance) in locations where they are least likely to be damaged, cause inconvenient obstruction, or be exposed to gasses or odors.

~~HVAC systems will meet requirements of NFPA 90A, standard for installation of air conditioning and ventilating systems. An air balance will be part of the scope.~~

3.9 Fuel System

3.9.1 Fuel Gas

The fuel gas system treats and delivers fuel gas to equipment at the desired conditions. The scope of the fuel gas system extends from the interface with the utility natural gas connection at the plant property boundary to the gas interfaces for the CTG. The fuel gas system will be designed to accommodate the ~~reciprocating~~ fuel gas compressors and fuel gas requirements of the CTG.

The fuel gas supply system includes 2 x 100% fuel gas compressor packages which will control gas pressure and temperature to CTG manufacturer requirements. Each compressor is sized to provide the total natural gas needed for the~~one~~ CTG unit. The compressor package includes inlet-side scrubber(s) to remove coarse sludge from the incoming gas and~~,~~ discharge coalescing filter(s).~~, and discharge cooler(s).~~ The inlet scrubber and discharge coalescing filters will be located on either the gas compressor package skid or on a separate skid. ~~The discharge cooler will be a separate skid package.~~ The compressor package will include a recycle system to control discharge pressure across all CTG operating conditions.

A regulating station will reduce the utility supply gas pressure to match design conditions at the inlet of the gas compressor. The design will include the capability to increase the setpoint of the regulating station and manually adjust the volume pockets of the gas compressor in order to minimize electric power consumption of the compressor.

The fuel gas system will have provision to bypass the gas compressor for unusual situations where the gas compressor is unavailable and utility line pressure is sufficient to run the CTG. In such bypass situations, the fuel gas must flow through the inlet scrubber and discharge coalescing filter in the gas compressor area.

A duplex filter/coalescer will be located downstream of the gas compressor equipment near the CTG unit. Carbon steel interconnecting piping will be provided from the gas compressor area to the final filter/coalescer. All piping after the final filter/coalescer will be stainless steel. Condensate and other waste drained from the filter/coalescer will be routed to the waste water collection system.

3.10 Lubricating Oil Systems

Lubricating oil systems will be provided with the CTG and STG including all lubricating oil pressure and drain piping, as well as all valves, devices, and controls needed for an operable system. Lube oil pipe will be stainless steel. The CTG and STG lube oil is cooled by an oil to water heat exchanger.

3.11 Cranes/Monorails

Equipment will be arranged to allow maintenance to be performed via mobile crane access to the CTG, STG, and other major equipment. The CTG and STG will include a monorail lifting beam and hoist for turbine removal.

3.12 Pumps

3.12.1 General Service Pumps (200 HP and Smaller)

Pumps will be sized for maximum efficiency at the normal operating point. Pumps will be free from excessive vibration throughout their operating range.

Pumps will operate satisfactorily at various flow rates up to maximum pump output. Pump motors will be sized so the selected pump impeller will not overload the motor at any point on the pump head-capacity curve. Wear rings will be provided as appropriate.

Vent and drain valves will be fitted at high and low points on the pump casing. Pumps rated 25 hp and above typically have a recirculation line for protection. The recirculation line will normally be routed to the source from which the system takes suction. Restriction orifices will be used as appropriate.

Horizontal split-case pumps will allow the removable casing half and impeller to be withdrawn without disturbing any of the process piping or valves. Horizontal end-suction pumps will allow the impeller to be withdrawn without disturbing the motor or discharge piping.

Pumps will have expansion joints between the inlet and outlet side and piping connected to them as required by good engineering practice.
Strainers (startup or permanent) will be installed in the suction piping of horizontal pumps or sets of pumps. The driver will be mounted on an extension of the pump bedplate and will drive the pump through a flexible coupling.

Vertical shaft pumps will be designed to Hydraulic Institute standards and will generally be arranged to work with the pump casing submerged in a sump or tank. The suction branch will be arranged vertically downward and, if required for the service conditions, will be fitted with a strainer. When pumping fresh water or condensate, bearings situated below water level will be water lubricated. Discharge piping and non-return valves will be arranged to facilitate withdrawing the complete shaft and pump casing as a unit by splitting a pipe joint above floor level.

Pumps will have mechanical seals (25,000-hr life if available), if appropriate for the application. In general, major pumps will be specified to have mechanical seals. Pumps with mechanical seals will be arranged to facilitate seal removal. Shaft slingers will be specified to prevent packing gland leakage water from entering bearing housings.

Bearings requiring cooling water will include the necessary pipe work, valves, and strainers.

Couplings and any intermediate shafting will be provided with OSHA approved guards. Bedplates will be of ample proportions and stiffness to withstand the loads likely to be experienced in shipment and service.

3.12.2 Boiler Feed Pumps

Boiler feedwater pumps will provide feedwater consistent with the HRSG design conditions as stipulated in ASME, Section I, Power Boilers, paragraph PG-61. Where there is an intermediate pressure level in the steam generator, and the flow rate of the intermediate level is less than approximately a third of the high-pressure section, the boiler feedwater pump will include an interstage bleed. The interstage bleed will allow a single pump to feed the high pressure as well as the intermediate pressure levels of the HRSG. Where the flow rate of the intermediate level is more than a third of the high-pressure level, separate boiler feed pumps will be provided for the required pressure levels of the HRSG.

~~An interstage bleed type of pump will be provided with one recirculation valve installed on the high-pressure section. Minimum flow measurement will be taken from the high-pressure feedwater flow element. Recirculation flow will be directed to the low-pressure drum. No recirculation valve is required from the bleed section of a pump.~~

The boiler feedwater pump will be equipped ~~with a "T-type" suction strainer (with at least 4 x pipe area) consisting of a 120 mesh enclosed by a permanent 80 mesh strainer. Each boiler feedwater pump will be provided~~ with its own, closed lubrication system. Pump start up will require lubrication system start up before the pump is allowed to start. Pump shaft seals will be mechanical, designed for the proper temperature.

Vibration Probes - Vibration probes will be ~~Bently Nevada Series 3300XL~~ proximity probes.

Vibration Monitoring System - A separately mounted vibration monitor system will be provided to monitor the boiler feed pump and motor probes. Vibration monitors will be Bently Nevada Series 3500 or acceptable equal and one vibration monitor will be provided for each set of two motor/pump sets.

DCS Alarm and Tripping - 4-20mA signals from the 3500/42M proximitor monitors for each boiler feed pump will be wired to the balance of plant DCS system for indication, alarming, and tripping.

The~~Each~~ HRSG will have two 100% boiler feed (very high flow operating cases will require dual pump operation).). The boiler feed pumps will be electrically driven, multistage, centrifugal pumps. ~~with the following:~~

- ~~Heavy-duty baseplate for all components and accessories.~~
- ~~Sleeve bearings and Kingsbury-type thrust bearings with forced oil lubrication.~~

- ~~400 series stainless steel shafts and chromoly cases (API 610 Table H-1 C-6).~~
- ~~The pump system will include the following instrumentation:~~
  - ~~Discharge Pressure~~
  - ~~Discharge Temperature~~
  - ~~Bearing Temperature~~
  - ~~Suction Pressure~~
  - ~~Suction Temperature~~
  - ~~Suction strainer differential pressure (transmitter plus local indication)~~
  - ~~Low NPSH alarm~~
  - ~~Vibration Detection~~

3.12.3 Condensate Pumps

Condensate pumps will be multistage, vertical, open shaft, canned type pumps with the suction nozzle in the discharge head. ~~(T-type head).~~ The condensate pump will be selected specifically for low NPSH service. ~~Pump sizing will assume the available suction pressure at the pump suction nozzle centerline is zero.~~ The condensate pump will be equipped with a suction strainer. Loss through the suction strainer will be accounted for in setting the height of the surface condenser relative to the pump suction nozzle centerline. Condensate pumps will be provided with minimum flow recirculation lines satisfying the pump manufacturer's minimum flow requirements and with consideration for the gland steam condenser and air ejector minimum flow requirements. The pumps will be suitable for parallel operation over their full performance curve. Wetted parts of the pump will be stainless steel.

3.12.4 Circulating Water Pumps

The circulating water pumps will be single stage, vertical, open shaft pumps with single suction impeller design in accordance with HI Standards. Head vs. capacity curves will rise continuously toward shut off head without reversing slope. An auxiliary source of water will be provided for pump shaft bearing lubrication when pumps operate in conditions where line bearings may be dry on start up, or when quality of the pumped water may cause damage to bearings. All wear rings will be fully renewable

Each pump will be provided with a motor operated discharge valve.

Each motor will be provided with a reverse rotation lock device to ensure the motor and pump do not reverse-rotate and cause damage. All wetted components will be suitable for worst-case water quality.

3.12.5 Fire Water Pumps

It is not expected that additional fire pumps will be required beyond what is already installed at the existing plant. However, if new pumps are deemed necessary, a modularized system containing one each FM (Factory Mutual) approved pump of the following types will be provided for the plant fire suppression system. Fire water pumps will be tested in accordance with NFPA requirements.

- Electric Fire Water Pump
- Diesel Fire Water Pump
- Jockey Fire Water Pump

~~3.12.6 Positive Displacement Pumps~~

~~Rotary positive displacement pumps will be either gear or screw type. All rotary positive displacement pumps will be provided with an exterior relief valve to protect the pump and piping upstream from an inadvertently isolated discharge valve.~~

3.13 Storage Tanks

Large outdoor storage tanks will be freeze protected, as required, through the use of insulation and heaters and nozzle insulation and heat tracing.

Overflow connections and drop downs to grade lines will be provided. Maintenance drain connections will be provided for complete tank drainage.

Manholes, where provided, will be at least 24 inches in diameter and hinged to facilitate removal. Storage tanks will have ladders and cleanout doors as required to facilitate access/maintenance. Provisions will be included for proper tank ventilation during internal maintenance. Ladders and platforms will be galvanized and designed in accordance with API and OSHA standards.

Local level indication will be provided with level transmitters for monitoring in the control room and a float system for local monitoring.

Bolted tanks will utilize encapsulated nuts for interior bottom seams and polycapped bolts in sidewalls and deck vapor areas.

Tanks will be designed using the following criteria:

Tank	Quantity	Description	Size in Gallons (see note)
~~Fire/~~Raw Water Storage	1	Carbon Steel Bolted Fab & Erect AWWA D103-97/NFPA 22 with factory applied exterior and interior coating	330,000~~TBD~~
Demineralized Water Storage	1	Carbon Steel Bolted Fab & Erect AWWA D103-97 with factory applied exterior and interior coating	200,000

Tank	Quantity	Description	Size in Gallons (see note)
Water Wash Drain Tank	1	Horizontal, Cylindrical Double Wall Tank, Fiberglass	5,000
Gas Turbine Drains Tank	1	Horizontal, Cylindrical Double Wall Tank, Fiberglass, Integral with Water Wash Drain Tank	500 To be integral with water wash drain tank (divided)
Closed Cooling Water Head Tank	1	Horizontal, Cylindrical Carbon Steel	1,000
Oil/Water Separators	2~~1~~	Double Wall Carbon Steel	500
~~Service Water Tank~~	~~1~~	~~Carbon steel~~	~~15,000~~

3.14 Pressure Vessels

Pressure vessels will be ASME stamped and will include, at minimum, the following features/appurtenances:

Vessel	Quantity	Description	Capacity Gallons
Blowdown Tanks	1	Vertical, Carbon Steel per ASME Section VIII with Stainless Steel Wear Plate	4,000
Compressed Air Receiver	1	Vertical, Carbon Steel per ASME Section VIII	500
Steam Turbine Drain Tank	1	Vertical, Carbon Steel, ASME Section VIII with Stainless Steel Wear Plate	1,000

Pressure vessels will be ASME stamped and will include, at minimum, the following features/appurtenances:

- Process, vent, and drain connections for startup, operation, and maintenance.
- Materials compatible with the fluid being handled.
- A minimum of one manhole and one air ventilation opening (e.g., handhole) where required for maintenance or cleaning access.
- Relief valves in accordance with the applicable codes.

3.15 Heat Exchangers

3.15.1 Heat exchangers will be shell-and-tube or plate type and will be designed in accordance with Tubular Exchanger Manufacturers Association (TEMA) or manufacturer's standards. Fouling factors will be specified in accordance with TEMA. Cooling duty and fluid characteristics will be considered in determining fabrication materials, wall thickness, etc.

3.16 Piping and Piping Supports

Piping will be designed, selected, and fabricated in accordance with the following criteria:

3.16.1 Design Temperature and Pressure

The design pressure and temperature for piping will be consistent with conditions established for the design of the associated system.

The design pressure of a piping system will be the maximum of:

- The set pressure of a relief valve mounted in the line
- The set pressure of a relief valve installed on equipment that is connected to the line, adjusted accordingly to account for static head and friction loss
- If the system has no PSV or can be isolated from a PSV, the maximum pressure upstream equipment can generate (i.e., pump shutoff pressure).
- The maximum sustained pressure that may act on the system plus 25 psi.

The main and process steam piping design pressures will be in accordance with applicable codes. All design pressure values will be rounded up to the next 5-psig increment.

The design temperature of a piping system will be based on:

- The maximum sustained temperature which may act on the system plus 25°F

If a heat exchanger of piece of equipment in which heat is being removed can be taken out of service or bypassed, then the line downstream of that equipment will be designed for the resulting higher temperature.

3.16.2 General Design and Selection Criteria

Piping will be designed in accordance with the requirements of the Code for Pressure Piping, ASME B31.1-Power Piping, and other codes and standards referenced in Section 2, Codes and Standards. Pipe stress analysis will be performed in accordance with ASME B3 1.1. All pipe supports will be suitable to restrain the piping where subjected to external loads as stipulated by the California Building Code – Seismic and Wind Load Criteria. Vents and drains will be provided, as service requires.

Material selection will generally be based on the design temperature and service conditions in accordance with the following:

- Carbon steel piping materials will be specified for design temperatures up to and including 800°F.
- One and one-quarter percent chromium alloy steel piping materials will be specified for design temperatures ranging from 805°F to 950°F. 21/4 percent chromium alloy steel piping may be specified for design temperatures ranging from 955°F to 1100°F, however, 9 percent chromium alloy steel piping will be specified for high pressure steam and hot reheat steam systems which have a design temperature of approximately 1065°F.
- Scale free piping materials such as cleaned carbon steel, stainless steel or non-metallic will be used as follows:

  Piping applications requiring a high degree of cleanliness generally including injection water supply piping after strainers, air compressor inlet piping, miscellaneous lubricating oil system piping, and sampling piping after process isolation valves.

  Lubricating oil piping; carbon steel piping shall be pickled and stainless steel piping shall be swabbed.

  Fiberglass reinforced plastic piping materials will be used only in applications requiring corrosion-resistant material.

3.16.3 Piping Materials

Piping materials will be in accordance with applicable ASTM, and ASME standards. Materials to be incorporated in permanent systems will be new, unused, and undamaged. Piping materials will be in accordance with the following criteria:

- Steel and Iron Pipe. Carbon steel piping 2-inch nominal size and smaller will be ASTM A53 or A106, Grade B, SCH 80 minimum.
- Carbon steel piping 3 inch through 24-inch nominal size will be ASTM A53 Grade B seamless (welded seam pipe shall be used for low pressure air and water) or A106Grade B, with the indicated grades as a minimum. Carbon steel piping larger than 24-inch nominal size will be ASTM A672 or API 5L Grade B or ASTM A139 Grade B.
- Low chrome alloy pipe will be in accordance with ASTM A335 Grades P5, P11, P22 or P91 seamless or welded.
- Stainless steel pipe will be ASTM A312 Grades TP304, TP304L, TP316, or TP 316L seamless or welded. All stainless steel piping materials will be

fully solution annealed prior to fabrication. The Type 316 materials will be utilized for high resistance to corrosion. The Type 30 and 3 16L materials will be utilized for applications requiring hot working (welding, etc.) and for additional corrosion resistance at welds.

- Schedule numbers, sizes, and dimensions of all carbon steel and alloy steel pipe will conform to ASME B36. 10M. Sizes and dimensions of stainless steel pipe designated as Schedule 5S, 10S, 40S, or 80S will conform to ASME B36.19M. Schedule numbers, sizes, and dimensions of stainless steel pipe not covered by ASME B36. 19M will conform to ASME B36.10.
- Alloy Steel Pipe. Steel piping for acid service will be Alloy 20.
- Galvanized Steel Pipe. Galvanized carbon steel piping will be ASTM A53 Grade B. The piping will be hot-dip galvanized.
- The use of galvanized steel pipe will be limited to systems where a degree of corrosion resistance is required or where codes require the use of galvanized steel pipe rather than black steel pipe.
- Underground piping materials will be non-metallic, ductile iron or cathodically protected carbon steel (see 3.1.7). The material selection will be in accordance with service requirements. Metallic underground piping will be wrapped in accordance with American Water Works Association (AWWA) standards.
- Polypropylene Lined Pipe. Polypropylene lined pipe will be ASTM A53 steel pipe with an applied liner of polypropylene.
- Fiberglass Reinforced Plastic Pipe. Fiberglass reinforced plastic pipe will be selected accordance with the specific service requirements.
- Polyvinyl Chloride Pipe. Polyvinyl chloride (PVC) pipe will conform to ASTM D1785 or ASTM D2241.
- Chlorinated Polyvinyl Chloride Pipe. Chlorinated polyvinyl chloride (CPVC) pipe will conform to ASTM F441.
- High Density Polyethylene Pipe. High-density polyethylene pipe (HDPE) will conform to ASTM D3350 with a Plastic Pipe Institute rating of PE 3406 or 3408.

3.16.4 Fitting Materials

Fittings will be constructed of materials equivalent to the pipe with which they are used, except for special cases such as lined steel pipe.

- Steel Fittings. Steel fittings 21/2 inches and larger will be of the butt welding type and steel fittings 2 inches and smaller will be of the socket welding type, except galvanized steel fittings will be threaded.

- Butt Welding Fittings. The wall thickness of butt welding fittings will be equal to the pipe wall thickness with which they are used. The fittings will be manufactured in accordance with ASME B 16.9. ASME B 16.28, and ASTM A234 or ASTM A403.

- Forged Steel Fittings. Forged steel fittings will be used for socket weld and steel threaded connections and will conform to ASME B 16.11.

- Cast Steel Flanged Fittings. Cast carbon steel flanged fittings will conform to ASME B 16.5 and will be of materials conforming to ASTM A2 16 WCB.

3.16.5 Flanges, Gaskets, Bolting, and Unions

Flanged joints will be in accordance with the following requirements:

- Flange Selection:
  - Flanges mating with flanges on piping, valves, and equipment will be of sizes, drilling, and facings which match the connecting flanges of the piping, valves, and equipment.
  - Flange class ratings will be adequate to meet the design pressure and temperature values specified for the piping with which they are used.
  - Flanges will be constructed of materials equivalent to the pipe with which they are used.
  - Mating flanges will be of compatible material.

- Steel Flanges:
  - Steel flanges will conform to ASME B 16.5;
  - Carbon steel flanges will be forged in accordance with ASTM A105;
  - Chromium alloy steel and stainless steel flanges will be forged in accordance with ASTM A182.

- Brass and Bronze Flanges. Brass and bronze screwed companion flanges will be plain faced and will conform to Class 150 or Class 300 classifications of ASME B 16.24. Drilling will be in accordance with ANSI Class 125 or Class 250 standards. Gaskets will be suitable for the design pressures and temperatures.

- Compressed Fiber Gaskets. Compressed fiber gaskets will be in accordance with ANSI B 16.21, and materials will be suitable for a maximum working pressure of 600 psig and a maximum working temperature of 750°F. Compressed fiber gaskets will be used with flat face flanges and raised face slip-on flanges.

- Spiral Wound Gaskets. Spiral wound gaskets will be constructed of a continuous stainless steel ribbon wound into a spiral with non-asbestos filler between adjacent coils. Spiral wound gaskets shall be in accordance with ASME B 16.20. Spiral wound gaskets will be used with raised face flanges, except for raised face slip-on flanges.

- Gaskets containing asbestos are not acceptable. Gaskets will be suitable for the design pressures and temperatures.

3.16.6 Cathodic Protection

Where required, underground piping steel will be cathodically protected, and electrically isolated from above-ground piping and other steel components.

Under ground firewater piping and components, made of steel, will be protected by a cathodic protection system. All cast iron and HDPE piping and components do not require cathodic protection.

3.16.7 Piping Fabrication

Piping fabrication will generally be in accordance with the requirements of the Piping Fabrication Institute (PFI).

3.16.7.1 Welder Qualification and Welding Procedures

Welding procedures, welders, and welding operators will be qualified in accordance with ASME Section IX code requirements. Backing rings will not be allowed for shop or field welds except where specifically permitted.

3.16.7.2 Nondestructive Examination and Inspection

Inspection and testing of piping will be performed in accordance with the requirements of ASME B3 1.1. Nondestructive examination will generally include visual, radiographic, magnetic particle and liquid penetrant, and ultrasonic examinations.

- Visual examination of welds will be performed by personnel qualified and certified in accordance with AWS QCI, Standard for Qualification and Certification of Welding Inspectors.

- Nondestructive examination shall be performed by personnel certified in accordance with ASNT Recommended Practice SNT-TC-IA.

- Radiographic examination will be performed on welds or welds to pressure retaining components as required by ASME B31.1 LODE.

- Magnetic particle, ultrasonic and liquid penetrant examination will be performed as required by ASME B3 1.1 Code.

3.16.8 Pipe Supports and Hangers

The term "pipe supports" includes all assemblies such as hangers, floorstands, anchors, guides, brackets, sway braces, vibration dampeners, positioners, and any supplementary steel required for pipe supports.

3.16.8.1 Design and Selection Criteria

All support materials, design, and construction will be in accordance with the latest applicable provisions of the Power Piping Code, ASME B31.1. Seismic design of piping systems will be in accordance with criteria as stipulated by the California Building Code.

3.17 VALVES

Valve pressure classes, sizes, types, body materials, and end preparations will generally be as described herein. Special features and special application valves will be utilized where required. Steel body gate, globe, angle, and check valves will be designed and constructed in accordance with ASME B16.34 as applicable.

3.17.1 Iron Body Valves

Iron body gate, globe and check valves will have iron bodies and will be bronze mounted. The face-to-face dimensions will be in accordance with ASME B16.10.

3.17.2 Butterfly Valves

Rubber-seated butterfly valves will be generally constructed in accordance with AWWA C504 Standard for Rubber-Seated Butterfly Valves. The valves will also generally conform to the requirements of MSS Standard Practice SP-67, Butterfly Valves.

3.17.3 Branch Line Isolation Valves

Isolation valves will be provided in 2-inch and smaller branch lines from main piping headers and equipment.

3.18 INSULATION AND LAGGING

The insulation and lagging to be applied to piping, equipment, and ductwork for the purposes of reducing heat loss, and personnel protection will be in accordance with the following criteria:

3.18.1 Insulation Materials and Installation

Insulation materials will be inhibited and of a low halogen content so that the insulation meets the requirements of ASTM C795 and ASTM C929 regarding stress-corrosion cracking of austenitic stainless steel. Insulation materials will contain no asbestos. All piping operating above 140°F will be insulated in areas required for personal protection. All piping will be insulated as required for energy conservation, prevention of condensation and noise attenuation. Equipment and ductwork operating at elevated temperatures. ~~will be insulated with calcium silicate or mineral fiber insulation.~~

3.18.2 Lagging Materials and Installation

All insulated surfaces of equipment, ductwork, piping, and valves will be lagged, except where removable covers are used.

3.18.3 Freeze Protection

All above ground piping smaller than 2-inch nominal diameter and subject to freezing will be insulated and provided with electric heat tracing, if deemed required. In addition, all piping will be evaluated for freeze protection by the following methods: Insulation, electric heat tracing, low point drains, high point vents and schedule 80 piping.

3.19 Lubrication

Types of lubrication specified for facility equipment will be suited to the operating conditions and will comply with the recommendations of equipment manufacturers.

The startup charge of flushing oil will be the manufacturer's standard lubricant for the intended service. Subsequently, such flushing oil will be sampled and analyzed to determine whether it can also be used for normal operation or must be replaced in accordance with the equipment supplier's recommendations.

Rotating equipment will be splash lubricated, force lubricated, or self-lubricated. Oil cups will be provided as necessary. Where automatic lubricators are fitted to equipment, provision for emergency hand lubrication will also be specified. Where applicable, equipment will be designed to be manually lubricated while in operation without the removal of protective guards. Lubrication filling and drain points will be readily accessible.

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4.0 ELECTRICAL DESIGN CRITERIA

This section describes the facility's principal electrical equipment and systems, their functions, and the general criteria upon which their design will be based. An overview is shown on the main single-line diagram.~~ in Appendix B.~~

4.1 Interconnections to Electrical Utilities

Power generated will be delivered to the utility transmission system through a 230kV breaker on the high voltage side of each generator step-up transformer Startup power will be backfed through this same interconnect from the utility system. Protection, control and communication interface will be at the utility plant fence line.

4.2 Electric Power System – General

Power will be generated by a single Combustion Turbine Generator (CTG) operating at 16.5kV and a Steam Turbine Generator (STG) operating at 13.8kV. A generator circuit breaker connects each generator to a 2-winding generator step-up transformer (GSUT) by way of isolated phase bus duct.~~A single 3-winding generator step-up transformer will step up the voltage from each generator for connection to the utility high voltage system.~~ The CTG GSUT is connected to the utility high voltage system by way of overhead line. ~~A short length of underground 230kV solid dielectric cable connects the high voltage winding of the STG GSUT to a takeoff structure located near the CTG GSUT The CT generator will be connected to an 18kV generator breaker with isolated phase bus duct. The line side of the generator breaker will then be connected to the Generator Step Up Transformer (GSUT) via isolated phase bus duct. The ST generator will also be connected to a generator breaker and the line side of that breaker will be connected directly to the GSUT via underground cable~~. This overhead line connects to a single ring bus position of the existing 230kV switchyard~~The HV side of the GSUT will be connected to the existing 230kV switchyard via overhead HV cable~~.

The following general criteria will be used to design the electrical system:

- The electrical systems, equipment, materials, and their installation will be designed in accordance with applicable industry codes and standards, project design criteria, and other requirements as specified.
- Facility power will be supplied through two (2) ~~18kV-~~4.1~~31~~6~~4.16~~kV unit auxiliary transformers connected to the 4.16kV switchgear. Emergency power will be provided by connection to a 12kV line currently in place at the existing plant. This connection will be made into a 480V switchgear via a 12kV-480V transformer. ~~.An emergency diesel generator will be provided to feed plant auxiliary electric loads in the event of a loss of the 230kV system, thereby allowing a safe plant shutdown.~~ During normal startup, power required for auxiliaries will be supplied from the utility through the CT generator step-up transformer to the ~~18kV-4.16~~medium voltage (MV)~~-4.16kV~~ unit auxiliary transformers.

- The 4160V system will be fed from the MV~~4160V~~ unit auxiliary transformers. Each of the 4160V switchgears will be double-ended, low-resistance grounded, and located in a separate Power Distribution Centers (PDC).
- The 480V system will be fed from 4.16-480kV secondary unit substation transformers. Each 480V low-voltage switchgear will be double-ended and high-resistance grounded. The 480V motor control centers will be fed from the 480V low-voltage switchgear. ~~The emergency generator will be connected to the 480V switchgear to provided shut down capability to the plant in event of a loss the 230kV system.~~
- Equipment will be sized to handle the maximum required current. The unit auxiliary transformers, 4160V equipment, and 480V switchgear will all be sized to handle the load of the entire plant configuration.
- Equipment short-circuit ratings will be based on the maximum short-circuit currents under all operating conditions and will take into account equipment design margins~~ and the standby generator testing~~. There are no provisions for future loads.
- Motors greater than 200 hp will be supplied from the 4160V system. Motor-operated valves and motors from ¾ hp up to and including 200 hp will be supplied from the 480V system. Motors less than ¾ hp will be fed from the 120V system.
- The electrical power distribution system design and cable sizing will be selected to limit the cable voltage drop from source to load to not more than 5 percent. The allowable voltage variation at the load equipment will be limited to ±10 percent of the load nominal voltage rating under normal continuous operating conditions. The electrical system design will also be based on motor starting and system capability requirements.
- Electrical and controls equipment requiring access for normal operation and/or maintenance will be accessible from permanent floors or platforms without scaffolding, portable ladders, or lifts. Access space and clearance for electrical equipment will be per manufacturer's recommendation and in accordance with NEC requirements.
- ~~The protective relaying, metering, and controls for all electrical equipment will be according to the Engineer's design schematic diagrams, connection diagrams, and metering & relaying one-lines.~~

4.3 Plant DC Power Systems

Plant DC will be supplied from 125VDC and 24VDC battery systems. Emergency power for the CTG critical loads will be supplied by the 125VDC battery system supplied with each CTG. Control power for the plant electrical equipment, e.g. switchgear will be supplied by the station 125VDC battery system.

The station 125VDC system will consist of one (1), 100% capacity battery bank, two 100% capacity battery chargers, battery management system, a switchboard, and the required 125VDC panelboards. The batteries will be lead-acid. This system will supply DC power requirements for the uninterruptible power supply (UPS) system, medium and low voltage switchgear, balance of plant, and any critical DC loads. The station 125VDC system will be sized to supply the plant emergency loads for a period long enough to allow a safe shutdown of all plant equipment including the CTG, gas compressor, etc. The battery will be sized in accordance with IEEE 485. Battery racks will be designed to applicable project specific seismic zone requirements.

Each battery charger will be sized to supply the normal DC loads while simultaneously recharging a fully discharged battery in twelve (12) hours or less. Each charger will be designed such that it may be operated as a battery eliminator with the battery disconnected.

The batteries will be connected to the DC switchboard through a disconnect switch. The switchboard and panelboards will be designed for indoor installation and constructed in accordance with NEMA PB-1 and PB-2. Each panelboard will be provided with 20 percent spare breakers and will be fully equipped.

The following 125VDC typical loads will be fed from the station battery:

- MV and LV switchgear control power
- BOP DCS Power Supply
- CTG control system
- Plant UPS Power System
- ST/CT Lube Oil Systems

4.4 Uninterruptible Power Supply (UPS) System

Single phase UPS inverters will supply 120VAC single-phase power to the UPS panelboards that supply critical AC loads. The UPS inverter will be fed from the station 125VDC battery. The UPS system will include one inverter, one alternate source transformer, one static transfer switch, one manual bypass switch, and required panelboards. The manual bypass switch will operate to completely bypass either inverter while continuing to provide power to all panelboards. In the case of an inverter failure, the alternate 480 VAC source will supply power to the AC panelboard via the alternate source transformer and the associated static transfer switch. The alternate source transformer will be shielded and non-regulating.

The following loads will be supplied from the UPS:

- DCS operator stations
- CEMS PLC and DAS computer
- Solenoid operated valves (via DCS)
- Communication equipment
- Revenue metering SCADA equipment
- CTG UPS loads
- Fire Protection Alarm System

4.5 Main Generators

The gas turbine generator will be ~~of either~~ Totally Enclosed Water to Air (TEWAC) design~~or hydrogen cooled design~~. The combustion turbine generator will be synchronized to the utility's transmission system using the associated low side (16.5~~8~~ kV) generator breaker.

The steam turbine generator will be ~~of either~~ Totally Enclosed Water to Air (TEWAC) ~~or hydrogen cooled~~ design. The steam turbine generator will be synchronized to the utility's transmission system using the associated low side (13.8 kV) generator breaker.

The CTG and STG will be capable of remote automatic generator control and will be supplied with metering quality CTs, PTs and meters capable of supplying signals to the DCS and performance monitoring systems.

4.6 Generator Step-up Transformer (GSUT)

~~A~~A ~~single 3~~2-winding, delta-wye, ONAN/ONAF/ONAF 65°C rise GSU transformers will connect each of the CTG and the STG to the 230kV system. The neutral point of the HV winding of each transformer will be solidly grounded. ~~The~~ Each GSU transformer will have metal oxide surge arresters adjacent to the HV terminals.

Transformer accessories will include a magnetic liquid-level gauge, pressure-relief device, buckholz relay, oil preservation device, valves for top and bottom filter press connections, drain/sampling valves, grounding pads, bushing-mounted current transformers, combustible gas detector, and hot spot winding temperature elements.

Each~~The~~ GSUT will include a manual de-energized tap changer located in the HV winding with taps ranging from 5 percent above normal to 5 percent below normal in 2.5 percent increments. The tap changer will have manual locking provisions.

Each GSU transformer's auxiliaries will be powered from a 480V, three-phase source.

4.7 Unit Auxiliary Transformers (UAT)

Two (2) ~~18kV~~ 4.1~~3~~6kV ~~4.16kV~~ two-winding delta-wye ONAN/ONAF 65°C UAT will be provided to serve all plant auxiliary electric loads. Each UAT will be rated to supply facility startup and maximum operating power requirements. The neutral point of each 4160V UAT will be low-resistance grounded.

Transformer accessories will include a magnetic liquid-level gauge, pressure-relief device, sudden pressure relay, oil preservation device, valves for top and bottom filter press connections, drain/sampling valves, grounding pads, bushing-mounted current transformers, and hot spot winding temperature elements.

Each UAT will include a manual de-energized tap changer located in the HV winding with taps ranging from 5 percent above normal to 5 percent below normal in 2.5 percent increments.

4.8 Secondary Unit Substation Transformer (SUS)

Multiple 4.16-0.48kV two-winding delta-wye AA~~ONAN~~/~~ONAF~~FA 115~~55~~°/115~~65~~°C SUS transformers will be provided to serve the 480V switchgear and all 480V plant auxiliary electric loads. The SUS transformers will be rated to supply facility startup and maximum operating power requirements. The neutral point of the 480V SUS transformers will be high-resistance grounded with a ground fault detection scheme consisting of a pulsing contactor in the neutral circuit to aid in identifying ground faults.

Accessories will include a ~~magnetic liquid level gauge, pressure relief device, sudden pressure relay, oil preservation device, valves for top and bottom filter press connections, drain/sampling valves,~~ grounding pads, bushing-mounted current transformers, and hot spot winding temperature elements.

The SUS transformers will include a manual de-energized tap changer located in the HV winding with taps ranging from 5 percent above normal to 5 percent below normal in 2.5 percent increments.

4.9 Power Distribution Centers (PDC)

Power Distribution Centers (PDC) will house all 4.16kV switchgear and motor control centers, 480V voltage switchgear, low voltage MCCs, DCS panels, power and lighting panels, revenue metering, protective relaying, station batteries~~,~~ ~~CAISO RIG and~~ other miscellaneous equipment.

Each PDC will be equipped with redundant HVAC systems, smoke detection and lighting & convenience receptacles. ~~Each electrical equipment area will be equipped with a wall mounted maintenance switch. This switch will be placed in the "maintenance" position whenever the switchgear area is occupied. When operated, this switch will remove all time delays in the main protective relays thereby making them essentially instantaneous trip relays. This action has the effect of lowering the arc flash hazard to a safe level as defined by NFPA 70E.~~

The PDC will be shipped to site with all wiring completed between all internal components.

4.10 Medium Voltage Switchgear

~~4.10Medium Voltage Switchgear~~

Two lineups of 4.16kV medium voltage switchgear will be provided. This switchgear will be ~~1~~5kV class nominal, three-phase, three-wire with ratings not to exceed 3000A continuous and 50kA fault current duty. The medium voltage system will be ~~high~~low-resistance grounded via the ~~CTG~~ UAT neutral grounding ~~transformer~~ resistors~~when the generator breaker is closed, and will be ungrounded when the generator breaker is open. A set of zero-sequence PT's and ground fault protection are required for each MV switchgear bus to monitor for bus ground faults prior to closing the generator breaker~~.

The medium voltage switchgear will be located indoors, will use vacuum interrupters, and will be rated to continuously distribute the full auxiliary load. Each lineup will contain voltage transformers, protective relaying for the~~ GSUT,~~ UAT, and feeder breakers and other load distribution equipment. All medium voltage breakers will be electrically operated from the DCS and equipped with a stored energy mechanism.

4.11 Medium Voltage Motor Controllers

The medium voltage motor controller lineup will be rated 4.16kV nominal, three-phase, three-wire with bus ratings not to exceed 1200 amps continuous and 250MVA fault current duty. The MV MCC will be NEMA Class E2 rated equipment. The MV MCC will be double high construction and drawout where possible. The MV MCC will contain vacuum and control power will be via an internal control power transformer. All motor controllers will be controlled from the DCS. The medium voltage motor controller lineup will consist of motor controllers and a main load-break switch.

The 4160V medium voltage controllers will be rated 4.16V nominal, three-phase, three-wire switchgear with ratings not to exceed 3000A continuous and 50kA fault current duty. The MV controllers switchgear will be sub-fed by the main 4.16kV switchgear through a cable connection.

4.12 Low Voltage Switchgear

The low voltage switchgear will be rated 480V nominal, three-phase, three-wire with ratings not to exceed 4000 amps continuous and 100 kA fault current duty. The low voltage switchgear will use electrically operated air-break power circuit breakers controlled from the DCS. Each power circuit breaker will have a solid-state trip device. If an electric fire pump is required, its feeder will be mechanically operated only. The low voltage switchgear will supply power to the low-voltage MCCs. The low voltage switchgear will be located indoors. The low-voltage switchgear will receive 480V power from the 4.16kV-0.480kV transformer through non-segregated phase bus duct.

A multimeter will be mounted on the front of each low-voltage switchgear to display bus voltage and current, kW, and kVAR for the incoming feed to that low-voltage switchgear.

Each low voltage switchgear will be designed with an integral high resistance grounding system with a self-contained annunciator and pulsing contactor. Ground fault detection will be provided with an alarm indication to the DCS.

All low voltage switchgear will have provisions and to accommodate a future vertical section.

4.13 Low Voltage Motor Control Centers

Low voltage motor control centers (MCCs) will be rated 480V nominal, three-phase, three-wire and will supply 480V non-motor loads, motors from ¾ hp up to and including 200 hp, motor-operated valves, and lighting and distribution panels. Thermal magnetic molded-case circuit breakers will be used for non-motor loads. Each motor starter will consist of a padlockable motor circuit protector; three-phase overload protection; three-pole contactor; hand-off-auto switch; stopped and running indication lights; and control power transformer. Control power transformers will be sized to handle each individual motor space heater load. The MCC bus bracing and starter interrupting ratings will be consistent with the short-circuit currents calculated during detail design. All motor control centers will be installed indoors.

A minimum of 10% spare starters will be provided for the following: size 1 FVNR starters, size 2 FVNR starters, 150A breakers, 225A beakers in each lineup.

Placards will be placed on each motor control center starter to warn that operation of the equipment in "hand" position bypasses all permissives.

All motor control centers will have provisions and space to be extended a minimum of 1 vertical section.

4.14 Motors

~~This section addresses motors for BOP equipment.~~ Motors employed for balance-of-plant equipment will be the squirrel-cage induction type suitable for full-voltage across the line starting. The motor nameplate at service factor load will not be less than 1.15 times the maximum brake horsepower (KW) of the driven load. Motors will be provided with Class F insulation with Class B rise. Motor locked-rotor current will be limited to 650% of full load current at rated voltage. All medium voltage motors will be suitable for starting at 80% of the motor nameplate voltage.

All motors rated above 200 hp will be rated 4000 V, will be weather-protected Type II (outdoor), Type I (indoor only), totally enclosed fan cooled (TEFC), or totally enclosed water air cooled (TEWAC), depending on application. Motors rated 4000 V will include two resistance temperature detectors (RTDs) per stator winding and one RTD for each sleeve bearing wired to a terminal block.

All motors rated ¾ to 200 hp and fractional horsepower reversing motors (e.g. electric actuators) will be rated 460V, totally-enclosed fan-cooled (TEFC). ~~, and will be designed in accordance with the IEEE 841 standard.~~

Motors less than ¾ hp and smaller will be rated 110 VAC.

Motors rated 25 hp and above will have space heaters. The space heater will be serviceable or replaceable without disassembly of the motor. The space heater terminal box will be separate from the motor termination box. Where possible, the motor space heaters will be rated for 240 VAC but sized and energized at 120 VAC. Space heaters rated for 120VAC will also be allowed if 240VAC rated heaters are not available.

Motors will be furnished with oversized ~~cast iron~~ terminal boxes ~~and will be capable of rotation in 90-degree steps~~. 4000 V motors will be provided with two grounding pads. Antifriction bearings will be grease lubricated, self-lubricating, and regreasable. ~~Anti-friction bearings will have a L_{10} bearing life of 100,000 hours.~~ 4000 V motors will be equipped with vibration switches or probes when specified and wired out to a terminal box for customer wiring.

Motor data sheets will be provided for all three-phase motors, including those contained in vendor package equipment.

Routine tests will be performed on motors in accordance with NEMA MG-1 and IEEE 112.

4.15 Electrical Protection

Protective devices will be coordinated to the extent feasible to interrupt electric disturbances (fault, overload, abnormal operating condition, etc.) at the point nearest the fault, with the next upstream protective device providing back-up protection.

Protective devices will operate through a lockout relay (86) or equivalent latching device or circuit to prevent automatic restart/reclose of the equipment.

The protection settings of the ~~69kV18kV~~ generator~~69kV~~ breakers and generator protective devices will be fully coordinated with the utility system protection.

In general, relays will be micro-processor based, multi-function type. Drawout protective relays will have provisions for their removal without tripping their associated circuit breakers. Protective relays and lockout relays will be provided ~~with ABB FT-1 type~~ external test switches to allow for the functional testing of the protective relaying and their associated circuits. The test switches will be provided for voltage and current inputs as well as relay trip outputs (normally-open contacts on lockout relays).

As a minimum, the following protection will be provided for:

- CTG (provided by the turbine generator supplier)
  - Generator differential (87)
  - Negative sequence (46)
  - Loss of excitation (40)

- Reverse power (32)
- Stator ground (64G or 59GN)
- Volts/hertz (24)
- Overvoltage (59)
- Overfrequency and underfrequency (81)
- System Distance Backup (21)
- Voltage balance (60 FL)
- Field ground (alarm only)
- Out of Step (78)
- Breaker failure (50BF) (For generators with low-side breakers)
- Accidental Energization (50/27)

* Power transformers (each GSU and UAT)
  - Transformer differential relay (87T) or overall unit differential (87U)
  - Transformer neutral overcurrent (51TN)
  - Transformer phase instantaneous overcurrent (50)
  - Transformer phase time overcurrent (51), other than main step-up transformers
  - Restricted ground fault protection (87GD) – Unit auxiliary transformer low voltage windings only.
  - Transformer fault pressure relay (63)
  - Oil level switch (71Q) (alarm only)
  - Oil temperature (26Q) (alarm only)
  - Winding temperature (49) (alarm only)
  - Overpressure (alarm only)

  - Main step-up and unit auxiliary transformer protection relays will be SEL-387E or equal.

* MV buses (4.16 kV)
  - Bus under voltage for alarm (27) and blown secondary VT fuse indication (60)
  - Incoming phase time overcurrent (51)
  - Incoming residual ground time overcurrent (51G)
  - Bus ground fault detection (59G) on the MV busses to detect bus faults prior to closing the generator breaker.
  - ~~Main incoming protection relay will be Schweitzer SEL-351A or equal.~~

* 4.16-0.480kV transformers (protection located in the 4.16kV switchgear)
  - Phase time overcurrent (51)
  - Phase instantaneous overcurrent (50G – zero sequence)

  ~~o Feeder protection relay will be Schweitzer SEL-351A~~

* 4000 V motors
  - Thermal overload (49)

- Phase overcurrent (51)
- Phase instantaneous overcurrent (50– provided by contactor fuse)
- Ground overcurrent (50G - zero sequence)
- Phase reversal (47)
- Stator overtemperature (when required by the P&IDs) (alarm and trip)
- Bearing overtemperature (when required by the P&IDs) (alarm only)
- Phase current unbalance (provided through thermal overload protection)
- Vibration (when required by the P&IDs) (alarm and/or trip as indicated by P&IDs)
- Motor and feeder protection relay will be Schweitzer SEL-701 or equal
- ~~Motor and feeder protection relay will be Schweitzer SEL-701~~

- LV switchgear buses (480 V)
  - Bus under voltage for alarm and blown secondary VT fuse indication
  - LT/ST protection on main, tie, and MCC feeder breakers
  - LT/ST/I protection on motor feeders
  - Ground fault alarm
- 480 V motors fed from MCCs
  - Thermal overload and motor circuit protector
- Panels, transformers, heaters and miscellaneous loads fed from MCCs
  - Thermal-magnetic molded-case circuit breaker

4.16 Metering

4.16.1 Metering - General

~~Separate revenue metering for each CTG will be provided to allow independent dispatch of each unit into the ancillary services markets.~~ Metering class CT's & PT's will be provided in the generator breaker associated with each CTG. Space for the revenue metering should be provided in the PDC, but may be approved for outdoor installation if approved by CAISO and PG&E revenue metering representatives.

Metering of plant auxiliary power during standby will be provided by a PG&E revenue metering installation on each~~the 18kV-4.16kV~~ UAT transformer. ~~Metering of plant auxiliary power during standby will be provided by thean PG&E revenue metering installation on the 18kV-4.16kV transformer.~~ This revenue meter installation will be configured to monitor auxiliary power consumption when both generator breakers are open and the plant is in a standby mode. This meter will be enabled when both generator breakers are open and disabled if either one or both of the generator breakers are closed. The final aux electric metering configuration, metering instrument transformers and test switches will must be reviewed and approved by the local utility prior to installation.

Relaying class accuracy voltage and current transformers are acceptable for panel indication meter applications.

~~ABB FT-1 type t~~Test switches will be provided for the voltage and current inputs to each meter.

4.16.2 Metering Locations

Indication metering will be provided in the following locations:

- Each generator (voltage, current, kW, kVAR, kWHr, kVARHr, pf, and freq)
- Each generator~~18kV~~ breaker (voltage, current, kW, and kVAR) ~~– SATEC PM172P Series Multimeter~~
- The 4.16kV main breaker (voltage, current, kW, and kVAR)~~– SATEC PM172P Series Multimeter~~
- Each low voltage main breaker (voltage, current, kW, and kVAR)~~– SATEC PM172P Series Multimeter~~
- Each medium voltage motor (current) – provided ~~through SEL-701~~ motor protection relays
- Low-voltage motor control centers (voltage, current, kW, and kVAR)~~– SATEC PM172P Series Multimeter~~
-
- 125 VDC BOP systems:
  - Battery amperes (at DC switchboard)
  - Bus voltage (at DC switchboard)
  - Negative to ground (at DC switchboard)
  - Positive to ground (at DC switchboard)
  - Blown Fuse (at each fused switch in DC switchboard)
  - Each charger output volts and amperes
- 120 VAC UPS system
  - Each inverter input volts and amperes
  - Each inverter output amperes, voltage, and frequency

4.17 Annunciation to Plant Computer System

The following points at a minimum will be wired to the plant computer system for indication:

Revenue meters: (through datalink)

- MW export (if applicable)
- MW import (if applicable)
- MVAR import

- MVAR export
- MWHr export
- MWHr import (if applicable)
- MVARh export
- MVARh import
- System voltage

Generators (either through the datalink with the turbine control system, if available, or hard-wired directly to BOP DCS).

- Generator gross watts
- Generator gross watt-hours
- Generator gross amperes (each phase)
- Generator gross vars
- Generator gross var-hours
- Generator volts (each phase)

Generator Step-Up Transformer (GSUT):

- Common trouble alarm (DI)
- Transformer temperature (4-20mA)
- Water concentration (4-20mA)
- Hydrogen concentration (4-20mA)

Unit Auxiliary Transformer (UAT):

- Common trouble alarm (DI)
- Transformer temperature (4-20mA)

Each 4.16kV-480V Transformer:

- Common trouble alarm (DI)

Each Medium Voltage Switchgear Lineup:

- Bus voltage (through datalink)
- Main breaker current, kW, and kVAR (through datalink)
- Transformer and MCC feeders current, kW, and kVAR (through datalink)
- Motor feeders current (through datalink)
- Bus undervoltage indication (DI)
- Instrument voltage transformer blown fuse indication (through datalink)
- I/O as defined on standard schematics

Each 480V Switchgear:

- Ground fault alarm
- Bus phase A-to-B voltage (4-20mA)
- Main breaker phase B current (4-20mA)

125VDC System:

- One common trouble alarm from each battery charger
- One common trouble alarm from each 125VDC switchboard
- One common alarm from each battery management system

120VAC UPS System:

- One common trouble alarm from the UPS inverter
- Position of each main breaker/switch on each UPS panelboard
- Manual bypass switch position

4.18 Controls

4.18.1 Synchronizing

The CTG and STG will be synchronized automatically from the ~~balance of~~ plant DCS through the units respective synchronizing system, which is included as part of each generator package. In addition, the CTG will also be complete with vendor supplied controls to allow the CTG to be synchronized from the local CTG control room. The synchronizing system will control turbine speed/generator frequency, generator voltage, and breaker closure (factoring in breaker historical closure time). No remote manual synchronizing capability is required. Synchronizing breaker selection will be performed through the turbine control system.

4.18.2 Automatic Generation Control

Automatic Generation Control and Monitoring will be provided. ~~The control will be by the plant DCS system via a CAISO Remote Intelligent Gateway (RIG) installed in the PDC or from NCPA dispatch load balancing.~~

4.18.3 Medium Voltage Breaker Control

All medium voltage breakers and contactors when in the “in service” position will be controlled through the DCS. Local closing will only be allowed when the breaker or contactor is in the test position. Local opening will be allowed in either the “in service” or “test” position.

Control schemes for all medium voltage switchgear and motor controllers will be submitted for Owner's review prior to release for manufacturing.

4.18.4 480V Control

All 480V electrically operated switchgear breakers when in the "in service" position will be controlled through the DCS. Local closing will only be allowed when the breaker is in the test position. Local opening will be allowed in either the "connected" or "test" position.

480V starters that control process loads will be controlled from the control room through the DCS. Equipment such as HVAC, air compressors, small sump pumps, CEM, etc., will be locally controlled only, with no remote control.

Non-reversing motor control from the DCS will be via a maintained start/stop contact. Reversing motor control from the DCS will be via open/close contacts.

Control schemes for all low voltage switchgear and motor controllers will be submitted for Owner's review prior to release for manufacturing.

4.19 Communications and Security Systems

The telephone system and security system will be provided as discussed in the following subsections.

4.19.1 Telephone Communication System

The in plant telephone system will consist of a dedicated telephone exchange with an integrated voice mail system. The system will be either a retrofit of the existing plant system or a new, separate system will be provided.~~The main switching termination and isolation equipment will be located in an administatration building a PDC. Nineteen inch rack(s) will be provided and installed for this equipment. This will also be the termination point for the two 50 pair offsite telephone lines coming into the site.~~

~~The standard telephone system capacity will be as follows:~~

~~One local T-1 with 200 DID block.~~

~~One dedicated long distance T-1~~

~~4 – Centrex Lines~~

~~1- ISDN line for WAN back-up~~

~~6 – Copper backup PBX trunks (4 DID, and 4 COT)~~

~~1 Analog fax line~~

4.19.2 Computer Network System

The in plant computer system will consist of a local area network with the main switching, termination and isolation equipment located in the electronics room adjacent to the control room as described in the Instrument/Control Design Criteria.

4.19.3 Security System

The plant security system will consist of a surveillance camera at the main gate and one monitor in the plant control room. Additional cameras may be located at other places in the facility, e.g. water treatment, top of boiler, etc.

The main gate will be controlled from a programmable keypad at the gate and from the main control room. An intercom system will be provided from the main gate to the control room. Automatic opening/closing features of the gate will be provided for vehicles exiting the plant.

4.20 Cable and Raceway

In general, equipment at grade not located near overhead pipe or cable tray racks will be fed from underground ducts with other equipment generally connected using above grade cable tray and conduit systems. Where cable tray is routed in pipe rack with piping, the cable tray will be routed at the top elevation of the pipe rack above all piping. Covers will be provided if considered necessary for protection against welding slag or other debris.

Unless otherwise noted, all cables routed underground will be installed in marked concrete or cement slurry encased duct bank. Above ground circuits will be installed in conduit or tray. Grouped electrical cables should be routed away from exposure hazards or protected as required by the Fire ~~Design~~ Mitigation Plan. In particular, care should be taken to avoid routing cable trays near sources of ignition or flammable and combustible liquids. Where such routing is unavoidable, cable trays should be designed and arranged to prevent the spread of fire.

The final design will provide a minimum of 10 percent spare conduits in each duct bank. In no case will there be less than one spare conduit provided for each application utilized in that duct bank, (power, control, instrumentation).

Cable trays will be designed for 35% fill. Cable tray will be aluminum unless otherwise required due to environmental or corrosion issues.

Separation of voltage levels in all raceways will be maintained to meet the CTG manufacturers cable separation requirements or industry codes and standards whichever is more conservative. Rigid galvanized steel conduit will be used in duct banks when required for signal separation. Otherwise, conduit in ductbank will be PVC. All above ground conduit will be RGS (rigid galvanized steel).

Manholes will be provided as required for cable installation. Each manhole will be provided with a sloped floor to a 2'X2'x2' deep sump for pumping out water with a portable submersible pump. Duct banks will be sloped toward manholes where possible. The slope determination will be made to suit site conditions.

Hazardous area classifications and fire rated barrier requirements will be identified by the design engineer.

4.21 Grounding

The facility grounding grid system will consist of buried stranded copper conductors and ground rods, and ground wells as required. The buried grounding conductors will be sized on actual maximum available fault current in the switchyard. Exothermal welded type connectors ~~that meet the requirements of IEEE 837~~ will be used for the buried ground grid connections. Exothermal welded connectors will be used above ground for connection of the ground grid to building steel. NEMA approved crimp on cable lugs will be used for connection of the ground grid to equipment.

The ground resistivity will be measured in accordance with IEEE 81 or ASTM G57. The ground grid will be designed so that the step, touch, and mesh potentials are within acceptable levels per IEEE 80 and IEEE 695. The calculated ground grid resistance will be verified by measuring final grounding resistance by Fall-of-Potential method per IEEE 81. The ground grid design will take into account the nearby substation and will be tied into the grid of the substation in at least 2 places.

Equipment and electrical systems in the plant power block area will be grounded in accordance with the Owner's standard grounding details, the National Electrical Code (NEC) and IEEE 142. All major electrical equipment will be grounded directly to the ground grid. The communication, instruments, and control cable shields will be grounded per the Owner's standard grounding details, IEEE 789, the turbine supplier's requirements, and the DCS supplier requirements as applicable.

4.22 Cathodic Protection

Because of the potential hazard in case of a leak, cathodic protection will be provided for all buried, coated-carbon-steel pipe including natural gas pipes. The cathodic protection system for buried pipes will be sacrificial galvanic anode system unless soil conditions or pipe size require the use of an impressed current system. Cathodic protection will be designed to meet NACE RP-01-69.

All underground piping systems, tanks, large heat exchangers, condensers will be reviewed for cathodic protection by the Owner prior for release for manufacturing on installation.

Field-erected storage tank bottoms will be set on a concrete ring-wall or slab foundation. Cathodic protection will be provided if required.

4.23 Lightning Protection

It is not expected that lightning protection will be required for any plant site or structure located at any plant site. ~~However, lightning protection will be provided as required by the Owner in specialized locations such as near the high voltage side of the GSUT.~~

4.24 Lighting Systems

As a minimum, lighting will be provided in the following areas:

- Building interiors.
- Building exterior entrances.
- Outdoor equipment within the power block and tank area.
- Power transformers.
- Power plant roadways.
- Parking areas within the power block area.
- Entrance gate.

Lighting levels will be as recommended in IES standards.

Suitable fixtures will be specified and installed according to the hazardous area classification.

Emergency lighting will be provided by integral battery packs and will not be connected to UPS system or 125 VDC station battery. Emergency lighting will be provided for safe egress from all plant areas. Emergency lighting will be provided with battery packs as well as connected to the plant 120V system.

If specified in Section 1, Stack aviation warning lighting will be installed per FAA advisory circular AC 70/7460-1.

The lighting circuits will consist of minimum #12 AWG stranded copper conductor.

Cables used for lighting circuits will be XHHW-2. In outdoor areas, the circuits will be provided with rigid steel galvanized conduits with weatherproof fittings.

Outdoor lighting will be switched and photocell controlled through contactor's that feeds/controls the outdoor lighting. Light poles will be galvanized steel or aluminum. To reduce the visual impact created by outdoor lighting, the following mitigation measures will be adopted:

Lighting on the project site will be limited to areas required for safety and will be shielded from public view to the extent possible.

Lights will be directed on site so that significant light or glare will not be created. Highly directional, high-pressure sodium vapor fixtures will be used.

Nighttime backscatter illumination will be avoided by directional shielding of lights and providing on/off switch at the bottom of the ladders and stairways. All light switches will be clearly identified.

LV distribution panelboards for lighting and receptacles will be sized to distribute the capacity of the supplying transformer and will be located near the loads connected to each panel. Such panels will include a minimum of 20 percent spare breakers and all spaces will be equipped. Panels will include a main breaker as required by the NEC. All plant lighting panelboards will be located indoors, to the extent practical.

Distribution transformers will be sized to supply the expected continuous load, with approximately 20 percent margin for future load growth. The transformers will be air-cooled, dry type, with a 150° C rise. When it is required that the panelboard and/or transformer are located outdoors, the panelboard will have a minimum NEMA 3R rating and the transformer will be equipped with drip shields.

4.25 Freeze Protection / Electric Heat Tracing

The following paragraphs are intended to serve only as a guideline for defining freeze protection, heat tracing and insulation of systems that could potentially be damaged by freezing. Freeze protection methods will consist of the use of self limiting, insulated electric heating cables for low temperature lines and mineral-insulated (MI) for high temperature lines, heated "doghouses," insulation, sparging with heated water, etc. Although pipe or equipment insulation is referenced in Section 3, it will be considered an integral part of the freeze protection system.

For items located outdoors, the heat tracing system will be provided for freeze protection at site minimum ambient temperature and weather conditions. Freeze protection will be provided for all piping systems indoors or outdoors which are subject to freezing during plant operation and shutdown. Sufficient cable will be provided for all flanges, valves and piping specialty items to permit maintenance of these items. The heat tracing system will provide a controlled amount of heat to maintain the temperature above the freezing point, or, in the case of process protection, maintain proper viscosity, temperature or other parameters required for process operation. Lines requiring freeze protection normally include (but will not be limited to) water lines, instrument lines, instrument transmitter housings, safety showers, eyewash stations, and condensate lines.

Where freeze protection is required on fire protection, the design will be in accordance with NFPA standards.

Freeze protection will be provided in accordance with the P&IDs for all piping systems, equipment, tubing, gages and instrumentation that contain fluids subject to freezing. All tubing requiring heat trace will be thermostatically controlled to prevent boil off of the sensing fluid. Above grade, freeze protected piping that continues below grade will be insulated and heat traced below frost depth.

Space heaters or heated enclosures will be used for items where heating cables and insulation is not practical. Power for the heating cable circuits will be supplied from distribution panels similar to those used for the lighting circuits and will be controlled by locally mounted individual thermostats. The freeze protection system will provide local status and alarm indication for each circuit. Each circuit will be provided with electronic monitoring that indicates heat trace proper operation, failure or damage conditions.

Where required, instruments will be freeze protected by utilizing heated "soft-pack" type enclosures. Heaters will be centrally located within the enclosures and rated for extreme plant ambient temperature and wind speed. All process tubing will be continuously heat traced and insulated through the enclosure wall up to the base of the instrument.

4.26 Welding and Convenience Receptacles

Welding receptacles with local disconnects (480 V, 60 amp) will be provided in convenient locations throughout the plant. This includes two at the bottom of each HRSG on opposite sides, two near each CTG, one near the gas compressor area, and one near each PDC.

Convenience receptacles (120 V) will be provided around the plant as follows:

- PDC per the manufacturer's standard scope of supply, but no less than three (3).
- Mechanical and Electrical Enclosures. One duplex receptacle for each enclosure
- General Plant Area to allow a 100-foot extension cord to reach all areas that require power for maintenance.
- Inside the CEMS enclosure and near the gas compressor area.

Outdoor convenience receptacles will be the weather proof GFCI type.

4.27 Temporary Construction Power

Construction Power requirements will be arranged for by the construction ~~C~~contractor to meet construction needs including service to Construction Offices, Vendors, Engineers, and Sub-Contractors, plus 250 KW of start-up loads until back feed is available. The Contractor is responsible for the entire temporary power system design, supply, installation, safety inspection, maintenance, and removal.

Temporary power will be supplied by the construction ~~C~~contractor for space heaters, motor heaters, temporary heaters, and lighting as required for proper storage of material or equipment supplied by the Contractor, Owner or others.

~~4.28Temporary/Construction Telephone Service~~

~~The Contractor will provide telephone lines and T-1 (data) lines as required to a service pedestal at the site boundary that will serve as temporary telephone lines.~~

5.0 CONTROL AND INSTRUMENT DESIGN CRITERIA

5.1 General

The complete plant will be monitored and controlled by a Distributed Control System (DCS).

Auxiliaries such as small sump pumps that need not be in continuous operation for electric power production will be monitored, controlled, and protected locally, with limited DCS monitoring and control.

5.2 Automatic Generation Control (AGC)

The plant will be capable of set point remote block Automatic Generation Control (AGC) from CAISO or NCPA dispatch. The reference point for the AGC will be the net plant revenue meter(s) on the generator step-up transformer(s).

Plant data will be communicated to Pacific Gas & Electric (PG&E) and CAISO. The inputs required must be provided by PG&E/CAISO and an example is indicated in the table below:

INPUTS REQUIRED						
ITEM	**STATUS/UNITS**	**MW**	**MVAR**	**MW-HR**	**MVAR-HR**	**COMMENTS**
T-Line Revenue Metering Point (each)	Ok/trouble	X	X	X	X	
GSUT High Side voltage	kV					
GSUT High Side Frequency	Hz					
High Voltage Circuit Breaker(s)	Open/close/trip					
AGC Set Point	MW					Feed back
AGC High and Low Limits	MW					
Generator Circuit Breaker (CTG)	Open/Close/Trip					
Generating Unit (each)	On/Off, AGC enabled	X	X	X	X	
High Temperature Control Limit	Deg F					
Gas Turbine Inlet Air Temperature	Deg F					
Ambient Air Temperature	Deg F					
Net Plant Fuel Flow	MMBTU/Hr and Standard Cu-Ft/HR					
Auxiliary Power		X	X	X	X	

INPUTS REQUIRED						
ITEM	**STATUS/UNITS**	**MW**	**MVAR**	**MW-HR**	**MVAR-HR**	**COMMENTS**
Transformers						

5.3 Distributed Control System (DCS)

The DCS will provide control of the balance of plant equipment. The balance of plant control system will interface with the CTG Turbine Control Panel (TCP), Steam Turbine Control Panel, Duct Burner Management System PLC, Gas Compressor PLC, CEMS PLC, Ammonia System PLC, Air Compressor PLC, water treatment system PLC, auxiliary boiler PLC and HRSG PLC to provide routine operator control including start-up, shut down, synchronizing, and set point load control from the balance of plant console.

In addition to the control interface provided by the balance of plant control system, the primary equipment to produce electric power, the CTG and related auxiliaries, will also be monitored, controlled, and protected via the Turbine Control Panel provided by the turbine supplier.

The DCS processors will be centrally located in one of Power Distribution Centers located in the new plant. The DCS I/O racks will be distributed around the site in the Power Distribution Centers and water treatment area. The DCS communication network will be a redundant Ethernet, with dual data links to equipment PLCs and dual connected workstations in the Control Room.

Packaged systems (where applicable), except as noted herein, will be programmed into, and controlled by the DCS. Control of the continuous emissions monitoring system (CEMS), HRSG, gas compressor, auxiliary boiler, water treatment system, ammonia delivery system, and air compressor will be by stand-alone programmable logic controller (PLC) systems. These PLCs will include an RS-485 link to the DCS, unless approved otherwise by the Owner, for transfer of process monitoring and status information. Air compressor and dryer packages will utilize their manufacturers' standard stand-alone control system(s) with a data link to the plant DCS. Signals for start/stop, lead/lag, and status (running, trouble, etc.) will be hard wired to/from the DCS unless otherwise provided by the OEM.

A consistent control and instrumentation philosophy will apply throughout the plant to minimize diversity of equipment type and manufacturer.

There will be no hardwired discrete control and monitoring operator stations to back up the LCD's and keyboards. However, individual emergency pushbuttons or switches will be provided for hardwired shutdown of major equipment (CTG, HRSG, STG and fuel gas shut off). These push buttons will be mounted in the Plant Main Control Room.

5.3.1 DCS Equipment

5.3.1.1 Operator Workstation

The balance of plant DCS will include one operator workstation. The workstation will be equipped with one keyboard and one 19" LCD Flat Panel Monitor. The monitor will be located on the work desk provided in the Plant Main Control Room.

5.3.1.2 Printers

One color inkjet printer will be provided and will be located on the work desk in the Plant Main Control Room.

5.3.2 DCS Processors, I/O Cabinets and Hardware

Processors, power supplies, communication modules, input and output modules will be mounted in a freestanding cabinet with front access. Redundant circuits in separate raceways will provide 125 VDC power to the DCS processors. The operator workstation and printer will be powered from the plant UPS system.

The system will be provided with 10 percent spare wired I/O and 10 percent spare slots in each cabinet at system shipment.

Equipment and termination blocks will be identified either with laminated phenolic nameplates or stamped metal tags.

5.3.3 DCS Functionality

The control system will show an overview and grouped or detailed information to assist the operator in required control actions. Functional logic diagrams or ladder logic diagrams will be provided to the DCS supplier.

Motor control logic will be coordinated to offer consistent functionality for all balance of plant equipment. Likewise, the operator interface for such logic will also be consistent. Permissive displays will be provided for applicable motors and valves identifying all system interlocks. Permissive displays will be developed either as a paged display associated with a given graphic or a pop-up display.

All alarm annunciation will be done in the balance of plant DCS. The sequence of events (SOE) function will have a resolution of not more than 1 millisecond and will be an integral part of the DCS. The CTG sequence of events will be synchronized with the same time stamp as the BOP or hard wired points to the BOP DCS to allow comprehensive SOE reports to be generated by the BOP DCS.

5.3.4 Graphics

A maximum of ten process graphics with an ISA-based symbol set, 10 trend displays, and 10 permissive displays that show the status of system interlocks will be included in the

BOP portions of the DCS. Graphic and trend displays associated with the OEM-supplied equipment will be provided. Faceplates will be included as pop-up windows on the process graphic displays. SOE trip logs will be included.

5.3.5 Input/Output

Discrete I/O in the form of analog input/outputs (AI/AO) and digital input/outputs (DI/DO) will be utilized. Pure alarms will open-to-alarm and fail in the open position. Alarms used for control will close-to-alarm and fail in the open position.

Field Wiring

Field wiring to the DCS will land on compression type terminal blocks in the processor or remote I/O cabinets. The DCS will accept both field powered and dry contact inputs. The normal wetting voltage for digital inputs will be 24 VDC supplied by the DCS from redundant power supplies. Motor run/stop status contacts will be 120 VAC powered from the motor control center. Solenoid-operated valves will generally be 120VAC powered from the DCS.

Sequence of Events

One millisecond resolution time stamped points (SOE) will be provided for the following:

Generator circuit breakers (52b contacts)

The 4.16kV volt main breakers to secondary unit substation transformers (4.16kV to 480 volt) (52b contacts)

The 480 volt secondary unit substation main breakers (52b contacts)

All lockout relays combined into a single “protection tripped” signal (normally-open contact)

No other points than those listed above will be connected as SOE

5.3.6 Foreign Device Interface (FDI)

The DCS will be capable of interfacing with other foreign devices through Ethernet, RS232, or RS485 interfaces using a MODBUS or TCP/IP protocol (where applicable). Data links to the DCS will be provided for switchgear relays, fuel gas metering station, ammonia delivery system, CEMS, HRSG, air compressor, and gas compressors. A Serial MODBUS link will be utilized for interfacing to the CT and STG TCP.

5.3.7 Factory Acceptance Test

The DCS will include a supplier-supported factory acceptance test, which will provide a thorough demonstration of all functional features of the DCS. The system will be demonstrated using software simulation, but will include sufficient hardware testing to confirm proper system integration. A test procedure will be developed by the system supplier to support the factory acceptance test.

5.4 Local Controls

DCS start/stop functions will not be provided for self-contained components/equipment packages that do not require constant operator control or intervention (e.g., lubricating oil pumps, sump pumps, vent fans, etc).

Hard wired local controls for equipment will be limited to hand-off-auto switches in the MCC's for 480 volt motors and those provided by the equipment/skid manufacturer.

5.5 Analytical Equipment

5.5.1 Continuous Emissions Monitoring System

A continuous emissions monitoring system (CEMS) and data acquisition and reporting system (DARS) will be provided for the HRSG trains in accordance with the air permit. The CEMS will consist of sampling devices connected via sample lines to emissions rack mounted analytical measurement devices and CEMS control equipment located in the CEMS enclosure near the base of one of the stacks.

Adequate rack space will be provided to allow future analyzers if required.

The building containing the CEMS equipment will have an exterior weather shield to protect the bolted racks, gas cylinders and regulators for connection of the calibration gases.

The CEMS will be controlled by a PLC and will monitor NOx, CO, O_2, and NH_3.

Inputs for fuel flow, power generation, and all other required process conditions will be hard wired from the plant DCS. Emissions will be calculated based on plant fuel flows, analyzer readings, and surrogate calculations based on fuel analysis.

The primary operator interface with the CEMS will be through a personal computer workstation (PC) located in the CEMS building. The PC will provide operator access via a Windows environment to acknowledge alarms, retrieve data, and generate all required emissions reports and will include exceedance/fault codes as appropriate. System reports will be modifiable by site personnel, and emission alarms will be adjustable through the PC interface. All appropriate equations and coefficients used by the systems will be capable of being modified by authorized plant personnel (via password protection).

The CEMS hardware and reporting package software will meet the requirements of applicable permits. System reports will be able to include a daily summary of the average plant generation in megawatts, the average fuel flows, and any other plant data available to the system.

All corrected emissions data and a common alarm will be hard wired to the DCS system.

UPS power will be provided for the CEMS analyzers, controller, and PC to ensure proper surge protection, power conditioning, and protection in the event of a momentary loss of power.

The local control unit located with the CEMS equipment will allow access to the operational status of the CEMS and provide the capability to initiate both automatic and manual calibrations.

5.6 Instrumentation Design Criteria/General Requirements

5.6.1 General

The instrumentation and control equipment/systems and materials and their installation will be designed in accordance with applicable codes, industry standards, this scope document, and material selection specified in this section. Instruments and valves will be pre-calibrated, tagged and/or programmed by the supplier.

Pneumatic signal levels, where used, will be 3-15 psig for pneumatic transmitter outputs, controller outputs, electric-to-pneumatic converter outputs, valve positioner inputs, etc. Signal levels of electric to pneumatic converters may also be 6 to 30 psig, depending on application.

Electronic transmitters and controllers will be designed for proportional output of 4-20 mA DC with 24V DC power supply from the DCS into 600 OHM maximum loop resistance.

No primary sensor full-scale signal level, other than thermocouples, will be less than 10 mV or greater than 125 V. Transmitters requiring an external power supply will be connected to 115 VAC.

An identification tag showing the purchaser's identifying tag number as per the data sheets will be attached to each field instrument. The tag will be a minimum of 20 gage stainless steel wired to the transmitter with a minimum letter height of 0.25", 85 characters maximum or permanently stamped on the instrument with 65 characters maximum. As a minimum the tag should have the manufacturer name, model number and purchase order number. For safety, tag wired ends will be curled.

Each field instrument will be installed as per construction installation drawings. Interchanging instruments during construction is prohibited.

Field instruments, digital indicators, DCS, PLC, etc. will be configured for the following engineering units:

Temperature	Degrees F
Pressure	
Near Atmos.	In. of water
Above Atmos.	PSIG
Below Atmos.	In. of Hg Absolute
Absolute	PSIA
Level	Percent of range for process
Flow	
Liquids	GPM
Water	GPM
Gas or Vapor	SCFH*
Air & Nitrogen	SCFH*
Analyzers	Ph, %, us

* Defined at 60° F and 14.69 PSIA

5.6.2 Pressure Instruments

Where necessary for operation, either industrial-type 4-1/2-inch-diameter pressure gauges with white faces and black scale markings, or indicating pressure transmitters will be provided. Pneumatic receiver gauges will be 3-1/2 inch oval size. In general, pressure instruments will have linear scales with units of measurement in pounds per square inch gauge. Pressure gauge accuracy will be $\pm$0.5 percent of full range per ANSI Specification B40.1, Grade 2A. Pressure instruments will generally have screwed connections. Pressure gauge stem connection will generally be ½" NPT.

Pressure gauges will have either a blowout disk or a blowout back and an acrylic or shatterproof glass face.

Pressure gauges on process piping will generally be visible 10 feet from an operator's normal stance at floor level and will be resistant to plant atmospheres.

Connections to piping or equipment will be in accordance with piping specification and instrument installation details.

Pressure test points will have isolation valves and caps or plugs. Pressure devices on pulsating services will have pulsation dampers.

Fire protection system pressure gauges will be designed in accordance with UL standards.

"Face" gauges in high vibration areas will be liquid filled and include a vibration snubber. "Face" gauges used for measuring high pressure or temperature process media will be fitted with an isolation diaphragm.

5.6.3 Temperature Instruments

In general, temperature instruments will have scales with temperature units in degrees Fahrenheit. Exceptions to this are electrical machinery RTDs and transformer winding temperatures, which are in degrees Celsius.

Dial thermometers will have 4-1/2 inch-diameter (minimum) dials and white faces with black scale markings and will be every-angle type and bimetal actuated. Dial thermometers will generally be visible 10 feet from an operator's normal stance at floor level (viewing area) and will be resistant to plant atmospheres.

Temperature elements and dial thermometers will be protected by thermowells except when measuring gas or air temperatures at atmospheric pressure. Temperature test points will have thermowells and caps or plugs.

Thermowells for dial thermometers and filled system instruments will be purchased with the instruments to assure proper fit. Thermowells will be constructed of stainless steel except where conditions warrant the use of main line class material.

All thermowells will be drilled barstock (not built-up type).

Threaded and socket weld thermowells will have lagging extensions when used with insulation for high temperature. Consideration will be given to thicker insulation in cold services.

In general, RTDs will be dual 100-ohm platinum three-wire circuits (R_{100}/R_0-1.385). The element will be spring-loaded, mounted in a thermowell, and connected to a cast iron head assembly. However, RTDs associated with multi-variable transmitters will be four-wire.

Thermocouples will be type K dual element, ungrounded, and spring-loaded. For general service, the materials of construction will be dictated by service temperatures. Thermocouple heads will be the cast type with an internal grounding screw. If a thermocouple is inaccessible, the leads will be brought to an accessible junction box.

"Face" gauges in high vibration areas will be liquid filled and include a vibration snubber.

5.6.4 Level Instruments

Reflex-glass or magnetic level gauges will be used. Level indication for corrosive service (if required) will use devices other than reflex-glass gauges. Level gauges for high-pressure service will have suitable personnel protection. Transparent type gauge glasses will be used up to 600 PSIG.

Gauge glasses used in conjunction with level instruments will cover a range that includes the highest and lowest trip/alarm set points.

Level transmitters for measuring the level in storage tanks vented to atmosphere (e.g., condensate storage tank) will generally be the flanged differential pressure type and will have local and main control room indication. Differential pressure type level instruments will normally be furnished for pressure vessels in level ranges which exceed 48 inches. External displacer type level transmitters and controllers will be normally furnished for all pressure vessels in level ranges equal to or less than 48 inches. Guided wave, internal displacer or ball float level instruments will be furnished for open sumps and tanks and for services where draining of the tank for maintenance can be easily accomplished.

5.6.5 Flow Instruments

Primary Elements

Concentric type orifice plates will be used as the primary elements for flow measurement. In general, 316 SS orifice plates will be provided. For clean fluids the square edge orifice will be used. The orifice plates will be in accordance with API 2530, Chapter 14, Section 3, orifice metering of natural gas and other related hydrocarbon fluids. Each orifice plate will be stamped with the tag number. For clean fluids use square edge orifices.

The feedwater flow will be measured with a flow nozzle or venturi tube and differential pressure transmitters. The flow signal will be temperature compensated.. The steam flow will be measured with a flow nozzle or venturi tube and will be pressure and temperature compensated.

Meter Runs

Flow nozzle and venturi tubes will be installed in a horizontal line. Orifice runs will utilize orifice flange taps and will be installed in a horizontal line if possible. Integral orifice meters, variable area meters (armored rotameters) should be installed in lines less than 2 inches.

Flow transmitters will be the differential pressure type with the range matching (as closely as practical) the primary element. All flow differential pressure transmitters will be furnished and shipped with integral three or five valve manifolds. In general, flow transmitters will be Rosemount 3095 MV or acceptable equal with external RTDs.

5.6.6 Control Valves

Control valves in throttling service will be the globe-body cage type with body materials, pressure rating, and valve trim suitable for the service involved. Other style valve bodies may also be used when suitable for the intended service. No split-body valves or separable flange styles will be used without specific approval. Butterfly valves will be of the lug body type.

Each control valve will be sized using the methods and equations described in the standard ISA-75.01. Each control valve will be sized and selected, including trim and plug design, actuators, valve materials, and valve accessories to properly satisfy all operating and design conditions of each application as listed in the Data Sheets.

The valve body size will not be less than two pipe sizes smaller than the nominal inlet pipeline size, unless otherwise specified.

Bellow seal bonnets will be used for highly toxic or volatile fluids. Teflon or approved non-asbestos alternate packing material may be used for temperatures between -40°F and 450°F. Grafoil packing will be used as a minimum for temperatures 450°F and above.

Solenoid valves supplied with the control valves will have Class H coils 120 VAC UPS powered. The coil enclosure will normally be a minimum of NEMA 4 but will be suitable for the area of installation. Terminations will typically be by pigtail wires.

5.6.6.1 End Connections

Steel valves with flanged ends will be in accordance with ASME B16.5. End to end dimension of each valve will be in accordance with the appropriate ISA Standards (i.e. ISA S75.03 and S75.04).

All welding connections for valves 2-1/2 inches and larger in nominal size will be butt-welded. All welding connections for valves 2 inches and smaller in nominal size will be socket welded. All welding ends will be in accordance with ASME B16.34 and B16.25.

Control valves in 300# class service and below will be flanged, except for Hydrogen, Natural Gas, Ammonia, steam and vacuum service. Where flanged valves are used the flange rating will match the pipe class specifications.

All control valves 600# and greater will be furnished with weld end connections.

For butterfly, ball, and similar body types, lugged or flanged bodies to permit dead end service will be provided unless otherwise specified. Wafer types that cannot be independently fastened to the field piping at both ends of the valve body will not be provided.

5.6.6.2 End extensions and Reducers:

If the size of a welded end valve is different than the field pipe size, the valve will be furnished with shop welded concentric reducers matching the upstream and downstream pipe size, material and wall thickness. Shop welded end extensions will be provided for valves with body material that is different than the field piping material (such as alloy valve bodies to be welded into carbon steel pipelines or vice versa). End extensions will be a pipe section at least 6 inches (150 mm) long. End extensions and reducers will be factory installed on the valve body and stress relieved in accordance with ASME B31.1. End extensions and reducers will be shown on the valve drawing and included in the shop end-to-end or center-to-face dimensions.

5.6.6.3 Valve Actuators

All control valves will be furnished with pneumatic spring opposed diaphragm actuators where possible. Pneumatic piston, electric or other actuators can be provided if better suited for the application or called out on the data sheets.

Valves will be designed to fail in a safe position.

Valve actuators with valve action "fail open" or "fail closed", will be provided with a mechanical spring or a trip valve and volume tank to fully open or close the valve as applicable on loss of air pressure. Valve actuators with valve action "fail in place" will be provided with a mechanism to hold the valve in position on loss of air pressure. Actuators will be sized sufficiently to achieve the desired “fail” position while the valve is operating at maximum differential pressure.

5.6.6.4 Volume Tanks

Volume tanks will be designed to withstand a minimum pressure of 125 psig.

All volume tanks will be constructed in accordance with ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 (stamped UM).

5.6.6.5 Sound Control Requirements

For all valves, the equivalent "A" weighted sound level, measured three feet downstream of the valve outlet and one meter from the un-insulated pipe surface, will not exceed 85 dBA unless noted otherwise on the valve Data Sheets. Noise reduction will be accomplished by source treatment, utilizing trim specifically designed for the service. Calculations of noise will be done in accordance with the International Standard IEC 534-8-3 and submitted with valve specifications and sizing information.

5.6.6.6 Positioners

Positioners will be the Fisher DVC6000 Series, electro-pneumatic type utilizing the HART communication protocol and will be provided with pressure gauges for indicating the air supply, valve actuator, and control signal pressures. Input signal will be loop powered by the DCS. Positioners will be designed for a control signal input range of 4-20 mA. Positioners will provide an output signal from 0 psig to the full supply air pressure to the valve actuator. Positioners will not be provided with bypasses.

Control valve accessories will be mounted on the valve actuator unless severe vibration is expected. Control valves with a positioner will not be equipped with a pneumatic valves unloader.

When valve position feed back is required for DCS information (i.e. non-control use) only, Fisher digital valve controllers (DVC’s) will be utilized to provide a Hart signal back to the

DCS superimposed on the valve analog output. Valve position feed back for process control use will be hard wired.

5.6.7 Instrument Tubing and Installation

Tubing used to connect instruments to the process line will generally be 1/2 inch diameter, 0.049 inch wall (minimum) seamless 316 stainless steel for primary instruments and sampling systems.

Instrument tubing fittings will be the compression type. One manufacturer will be selected for use and will be standardized as much as practical throughout the plant.

Differential pressure (flow) instruments will be fitted with five-valve manifolds. Three-valve or two-valve manifolds will be specified for other instruments as appropriate.

Instrument installation will be designed to correctly sense the process variable. Taps on process lines will be located so that sensing lines do not trap air in liquid service or liquid in gas service. Taps on process lines will be fitted with a shutoff (root or gauge valve) close to the process line. Root and gauge valves will be main-line class valves.

Instrument tubing will be supported in both horizontal and vertical runs as necessary. Expansion loops will be provided in tubing runs subject to high temperatures. The instrument tubing support design will allow for movement of the main process line.

5.6.8 Field-Mounted Instruments

Field-mounting instruments will be of a design suitable for the area in which they are located. They will be mounted in areas accessible for maintenance and relatively free of vibration and will not block walkways or prevent maintenance of other equipment.

Field-mounted instruments will be grouped on racks. Supports for individual instruments will be a prefabricated, off-the-shelf, 2-inch pipe stand. Instrument racks and individual supports will be mounted to concrete floors, to platforms, or on support steel in locations not subject to excessive vibration.

Instruments will be freeze protected by utilizing heated “hard box” type enclosures as required.

Individual field instrument sensing lines will be sloped or pitched in such a manner and be of such length, routing, and configuration that signal response is not adversely affected.

Liquid level controllers will generally be the non-indicating, displacement type with external cages.

5.6.9 Instrument Air System

Branch headers will have a shutoff valve at the takeoff from the main header. The branch headers will be sized for the air usage of the instruments served, but will be no smaller than 3/8 inch. Each instrument air user will have a shutoff valve, filter, and regulator (where appropriate) at the instrument.

Appendix C
Revised Air Quality Section

5.1 Air Quality

The Lodi Energy Center (LEC) will be a combined-cycle nominal 296~~255~~ megawatt (MW) (nominal) power generation facility consisting of a Siemens STG 6-5000F ~~"Rapid Response" GE Energy Frame 7FA,~~ natural gas-fired turbine-generator in a "Flex Plant™ 30" configuration;~~,~~ a single condensing steam turbine (STG);~~,~~ a 7-cell cooling tower;~~,~~ and associated balance-of-plant equipment. The facility will be located in Lodi, San Joaquin County, California, on a 4.4-acre parcel located adjacent to the City of Lodi's White Slough Water Pollution Control Facility (WPCF) and the existing Northern California Power Agency (NCPA) Combustion Turbine Project #2 (STIG plant).

This section describes existing air quality conditions, maximum potential impacts from the project, and mitigation measures that keep these impacts below thresholds of significance. The project will use clean and efficient combined-cycle generation technology to generate electricity in a manner that will minimize the amount of fuel needed, emissions of criteria pollutants, and potential effects on ambient air quality.

Other beneficial environmental aspects of the project that minimize adverse air quality impacts include the following:

- Clean-burning natural gas as fuel
- Selective catalytic reduction (SCR) and dry low NO_x combustors to minimize NO_x emissions
- Oxidation catalyst to reduce carbon monoxide emissions
- Faster-starting "Flex Plant™ 30" technology to minimize gas turbine startup times and reduce startup emissions
- Inlet air filters and lube oil vent filters to minimize particulate emissions
- Appropriately sized stack to reduce ground-level concentrations of exhaust constituents

This section presents the methodology and results of the air quality analyses performed to assess potential impacts associated with air emissions from the construction and operation of the project. Potential public health risks posed by emissions of non-criteria pollutants are addressed in Section 3~~5~~.9 (Public Health) of Supplement D.

Section 5.1.1 describes the affected environment. Section 5.1.2 provides a detailed description of the project. Section 5.1.3 provides an evaluation of emissions from the proposed project, while Section 5.1.4 discusses the best available control technology determination. Section 5.1.5 describes the air quality impact analysis and mitigation measures. Section 5.1.6 presents applicable laws, ordinances, regulations, and standards (LORS). Section 5.1.7 presents agency contacts, permit requirements and schedules. Section 5.1.8 contains references cited or consulted in preparing this section.

5.1.1 Affected Environment

5.1.1.1 Geography and Topography

The project site is within a 1,040-acre parcel owned by and incorporated in the City of Lodi. This incorporated parcel is not contiguous with the City of Lodi, which is approximately 6 miles to the east. The proposed site parcel is approximately 4.4 acres adjacent to the City of Lodi's White Slough WPCF to the east, treatment and holding ponds associated with the WPCF to the north, the existing STIG plant to the west, and a vector control facility to the south. Also south of the project site is Dredger Cut, which discharges into White Slough at the confluence with Bishop Cut.

The project site is nearly level, at an elevation approximately at sea level. Essentially flat terrain extends for many miles on all sides of the project site. The project site is located in the San Joaquin Valley Air Pollution Control District (SJVAPCD).

5.1.1.2 Climate and Meteorology

The climate of the San Joaquin Valley is characterized by hot summers, mild winters, and small amounts of precipitation. The major climatic controls in the Valley are the mountains on three sides and the semi-permanent Pacific High pressure system over the eastern Pacific Ocean. The Great Basin High pressure system to the east also affects the Valley, primarily during the winter months. These synoptic scale influences result in distinct seasonal weather characteristics, as discussed below.

The Pacific High is a semi-permanent subtropical high-pressure system located off the Pacific Coast. It is centered between the 140°W and 150°W meridians, and oscillates in a north-south direction seasonally. During the summer, it moves northward and dominates the regional climate, producing persistent temperature inversions and a predominantly southwesterly wind field. Clear skies, high temperatures, and low humidity characterize this season. Very little precipitation occurs during summer months, because migrating storm systems are blocked by the Pacific High. Occasionally, however, tropical air moves into the area and thunderstorms may occur over the adjacent mountains.

In the fall, the Pacific High weakens and shifts southwestward toward Hawaii, and its dominance is diminished in the San Joaquin Valley. During the transition period, the storm belt and zone of strong westerly winds also moves southward into California. The prevailing weather patterns during this time of year include storm periods with rain and gusty winds, clear weather that can occur after a storm or because of the Great Basin High pressure area, or persistent fog caused by temperature inversion.

Precipitation and temperature data have been recorded at the meteorological monitoring station located in Lodi, approximately 5.7 miles east-northeast of the project site. In summer (June, July, and August), daily high and low temperatures at the project area average 89.7 and 55.0°F (degrees Fahrenheit), respectively. In winter (December, January, and February), daily high and low temperatures are about 56.6 and 38.8°F, respectively.[1] The average annual rainfall at the project site is about 17.6 inches, of which about 81% occurs between November and March. Between rainstorms, skies are fair, winds are light, and temperatures are moderate.

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1 Desert Research Institute, Western Regional Climate Center. 2008. Western U.S. Climate Historical Summaries, Site Accessed May 2008. URL: http://www.wrcc.dri.edu/Climsum.html

Air quality is determined primarily by the type and amount of pollutants emitted into the atmosphere, the topography of the air basin, and local meteorological conditions. In the project area, stable atmospheric conditions and light winds can provide conditions for pollutants to accumulate in the air basin when emissions are produced. The predominant winds in California are shown in Appendix 5.1B, Figures 5.1B-1A through 5.1B-1D. As indicated in the figures, winds in California generally are light and easterly in the winter, but strong and westerly in the spring, summer, and fall.

Wind speed and wind direction data have been recorded at the meteorological monitoring station at the Stockton Metropolitan Airport. This station is located approximately 16 miles to the south-southeast, and is considered representative of meteorological conditions in the project area. Quarterly wind roses and wind frequency distribution tables are provided in Appendix 5.1B. Wind patterns at the project site can be seen in Appendix 5.1B, Figures 5.1B-2A through 5.1B-6E, which show quarterly and annual wind roses for meteorological data collected at the Stockton Metropolitan Airport meteorological station during 2000 through 2004. The annual wind rose for 2004 is typical for this location and is shown as Figure 5.1-1. It can be seen that the winds are mild (12.8 percent calm conditions) and predominantly from the northwestern quadrant. On an annual basis, approximately 57.6 percent of the winds come from the west through north-northwest. Winds are predominantly from the northwest and southeast during the first quarter, from the west during the second quarter, from the northwest during the third quarter, and from the southeast during the fourth quarter. Southeasterly winds develop mainly during the first and fourth quarters and are essentially absent during the other quarters.

The mixing heights of the area are affected by the eastern Pacific high-pressure system and marine influences. Often, the base of the inversion is found at the top of a layer of marine air, because of the cooler nature of the marine environment. Smith, et al, (1984) reported that at Oakland, the nearest upper-level meteorological station (located approximately 50 miles west-southwest of the project site), 50th percentile morning mixing heights for the period 1979–80 were on the order of 1,770 feet (530 to 550 meters) in summer and fall, and 3,600 to 3,900 feet (1,100 to 1,200 meters) in winter and spring. The 50th percentile afternoon mixing heights ranged from 2,150 and 3,030 feet (660 to 925 meters) in summer and fall, and over 3,900 feet (over 1200 meters) in winter and spring. Such mixing heights provide generally favorable conditions for the dispersion of pollutants. Inland areas, where the marine influence is weaker, often experience strong ground-based inversions during cold weather periods. These inversions inhibit dispersion of low-lying sources of air pollution, such as cars, trucks and buses, and can result in high pollutant concentrations.

5.1.1.3 Criteria Pollutants and Air Quality Trends

5.1.1.3.1 State and National Air Quality Standards

The U.S. Environmental Protection Agency (EPA) has established national ambient air quality standards (NAAQS) for ozone, nitrogen dioxide (NO_2), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter with aerodynamic diameter less than or equal to 10 microns (PM_{10}), particulate matter with aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$), and airborne lead. In addition, the California Air Resources Board (CARB) has established standards for ozone, CO, NO_2, SO_2, sulfates, PM_{10}, airborne lead, hydrogen sulfide, and vinyl chloride at levels designed to protect the most sensitive members of the population, particularly children, the elderly, and people who suffer from lung or heart diseases. Areas with air pollution levels above these standards can be considered "nonattainment areas" subject to planning and pollution control requirements that are more stringent than standard requirements. The attainment status of the San Joaquin Valley air basin with respect to federal and state standards is summarized in Table 5.1-1.

Both state and national air quality standards consist of two parts: an allowable concentration of a pollutant, and an averaging time over which the concentration is to be measured. Allowable concentrations are based on the results of studies of the effects of the pollutants on human health, crops and vegetation, and, in some cases, damage to paint and other materials. The averaging times are based on whether the damage caused by the pollutant is more likely to occur during exposures to a high concentration for a short time (one hour, for instance), or to a relatively lower average concentration over a longer period (8 hours, 24 hours, or 1 month). For some pollutants there is more than one air quality standard, reflecting both short-term and long-term effects. Table 5.1-2 presents the NAAQS and California ambient air quality standards for selected pollutants. The California standards are generally set at concentrations much lower than the federal standards and in some cases have shorter averaging periods.

TABLE 5.1-1
San Joaquin Valley Attainment Status

Pollutant		California [a]	National [b]
Ozone	1 hour	Nonattainment/Severe	No Federal Standard
	8 hours	Nonattainment	Nonattainment/Serious[e]
Carbon Monoxide		Attainment/Unclassified	Attainment/Unclassified
Nitrogen Dioxide		Attainment	Attainment/Unclassified
Sulfur Dioxide		Attainment	Attainment/Unclassified
Suspended Particulate Matter (10 Microns)		Nonattainment	Nonattainment/Serious[c]
Suspended Particulate Matter (2.5 Microns)		Nonattainment[d]	Nonattainment
Sulfates		Attainment	No Federal Standard
Lead		Attainment	No Designation/Classification
Hydrogen Sulfide		Unclassified	No Federal Standard
Vinyl Chloride		Attainment	No Federal Standard

[a]CCR Title 17, Sections 60200-60210

[b]40 CFR Part 81

[c]~~Although~~ EPA ~~has~~ determined that the San Joaquin Valley Air Basin has attained the federal PM10 standards (71 FR 63641; October 30, 2006) and redesignated ~~, its determination does not constitute a redesignation to attainment per section 107(d)(3) of the federal Clean Air Act. EPA has proposed to redesignate~~ the San Joaquin Valley Air Basin as attainment for PM10 ~~(73 FR 22307; April 25, 2008), but this proposal has not become final because the public comment period just ended on June 10, 2008 (73 FR 30029)~~ effective December 12, 2008 .

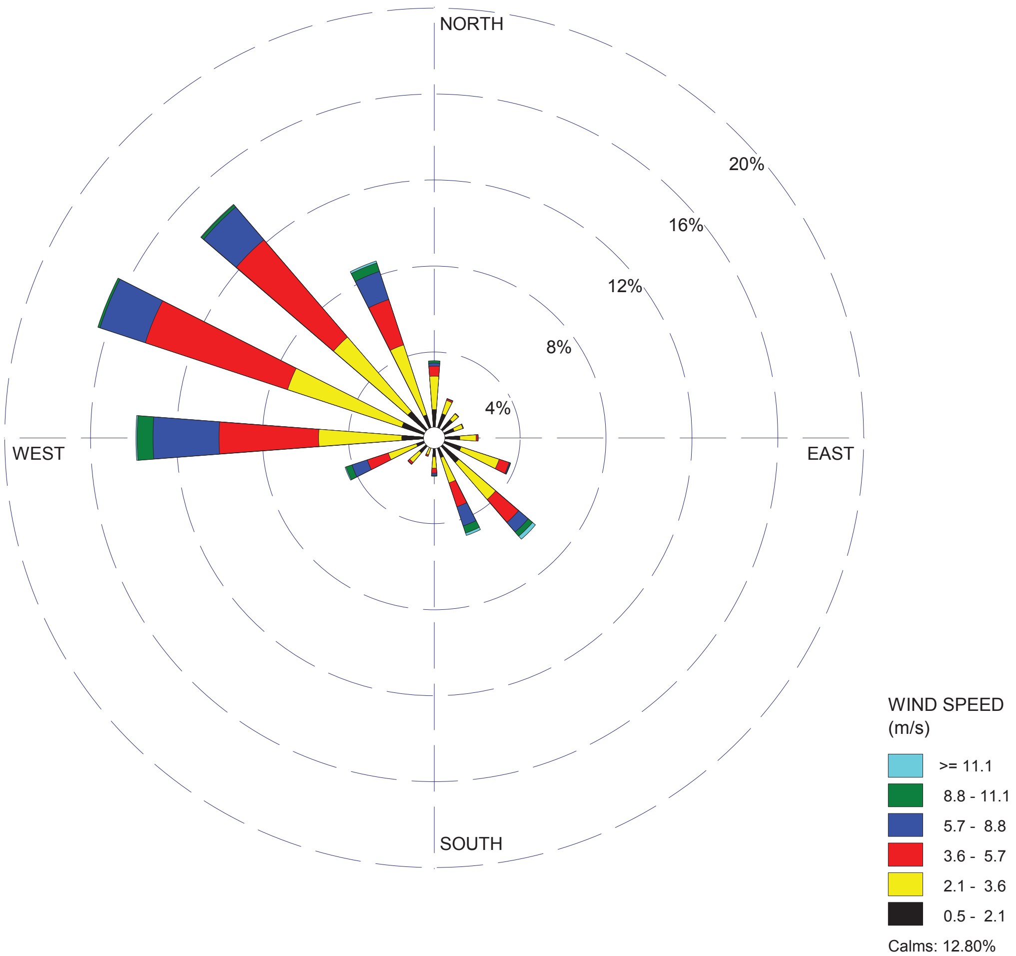
[d]The Valley is designated nonattainment for the 1997 PM2.5 federal standards. EPA designations for the 2006 PM2.5 standards will be finalized in December 2009. SJVAPCD has determined, based on the 2004-06 PM2.5 data, that the Valley has attained the 1997 24-hour PM2.5 standard.

[e]On April 30, 2007, the Governing Board of SJVAPCD voted to request EPA to reclassify the San Joaquin Valley Air Basin as extreme nonattainment for the federal 8-hour ozone standard. The California Air Resources Board, on June 14, 2007, approved this request. This request has been forwarded to EPA by the California Air Resources Board and would become effective upon EPA final rulemaking after a notice and comment process; it is not yet in effect.

WIND ROSE PLOT:

Stockton, CA - 2004
January 1, 2004 through December 31, 2004

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:

DATA PERIOD:
2004
Jan 1 - Dec 31
00:00 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:
12.80%

TOTAL COUNT:
8398 hrs.

AVG. WIND SPEED:
3.52 m/s

DATE:
5/1/2008

PROJECT NO.:

WRPLOT View - Lakes Environmental Software

FIGURE 5.1-1
2004 ANNUAL WIND ROSE,
STOCKTON, CALIFORNIA
LODI ENERGY CENTER
LODI, CALIFORNIA

CH2MHILL

TABLE 5.1-2
Ambient Air Quality Standards

Pollutant	Averaging Time	California	National
Ozone	1 hour	0.09 ppm	—
	8 hours	0.070 ppm	0.075 ppm
Carbon Monoxide	8 hours	9 ppm	9 ppm
	1 hour	20 ppm	35 ppm
Nitrogen Dioxide	Annual Average	0.030 ppm	0.053 ppm
	1 hour	0.18 ppm	—
Sulfur Dioxide	Annual Average	—	0.03 ppm (80 μg/m^3)
	24 hours	0.04 ppm (105 μg/m^3)	0.14 ppm (365 μg/m^3)
	3 hours	—	0.5 ppm (1300 μg/m^3)*
	1 hour	0.25 ppm (655 μg/ m^3)	—
Suspended Particulate Matter (10 Micron)	24 hours	50 μg/m^3	150 μg/m^3
	Annual Arithmetic Mean	20 μg/m^3	—
Suspended Particulate Matter (2.5 Micron)	Annual Arithmetic Mean	12 μg/m^3	15 μg/m^3 (3-year average)
	24 hours	none	35 μg/m^3 (3-year average of 98th percentiles)
Sulfates	24 hours	25 μg/m^3	—
Lead	30 days	1.5 μg/m^3	—
	Calendar Quarter	—	1.5 μg/m^3
Hydrogen Sulfide	1 hour	0.03 ppm	—
Vinyl Chloride	24 hours	0.01 ppm	—
Visibility Reducing Particles	8 hours (10 a.m. to 6 p.m. PST)	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70 percent.	—

*This is a national secondary standard, which is designed to protect public welfare.

ppm = parts per million
μg/m^3= micrograms per cubic meter

5.1.1.3.2 Ambient Monitoring Stations

Data from two ambient air monitoring stations were used to characterize air quality at the project site. They were chosen because of their proximity to the site and because they record area-wide ambient conditions rather than the localized impacts of any particular facility. All ambient air quality data presented in this section were taken from CARB publications and data sources or EPA air quality data tables. Ambient concentrations of ozone, carbon monoxide (CO), nitrogen dioxide (NO_2), respirable particulate matter (PM_{10}), fine particulate matter ($PM_{2.5}$), sulfates, and lead are recorded at the Hazelton Avenue monitoring station in

Stockton, about 3.6 miles from the project site. The nearest monitoring station for SO_2 is at Bethel Island, about 15 miles from the project site. Monitoring of lead ended in 2003. The Stockton-Hazelton monitoring station is operated by the California Air Resources Board and the Bethel Island monitoring station is operated by the Bay Area AQMD.

5.1.1.3.3 Ozone

Ozone is an end-product of complex reactions between volatile organic compounds (VOC) and NO_x in the presence of intense ultraviolet radiation. VOC and NO_x emissions from millions of vehicles and stationary sources, in combination with daytime wind flow patterns, mountain barriers, a persistent temperature inversion, and intense sunlight result in high ozone concentrations. For purposes of state and federal air quality planning, the San Joaquin Valley Air Basin is a nonattainment area for ozone.

Maximum ozone concentrations at the Stockton-Hazelton monitoring station are usually recorded during the summer months. Table 5.1-3 shows the annual maximum one-hour and eight-hour ozone levels recorded at this station in Stockton during the period from 1998–2007, as well as the number of days in which the state and federal standards were exceeded. The data show that the state ozone air quality standard was frequently exceeded during all years except in 2007. The federal 8-hour standard was also exceeded from time to time in six of the 10 years shown.

The long-term trends of maximum one-hour ozone readings are shown in Figure 5.1-2 for the Stockton-Hazelton monitoring station in Stockton. The data show that compliance with the state ozone air quality standards has not been achieved in the area in the past 13 years. Trends of maximum and 3-year averages of the 4th highest daily concentrations of 8-hour average ozone readings[2] at the Stockton-Hazelton station are shown in Figure 5.1-3. These levels are above the new 2008 federal 8-hour average standard (0.075 $\mu g/m^3$) during the 11 years shown (1997-2007), except during period 2002-2005 for the 3-year average of the 4th highest daily concentration.

TABLE 5.1-3
Ozone Levels at Stockton-Hazelton, Stockton, 1998-2007, (parts per million)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Highest 1-Hour Average	0.126	0.114	0.107	0.103	0.102	0.104	0.096	0.099	0.109	0.093
Highest 8-Hour Average	0.100	0.108	0.080	0.088	0.081	0.088	0.080	0.086	0.092	0.081
Number of Exceeding:										
State Standard (0.09 ppm, 1-hour)	10	6	4	5	2	3	1	3	6	0
Federal Standard (0.08 ppm, 8-hour)	4	4	0	1	0	1	0	1	3	0

Source: California Air Quality Data, Annual Summary, California Air Resources Board

Note: The 1997 federal ozone standard has been replaced by the new 2008 standard of 0.075 ppm. A EPA final rule on the ozone standard became effective May 27, 2008.

[2] The federal 8-hour ozone standard is based on this statistic.

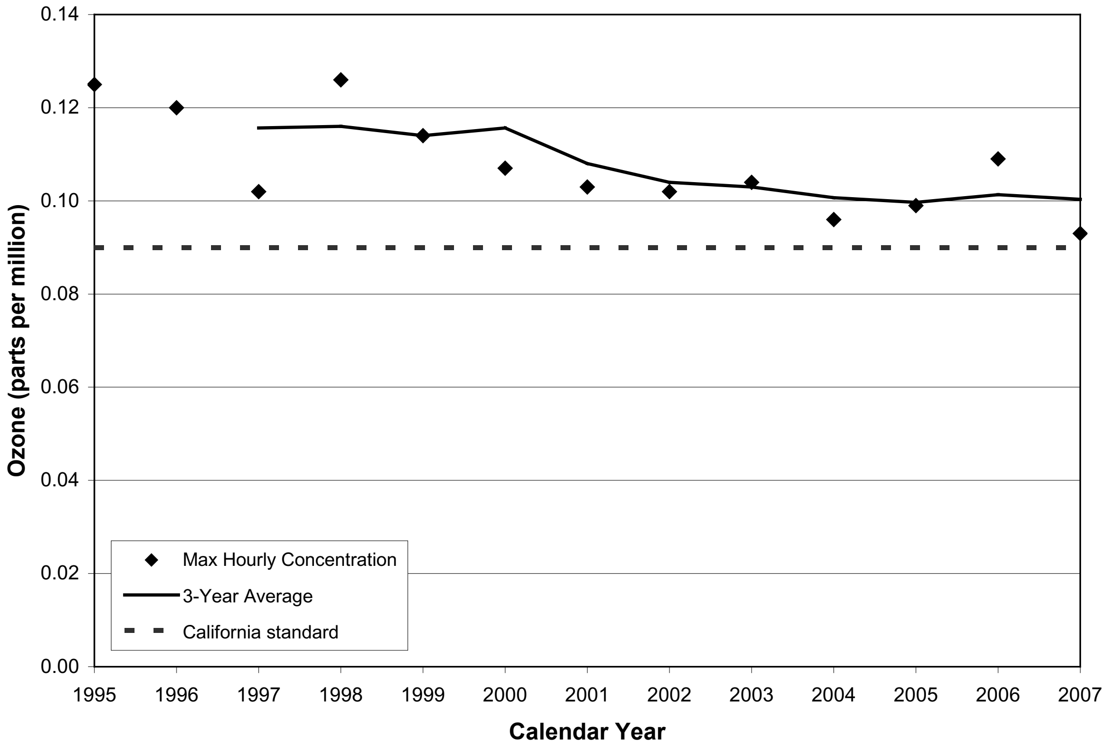


FIGURE 5.1-2
Maximum 1-hour Ozone Level: Stockton-Hazelton: 1995-2007

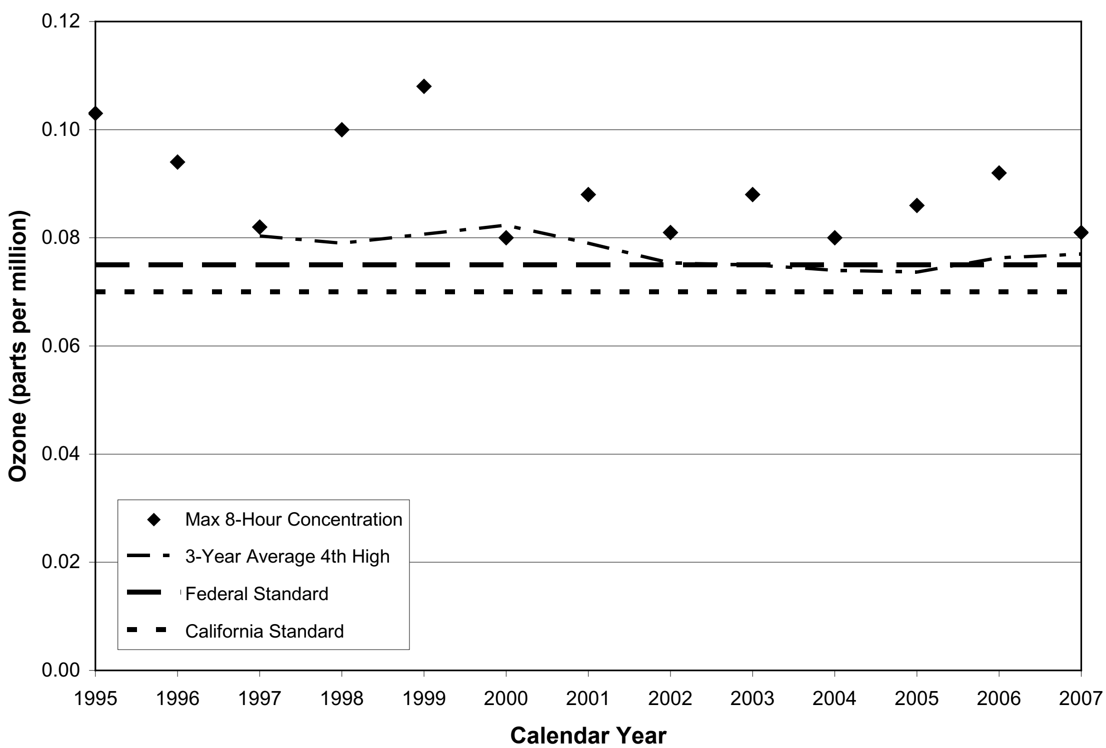


FIGURE 5.1-3
Maximum 8-hour Ozone Level: Stockton-Hazelton: 1995-2007

5.1.1.3.4 Nitrogen Dioxide

Atmospheric NO_2 is formed primarily from reactions between nitric oxide (NO) and oxygen or ozone. NO is formed during high temperature combustion processes, when the nitrogen and oxygen in the combustion air combine. Although NO is much less harmful than NO_2, it can be converted to NO_2 in the atmosphere within a matter of hours, or even minutes, under certain conditions. For purposes of state and federal air quality planning, the San Joaquin Valley Air Basin is in attainment for NO_2.

Table 5.1-4 shows the annual maximum one-hour NO_2 levels recorded at the Stockton-Hazelton monitoring station in Stockton from 1998 through 2007, as well as the annual average level for each of those years. During this period, there have been no violations of either the state 1-hour standard (0.18 ppm) or the federal annual average standard (0.053 ppm). Figure 5.1-4 shows the trend from 1995 through 2007 of maximum 1-hour NO_2 levels at Stockton. These levels have been well below the state standard for many years.

TABLE 5.1-4
Nitrogen Dioxide Levels at Stockton-Hazelton, Stockton, 1998-2007, (parts per million)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Highest 1-hour Average	0.102	0.106	0.099	0.084	0.076	0.088	0.079	0.087	0.072	0.070
Annual Average	0.023	0.024	0.021	0.019	0.021	0.018	0.017	0.017	0.018	0.016
Number of Exceeding:										
State Standard (days) (0.18 ppm, 1-hour)	0	0	0	0	0	0	0	0	0	0
Federal Standard (years) (0.053 ppm, annual)	0	0	0	0	0	0	0	0	0	0

Source: California Air Quality Data, Annual Summary, California Air Resources Board, and AIRData, EPA

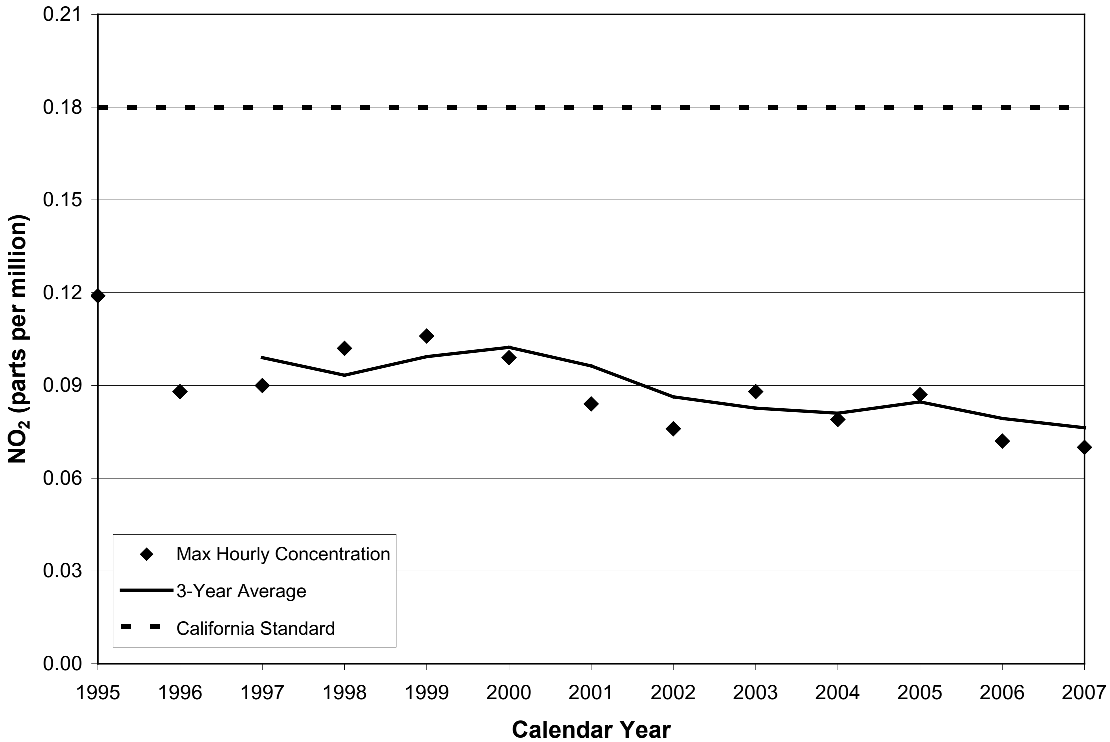


FIGURE 5.1-4
Maximum 1-hour NO_2 Level: Stockton-Hazelton: 1995-2007

5.1.1.3.5 Carbon Monoxide

CO is a product of incomplete combustion, principally from automobiles and other mobile sources of pollution. In many areas of California, CO emissions from wood-burning stoves and fireplaces can also be measurable contributors to high ambient levels of CO. Industrial sources typically contribute less than 10 percent of ambient CO levels. Peak CO levels occur typically during winter months, due to a combination of higher emission rates and stagnant weather conditions. For purposes of state and federal air quality planning, the San Joaquin Valley Air Basin is classified as being in attainment for CO.

Table 5.1-5 shows the California and federal air quality standards for CO, and the maximum 1-hour and 8-hour average levels recorded at the Stockton-Hazelton monitoring station in Stockton during the period 1998–2007.

Trends of maximum 8-hour and 1-hour average CO, shown in Figures 5.1-5 and 5.1-6, respectively, demonstrate that maximum ambient CO levels at Stockton have been below the state and federal standards since 1995.

TABLE 5.1-5
Carbon Monoxide Levels at Stockton-Hazelton, Stockton, 1998-2007, (parts per million)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Highest 8-hour average	7.2	5.3	3.9	6.0	3.2	3.1	2.5	2.9	2.3	2.3
Highest 1-hour average	8.9	8.3	6.5	8.4	6.0	5.8	3.7	4.3	4.4	3.6
Number of days exceeding:										
State Standard (20 ppm, 1-hr)	0	0	0	0	0	0	0	0	0	0
State Standard (9.0 ppm, 8-hr)	0	0	0	0	0	0	0	0	0	0
Federal Standard (35 ppm, 1-hr)	0	0	0	0	0	0	0	0	0	0
Federal Standard (9 ppm, 8-hr)	0	0	0	0	0	0	0	0	0	0

Source: California Air Quality Data, Annual Summary, California Air Resources Board, and AIRData, EPA

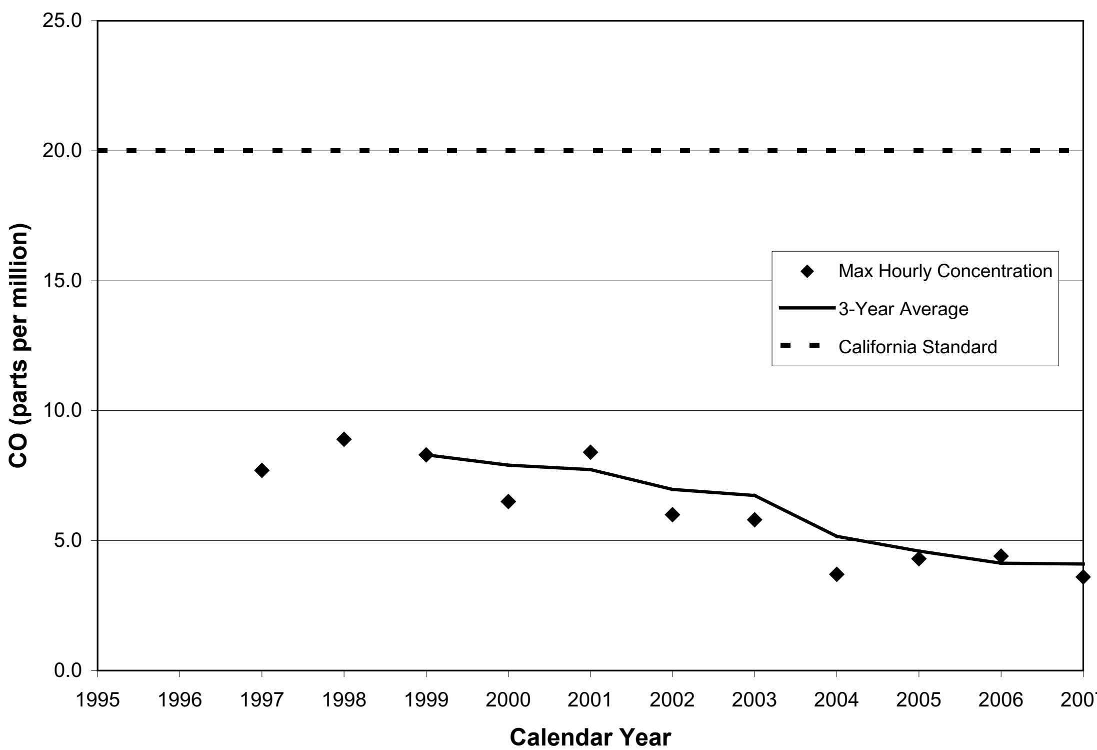


FIGURE 5.1-5
Maximum 1-hour Average CO Level: Stockton-Hazelton: 1997-2007

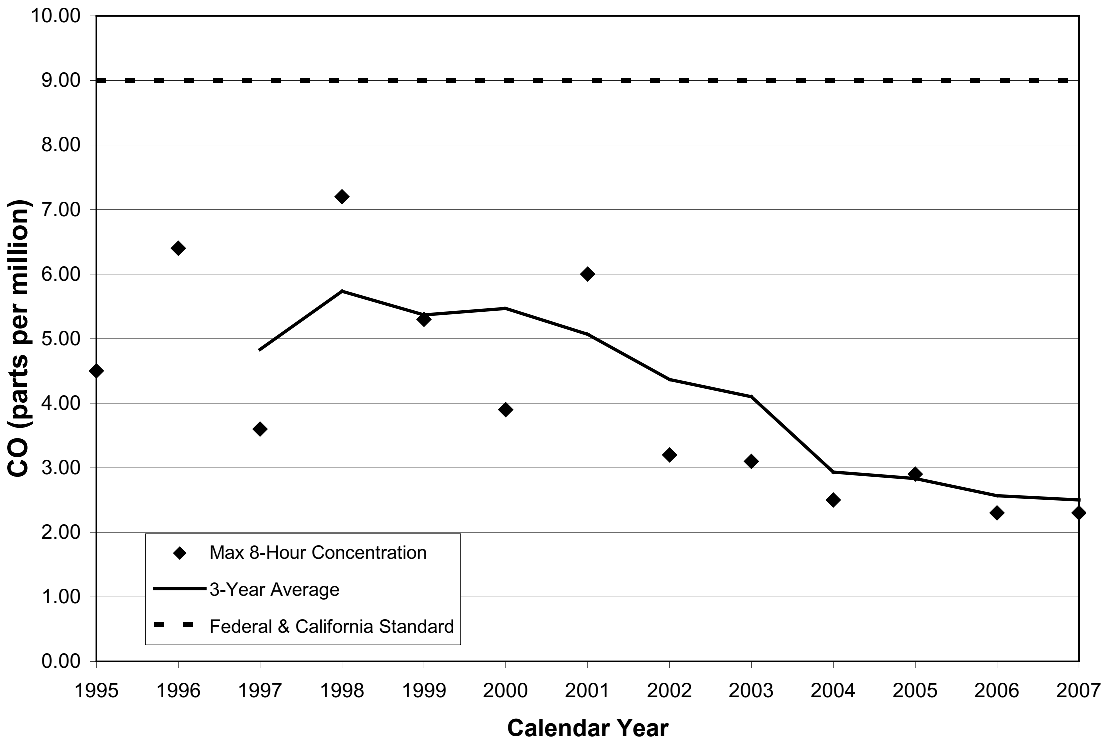


FIGURE 5.1-6
Maximum 8-hour Average CO Level: Stockton-Hazelton: 1995-2007

5.1.1.3.6 Sulfur Dioxide

SO_2 is produced when any sulfur-containing fuel is burned. It is also emitted by chemical plants that treat or refine sulfur or sulfur-containing chemicals. Natural gas contains negligible sulfur, while fuel oils contain much larger amounts. Because of the complexity of the chemical reactions that convert SO_2 to other compounds (such as sulfates), peak concentrations of SO_2 occur at different times of the year in different parts of California, depending on local fuel characteristics, weather, and topography. The San Joaquin Valley Air Basin is considered to be in attainment for SO_2 for purposes of state and federal air quality planning.

Table 5.1-6 presents the state and federal air quality standards for SO_2 and the maximum levels recorded at Bethel Island Road (the nearest SO_2 monitoring station) from 1998 through 2007. Maximum 1-hour average and 24-hour average readings have been an order of magnitude below the state standard. The federal annual average standard is 0.03 ppm; during most of the period shown, annual average SO_2 levels at this site have been less than one-tenth of the federal standard. Figure 5.1-7 shows that for several years the maximum SO_2 levels generally have been less than one-fourth of the state standard.

TABLE 5.1-6
Sulfur Dioxide Levels at Bethel Island, 1998–2007 (parts per million)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Highest 1-Hour Average	0.028	0.029	0.018	0.015	0.029	0.016	0.015	0.017	0.017	0.018
Highest 24-hour Average	0.009	0.008	0.007	0.007	0.009	0.006	0.006	0.006	0.007	0.005
Annual Average	0.002	0.002	0.002	0.002	0.003	0.002	0.002	0.002	0.002	0.002
Number of Exceedances:										
Federal Standard										
(0.14 ppm, 24-hour) (days)	0	0	0	0	0	0	0	0	0	0
(0.03 ppm, annual) (years)	0	0	0	0	0	0	0	0	0	0

Source: AIRData, EPA

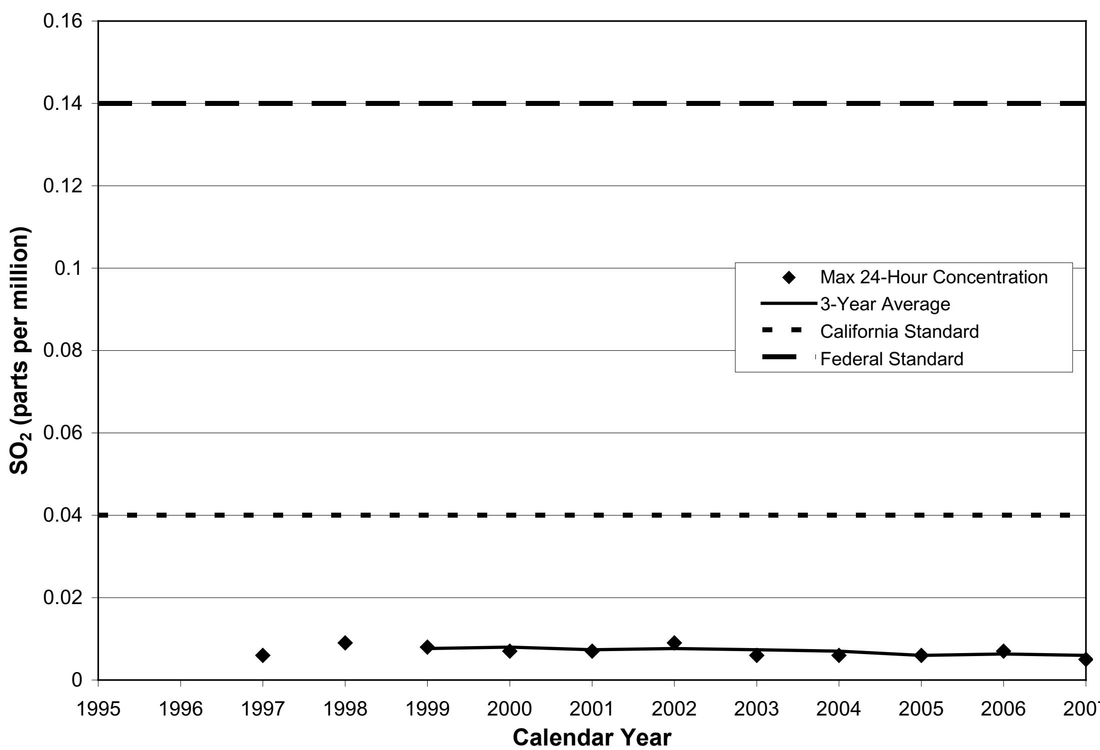


FIGURE 5.1-7
Maximum 24-hour Average SO2 Level: Bethel Island Road: 1997-2007

5.1.1.3.7 Particulate Sulfates

Particulate sulfates are the product of further oxidation of SO_2. The San Joaquin Valley Air Basin is in attainment of the state standard for sulfates (24-hour average < 25μg/m^3). There is no federal standard for sulfates.

Due to extremely low ambient levels, sulfates have not been monitored in San Joaquin County at least since 1990. Table 5.1-7 presents maximum 24-hour average sulfate levels recorded in Bakersfield, the monitoring station closest to the project site, for the period 1995-2002, after which sulfate monitoring ceased at that station. During the period 1995-2002, sulfate levels in Bakersfield have been only about 17 percent of the state standard.

TABLE 5.1-7
Particulate Sulfate Levels in Bakersfield, 1995–2002 (micrograms per cubic meter)

	1995	1996	1997	1998	1999	2000	2001	2002
Highest 24-hour Average	4.3	3.5	3.5	3.5	3.7	3.7	3.6	3.9
Number of Days Exceeding State Standard (25 µg/m3, 24-hour)	0	0	0	0	0	0	0	0

Source: California Air Quality Data, Annual Summary, California Air Resources Board

5.1.1.3.8 Fine Particulates (PM_{10} and $PM_{2.5}$)

Particulates in the air are caused by a combination of wind-blown fugitive dust; particles emitted from combustion sources (usually carbon particles); and organic, sulfate, and nitrate aerosols formed in the air from emitted hydrocarbons, sulfur oxides, and nitrogen oxides. In 1984, the CARB adopted standards for fine particulates (PM_{10}), and phased out the total suspended particulate (TSP) standards that had previously been in effect. PM_{10} standards were substituted for TSP standards because PM_{10} corresponds to the size range of inhalable particulates related to human health. In 1987, EPA also replaced national TSP standards with PM_{10} standards. For air quality planning purposes, the San Joaquin Valley Air Basin is considered to be an attainment area for federal PM_{10} standards and ~~in~~ nonattainment ~~of both federal and~~for state PM_{10} standards.

Table 5.1-8 shows the federal and state air quality standards for PM_{10}, maximum levels, and arithmetic annual averages recorded at Stockton-Hazelton in Stockton from 1998 through 2007. Maximum 24-hour PM_{10} levels from this site frequently exceed the state standards, but have not exceeded the federal standard. Annual average PM_{10} levels are above the state standard during the monitoring period.

The trend of maximum 24-hour average PM_{10} levels is plotted in Figure 5.1-8, and the trend of estimated violations of the state 24-hour standard of 50 µg/m3 is plotted in Figure 5.1-9. Note that since PM_{10} is generally measured only once every six days, expected violation days are usually about six times the number of measured violations. The trends of maximum annual average PM_{10} readings and the California standard are shown in Figure 5.1-10. Annual average PM_{10} concentrations are above the state standard of 20 µg/m^3.

TABLE 5.1-8
PM_{10} Levels at Stockton-Hazelton, Stockton, 1998-2007 (µg/m³)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Highest 24-hour Average										
State	115	155	97	147	91	90	61	84	85	75
Federal	106	150	91	140	87	88	60	79	82	71
Annual Arithmetic Mean (State Standard = 20 µg /m³)	30.1	37.7	33.7	36.6	36.1	28.4	29.4	29.8	33.4	27.7
Expected Number of Days Exceeding:										
State Standard (50 µg/m³, 24-hour)	49.8	67.2	52.1	64.1	58.4	17.3	18.0	46.5	62.9	23.5
Federal Standard (150 µg/m³, 24-hour)	0	0	0	0	0	0	0	0	0	0

Source: California Air Quality Data, Annual Summary, California Air Resources Board

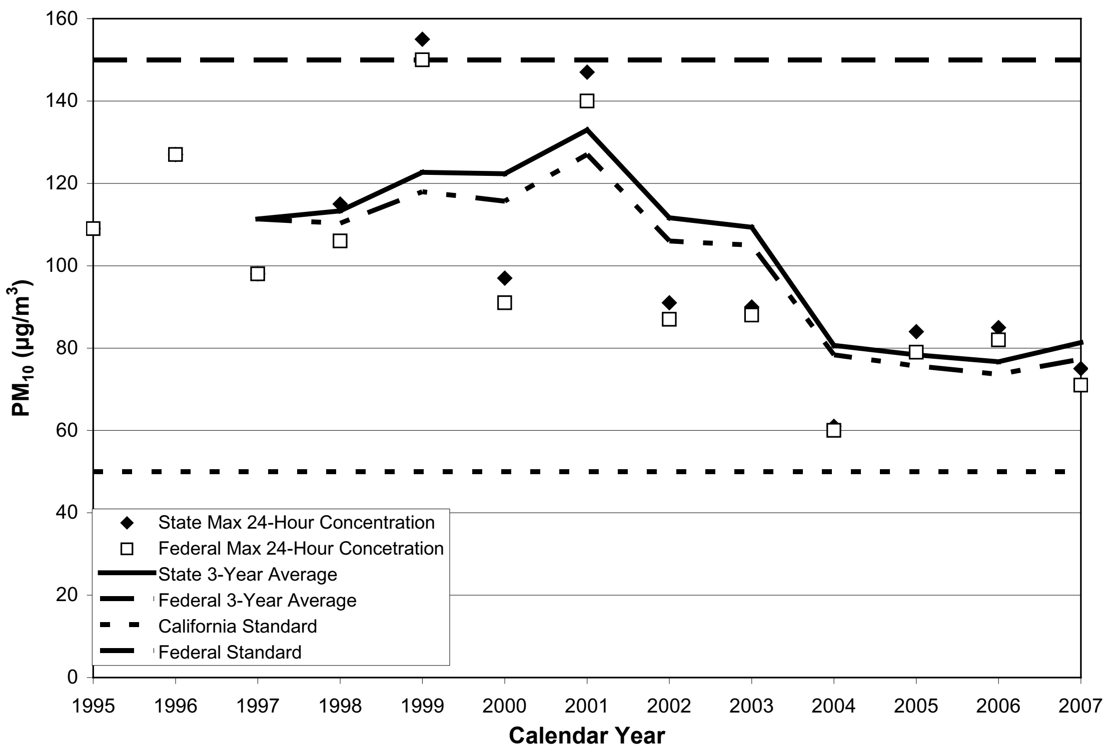


FIGURE 5.1-8
Maximum 24-hour Average PM_{10} Level: Stockton-Hazelton: 1995-2007

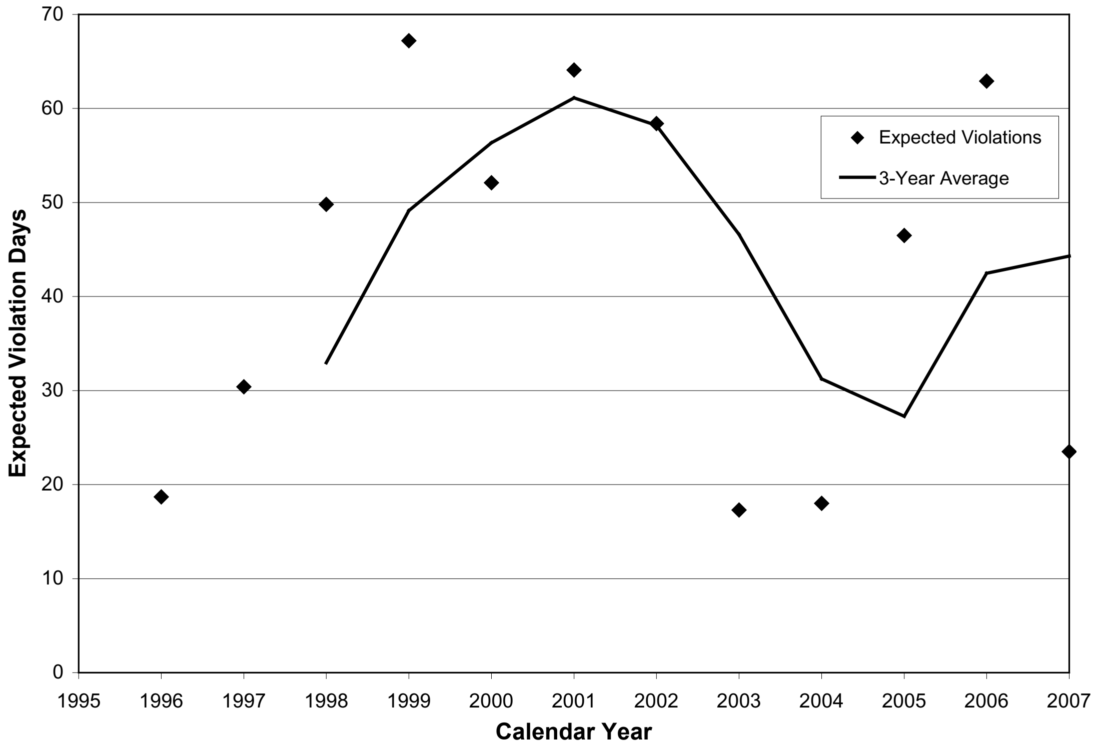


FIGURE 5.1-9
Expected Violations of the California 24-hour PM_{10} Standard: Stockton-Hazelton: 1995-2007

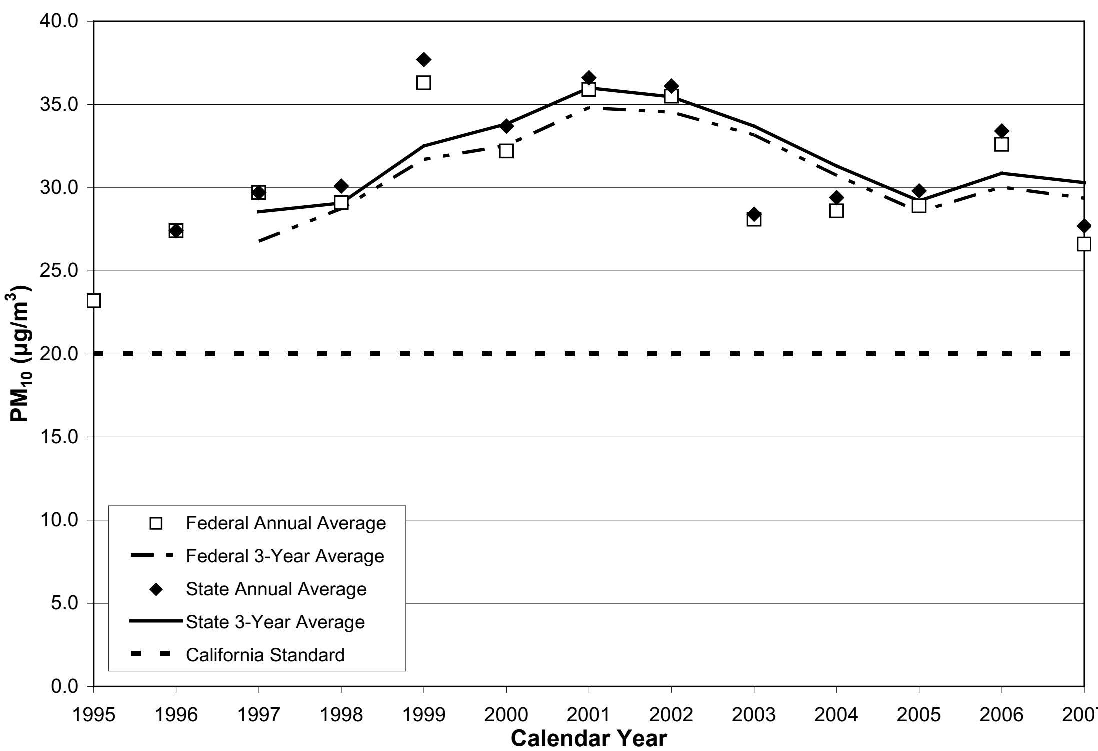


FIGURE 5.1-10
Annual Average PM_{10} Level: Stockton-Hazelton: 1995-2007

$PM_{2.5}$ is also measured at the Stockton-Hazelton monitoring station. Maximum 24-hour average readings have met EPA's federal standard (35 µg/m³) that is applied to the 3-year average 98th percentile reading, since 2002.

Table 5.1-9 shows the federal air quality standards for $PM_{2.5}$, maximum levels recorded at the Stockton-Hazelton monitoring station in Stockton during 1998-2007, and 3-year averages for the same period. Annual average $PM_{2.5}$ levels have exceeded the state standard during monitoring years, but have been below the federal standard since 2003. As for PM_{10}, $PM_{2.5}$ is measured only once every 6 days, so expected exceedances are 6 times the number of measured exceedances. The San Joaquin Valley Air Basin is considered a nonattainment area for the state $PM_{2.5}$ standard but the attainment status for the federal $PM_{2.5}$ standard has not yet been determined.

The trend of federal annual average $PM_{2.5}$ levels is plotted in Figure 5.1-11, and the trend of maximum 24-hour average levels is plotted in Figure 5.1-12.

TABLE 5.1-9
$PM_{2.5}$ Levels Stockton-Hazelton, Stockton, 1998-2007 (µg/m³)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Highest 24-hour Average	*	101	78	76	64	45	41	63	47	52
Number of Days Exceeding:										
Federal Standard (35 µg/m³, 24-hour)	*	15.3	3	5.9	0	0	0	0	0	0
98th Percentile	*	79	55	58	50	41	36	44	42	48
3-yr Average, 98th Percentile	*	*	*	64	54	50	42	40	41	45
Annual Arithmetic Mean	*	19.7	15.5	13.9	16.7	13.6	13.2	12.5	13.1	12.9
3-yr Annual Average	*	*	*	16.4	15.3	14.7	14.5	13.1	12.9	12.8
(Federal Std = 15 µg/m³)										

Source: California Air Quality Data, Annual Summary, California Air Resources Board

*There were insufficient (or no) data available to determine the value.

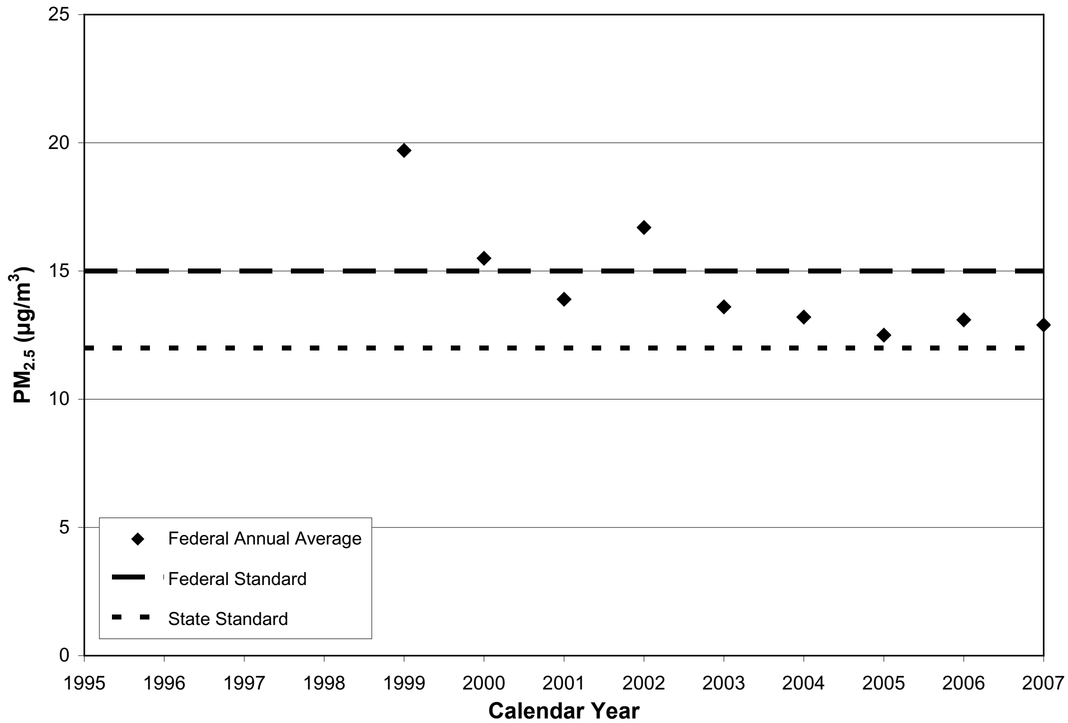


FIGURE 5.1-11
Federal Annual Average $PM_{2.5}$ Level: Stockton-Hazelton: 1999-2007

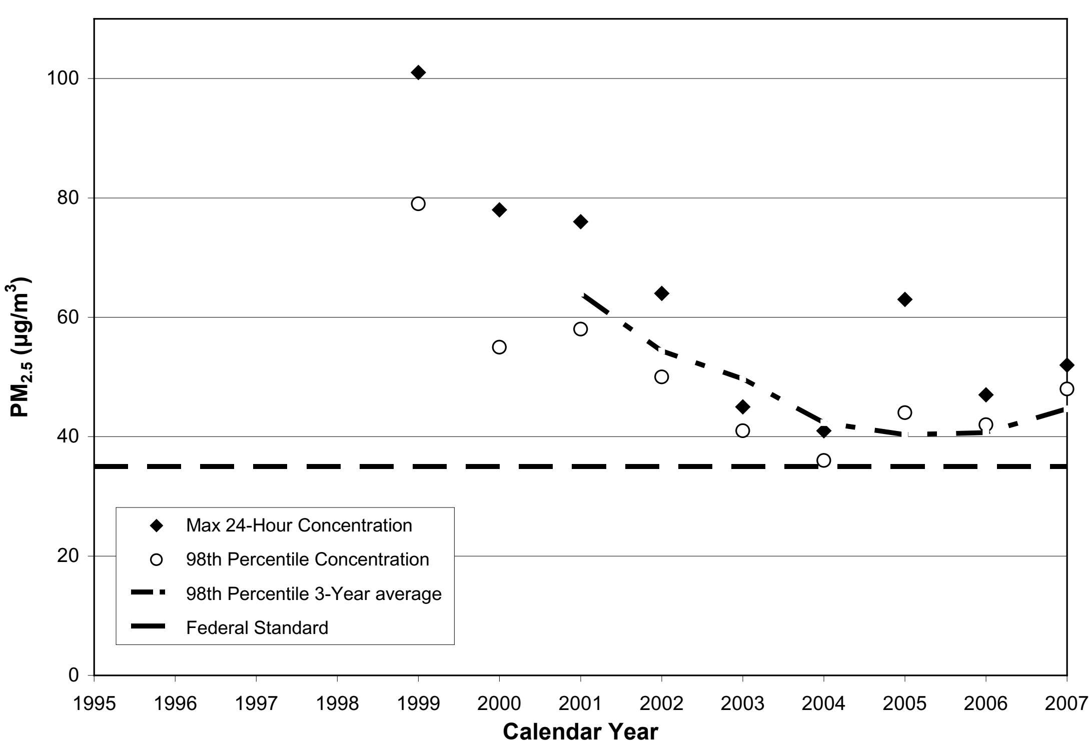


FIGURE 5.1-12
Maximum 24-Hour $PM_{2.5}$ Level: Stockton-Hazelton: 1999-2007

5.1.1.3.9 Airborne Lead

The majority of lead in the air results from the combustion of fuels that contain lead. Until 30 years ago, motor gasolines contained relatively large amounts of lead compounds used as octane-rating improvers, with the result that ambient lead levels were relatively high. Beginning with the 1975 model year, however, manufacturers began to equip new automobiles with exhaust catalysts, which are poisoned by the exhaust products of leaded gasoline. Thus, unleaded gasoline became the required fuel for an increasing fraction of new vehicles, and the phase out of leaded gasoline began. As a result, ambient lead levels decreased dramatically, and for several years California air basins, including the San Joaquin Valley Air Basin, have been in attainment of state and federal airborne lead standards for air quality planning purposes. Table 5.1-10 lists the state air quality standard for airborne lead and the levels recorded in the Stockton-Hazelton station between 1998 and 2003. Table 5.1-10 indicates that airborne lead levels have been well below the ambient air quality standard of 1.5 μg/m^3 for the period 1998 through 2003.

TABLE 5.1-10
Airborne Lead at Stockton-Hazelton, Stockton, 1998-2003(μg/m^3)

	1998	1999	2000	2001	2002	2003
Highest Daily Average	0.02	0.02	0.03	0.02	0.02	0.02
Number of Day Exceeding Federal Standard (1.5 μg/m^3)	0	0	0	0	0	0

Source: AIRData, EPA

5.1.2 Project Description

5.1.2.1 Current Facility

The equipment at the existing NCPA STIG plant consists of one 49 MW GE LM-5000 natural gas-fired, steam-injected (STIG) combustion gas turbine and one 240 HP Cummins diesel fire pump engine. There is also a small cooling tower at the facility, which is exempt from permitting under the SJVAPCD rules because its circulation rate is less than 10,000 gallons per minute (Rule 2020, Section 6.2). The only change to be made to the existing facility is the relocation of the exempt cooling tower.

5.1.2.2 Proposed Facility

The proposed combined-cycle unit will consist of a Siemens STG6-5000F ~~General Electric PG7241FA~~ combustion turbine, a heat recovery steam generator ~~with duct firing~~, and a 95 MW (nominal) condensing steam turbine, for a total nominal plant output of ~~255~~ 296 MW (nominal). The CTG will use ~~“Rapid Response”~~ “Flex Plant™ 30” rapid startup technology. The ~~Rapid Response~~ Flex Plant™ 30 package, which includes a modified HRSG design and an auxiliary boiler, is designed to allow earlier startup of the steam turbine by decoupling the gas turbine from the HRSG, thereby reducing startup emissions. The project will also include a cooling tower.

The combustion turbine~~, duct burners~~ and auxiliary boiler will be fueled exclusively with natural gas. The combustion turbine will be equipped with an inlet air evaporative cooling system to maintain turbine output across the full range of ambient temperatures. Based on operation at ~~an ambient temperature of 61.2°F, with evaporative cooling of the CTG inlet air~~

~~to 55.8°F and without duct firing~~ average annual conditions, the facility will have a heat rate of approximately ~~6,797~~6,824 Btu/kWh (HHV) (see Figure 2.1-4AR and 2.1-4BR). ~~The facility will have an incremental heat rate with duct firing of approximately 8,773 Btu/kWh (HHV).~~

Post-combustion air pollution controls for the gas turbine/HRSG will include SCR for NOx control and an oxidation catalyst for CO control. The turbine and HRSG may be operated up to 24 hours per day, 7 days per week. LEC will be frequently dispatched and will operate on the order of approximately a 76 to 82 percent annual capacity factor.

The auxiliary boiler is expected to operate only during turbine startups. Specifications for the new combustion turbine and HRSG are summarized in Table 5.1-11R; auxiliary boiler specifications are provided in Table 5.1-12R. A typical fuel analysis is summarized in Table 5.1-13.

TABLE 5.1-11R
New ~~GE 7FA~~ Siemens SCC6-5000F Combustion Turbine/HRSG Design Specifications

Gas Turbine Manufacturer:	Siemens ~~General Electric~~
Gas Turbine Model:	~~PG7241FA~~ STG6-5000F
Fuel:	Natural gas
Design Ambient Temperature*:	32.6°F ~~23.7°F~~
Nominal Heat Input Rate:	2142 MMBtu/hr ~~1885 MMBtu/hr @ HHV (gas turbine only)~~ ~~2107 MMBtu/hr @ HHV (gas turbine with duct firing)~~
Gas Turbine Nominal Power Generation Rate:	185 MW ~~180 MW~~
Plant Nominal Net Power Output:	296 MW ~~255 MW~~
Nominal Exhaust Temperature:	180 °F
Exhaust Flow Rate (nominal, base load):	1,116,524 acfm ~~991,425 acfm~~
Exhaust O_2 Concentration, dry volume:	13.7%
Exhaust CO_2 Concentration, dry volume:	4.1%
Exhaust Moisture Content, wet volume:	8.8%
Emission Controls:	Dry Low-NO_x burners and SCR (2.0 ppmv NO_x @ 15% O_2) Oxidation catalyst (3.0 ppmv CO @ 15% O_2)

*Low-temperature scenario.

TABLE 5.1-12R
New Auxiliary Boiler Design Specifications

Boiler Manufacturer:	Rentech Boiler Systems, Inc or acceptable equal
Boiler Model:	"D" type, model TBA
Fuel:	Natural gas
Nominal Heat Input Rate:	36.5 MMBtu/hr @ HHV ~~65 MMBtu/hr @ HHV~~
Nominal Steam Generation Rate:	30,000 lb/hr ~~45,000 lb/hr~~
Emission Controls:	Low-NO_x burner (7.0 ppmv NO_x @ 3% O_2)

TABLE 5.1-13
Nominal Fuel Properties—Natural Gas

Component Analysis		Chemical Analysis	
Component	**Average Concentration, Volume**	**Constituent**	**Percent by Weight**
CH_4	94.61%	C	71.42 %
C_2H_6	2.07%	H	23.47 %
C_3H_8	0.19%	N	3.75 %
C_4H_{10}	0.08%	O	1.36 %
C_5H_{12}	0.02%	S	1 gr/100 scf
N_2	2.27%	Higher Heating Value	1004 Btu/scf 22,524 Btu/lb
CO_2	0.65%		
S	<0.00%		

5.1.3 Emissions Evaluation

5.1.3.1 Current Facility Emissions and Permit Limitations

The existing facility potential to emit (PTE) is summarized in Table 5.1-14. Daily emissions from the existing combustion turbine are limited by permit, so annual PTE is calculated assuming maximum daily operation for 8760 days per year. Emissions from the emergency fire pump engine are calculated based on 50 hours per year limitation on testing and maintenance operations in the applicable CARB Air Toxic Control Measure.[3] Because the existing cooling tower is exempt from permitting, its emissions are assumed to be insignificant and are not included.

TABLE 5.1-14
Potential to Emit for Existing NCPA Lodi Equipment

	Emissions, tons per year*				
Unit	**NO_x**	**SO_2**	**CO**	**VOC**	**$PM_{10}/PM_{2.5}$**
LM5000 STIG	20.4	5.7	58.8	25.9	8.8
Emergency Diesel Fire Pump Engine	0.08	<0.01	0.04	0.01	0.01

*Detailed calculations provided in Appendix 5.1A, Tables 5.1A-1 and 5.1A-2.

5.1.3.2 Facility Operations

5.1.3.2.1 New ~~7FA~~ STG6-5000F Combustion Turbine ~~with Duct Firing~~

Project designers evaluated combustion turbine performance under three ~~five~~ temperature scenarios—~~extreme~~ maximum temperature ~~(107.7°F), typical summer temperature~~ (94°F), annual average temperature (61.2°F), ~~typical winter temperature (32.6°F),~~ and ~~extreme~~ minimum temperature (32.6°F ~~23.7°F~~). The ~~extreme~~ minimum temperature scenario ~~with duct firing~~ was used to characterize maximum emissions because it has the highest hourly

[3] Air Toxics Control Measure for Stationary Compression Ignition Engines, Title 17 CCR 93115 et seq.

heat input and emission rates. Maximum NOx, CO, and VOC emissions for each quarter are based on expected operations, including startups and shutdowns ~~duct firing~~, which are characteristic of the quarter. Maximum SO_2 and $PM_{10}/PM_{2.5}$[4] emissions are based on full-time operations~~, including duct firing~~. The quarterly operating profiles summarized in Table 5.1-15R below were used as the basis for the calculation of quarterly and annual emissions. These calculations are shown in more detail in Appendix 5.1A, Table 5.1A-6R.

TABLE 5.1-15R
Quarterly and Annual Operations for the CTG~~ and HRSG~~

	Hot Start Hours	Cold Start Hours ~~Duct Firing Hours~~	Base Load Hours	Total Heat Input, MMBtu (HHV)
Q1	100	42 ~~350~~	1,534 ~~1,184~~	4,626,983 ~~4,149,888~~
Q2	100	42 ~~350~~	1,558 ~~1,208~~	4,678,394 ~~4,195,135~~
Q3	40	36 ~~1100~~	1,900 ~~800~~	4,729,805 ~~4,406,844~~
Q4	72	36 ~~700~~	1,740 ~~1,040~~	4,729,805 ~~4,318,064~~
Annual	312	156 ~~2,500~~	7,200 ~~4,232~~	18,764,985 ~~17,069,130~~

5.1.3.2.2 New Auxiliary Boiler

The auxiliary steam boiler will provide steam during plant start-up and shut-down to allow startups and shutdowns to be accomplished more quickly. During pre-start activities and during the initial phases of start-up, steam for sealing, warming the steam turbine (optional), heating/re-heating condensate (condenser sparging steam), and combustion turbine fuel gas heating will be supplied from the auxiliary boiler. ~~Because the auxiliary boiler will be used mainly to support turbine startup activities, quarterly and annual boiler emissions are calculated based on projected turbine startup hours.~~ The quarterly operating profile assumed for the auxiliary boiler is shown in Table 5.1-16R. NCPA proposes that the daily and quarterly operating limitations on auxiliary boiler operation be expressed in terms of heat input rather than hours of operation. The proposed daily and quarterly fuel use limitations are based on 24 hours per day and 1 000 hours per quarter of boiler operation.

[4] All combustion PM is assumed to be less than 2.5 microns in diameter; therefore all PM_{10} is assumed to be $PM_{2.5}$.

TABLE 5.1-16R
Daily, Quarterly and Annual Operations for the Auxiliary Boiler

	~~Total Hours~~	Proposed Fuel Use Limitation for Period (MMBtu HHV)
Daily	~~12*~~	877* ~~780~~
Quarterly ~~Q1~~	~~142~~	36,550 ~~9,230~~
~~Q2~~	~~142~~	36,550 ~~9,230~~
~~Q3~~	~~76~~	36,550 ~~4,940~~
~~Q4~~	~~108~~	36,550 ~~7,020~~
Annual	~~468~~	146,200 ~~30,420~~

*Although the auxiliary boiler is expected to operate only during CTG startup, maximum daily emissions from the unit are evaluated assuming up to 24~~12~~ hours per day and 1000 hours per quarter (4000 hours per year) of operation to provide maximum operational flexibility.

5.1.3.2.3 New Cooling Tower

The cooling tower circulates cooling water and is used to condense steam discharging from the steam turbine. For this application, the cooling tower is assumed to operate 24 hours per day, 8,760 hours per year.

5.1.3.3 Normal Operations

The operating profiles described in Section 5.1.3.2 were used to develop daily, quarterly, and annual heat input limits for the fuel-burning equipment. These heat input limits, summarized in Table 5.1-17R, were used as the basis for calculating project and facility emissions.

TABLE 5.1-17R
Hourly, Daily and Annual Heat Input for the New Combustion Units

	Heat Input, MMBtu (HHV)	
Interval	CTG ~~with duct firing~~	Aux. Boiler
Hourly	2,142.1 ~~2,107.2~~	36.5 ~~65~~
Daily	51,411 ~~47,910~~	877 ~~780~~
Annual	18,764,985 ~~17,096,930~~	146,200 ~~30,420~~

5.1.3.4 Criteria Pollutant Emissions

Criteria pollutants emitted from the fuel-burning equipment include NO_x, SO_2, CO, VOC, and fine particulate matter (PM_{10}).[5] The cooling tower will emit small quantities of PM_{10}. This section of the application presents calculated emissions from the new equipment.

The new equipment also will emit trace levels of toxic air contaminants (TACs), including ammonia. TAC emissions from the proposed new units are discussed in Section 5.1.3.5. Tables containing the detailed TAC emission calculations are included in Appendix 5.1A.

5.1.3.4.1 Criteria Pollutant Emissions: Combustion Turbine and HRSG

Proposed maximum emissions from the project were estimated on an hourly, daily, quarterly and annual basis based on expected daily operation and proposed quarterly and annual operating limitations.

Emissions During Normal Operations

Turbine and HRSG performance data are provided in Appendix 5.1A, Table 5.1A-3R. Emissions of NO_x, CO, and VOC were calculated from emission limits (in ppmv @ 15 percent O_2) and the exhaust flow rates. The NO_x emission limit reflects the application of SCR. The VOC emission limit reflects the use of good combustion practices. The CO emission limit reflects the expected performance of the oxidation catalyst. Maximum emissions were based on the exhaust rates associated with the heat input rates shown in Table 5.1-17R.

SO_2 emissions were calculated from the heat input (in MMBtu) and an SO_2 emission factor (in lb/MMBtu). SO_2 emissions were calculated based on the maximum allowable fuel sulfur content of 1 grain per 100 standard cubic feet (scf) and the heat input rates in Table 5.1-17R.

Maximum hourly PM_{10} emissions reflect expected turbine/HRSG performance, based on emissions limits from similar installations. $PM_{2.5}$ emissions were determined based on the assumption that all particulate matter emissions are less than 2.5 microns in size.

Maximum emission rates are summarized in Table 5.1-18R. The BACT analysis upon which the emission factors are based is presented in Appendix 5.1C and summarized in Section 5.1.7.

TABLE 5.1-18R
Maximum Emission Rates—Combustion Turbine/HRSG

Pollutant	ppmv @ 15% O_2	lb/MMBtu	lb/hr
Combustion Turbine ~~without Duct Firing~~			
NO_x	2.0	0.0072	15.54 ~~13.64~~
SO_2[b]	0.57	0.0028	6.10 ~~5.37~~
CO	3.0	0.0066	14.19 ~~12.46~~
VOC	1.4	0.0018	3.79 ~~3.33~~

5 All of the particulate matter emitted from the fuel burning equipment and the cooling tower is assumed to be less than 2.5 microns in diameter. All references to PM_{10} include $PM_{2.5}$ as well.

TABLE 5.1-18R
Maximum Emission Rates—Combustion Turbine/HRSG

Pollutant	ppmv @ 15% O_2	lb/MMBtu	lb/hr
$PM_{10}/PM_{2.5}$[c]	--	--	9.0
~~**Combustion Turbine with Duct Firing**~~			
~~NO_x~~	~~2.0~~	~~0.0072~~	~~15.25~~
~~SO_2[d]~~	~~0.57~~	~~0.0028~~	~~6.00~~
~~CO~~	~~3.0~~	~~0.0066~~	~~13.93~~
~~VOC~~	~~2.0~~	~~0.0028~~	~~5.32~~
~~$PM_{10}/PM_{2.5}$[e]~~	~~--~~	~~--~~	~~11.0~~

[a]NO_x, CO, VOC, and PM_{10} emission rates exclude startups and shutdowns (see Table 5.1-19).

[b]Based on maximum natural gas sulfur content of 1 gr/100 scf. See text.

[c]Includes front and back half.

Emissions During Startup and Shutdown

Emissions of NO_x, CO, and VOC during turbine startup and shutdown will be higher than under normal operating conditions because the unit must operate at reduced loads while downstream components, including the HRSG, gas turbine and emissions control systems reach operating temperatures. As discussed in Section 2, NCPA is installing Flex Plant fast-starting ~~Rapid Response~~ technology at LEC to minimize turbine startup times; this technology is expected to significantly reduce startup times and, consequently, startup emissions. However, peak hourly emissions during startup will not necessarily be reduced. Further, since no Flex Plant ~~Rapid Response~~ configuration plants have yet been built or operated, no in-use operating data are yet available to allow observation and evaluation of the actual times required for a unit to come into compliance during a startup. Therefore, NCPA is conservatively assuming that the times required for startups of the LEC will be the same as those for conventional Frame 7-based combined cycle turbine plants. However, NCPA is also proposing permit language that will require reassessment of startup times after the first full year of operating experience with the new Flex Plant design. This proposal is provided with the discussion of compliance with District Rule 4703, in Section 5.1.7.3 of this application.

The NO_x, CO, and VOC startup and shutdown emission rates used in calculating maximum hourly, daily, quarterly, and annual emissions from the LEC are shown in Table 5.1-19. SO_2 and PM_{10} emissions are not included in this table because emissions of these pollutants will not be higher during startup than during baseload facility operation.

Under cold start and warm start conditions, where the CTG has been shut down for more than 72 and 48~~12~~ hours, respectively, it is assumed that the CTG will require 6 hours to come into compliance with permitted emission rates. Under hot start conditions, where the CTG has been shut down for less than 8 ~~12~~ hours, it is assumed that the CTG can come into compliance in 2 hours.

TABLE 5.1-19
Maximum CTG Startup and Shutdown Emission Rates

	NO_x	CO	VOC
Startup, pounds per maximum hour	160	900	16
Startup, pounds per average hour	100	900	16
Shutdown, pounds per hour	100	900	16

5.1.3.4.2 Criteria Pollutants: Auxiliary Boiler

The emission rates for the auxiliary boiler shown in Table 5.1-20R are based on manufacturers' guaranteed emission rates and best available control technology requirements. The BACT determination is provided in Appendix 5.1C. Emission rates and calculated hourly emissions for this unit are shown in Appendix 5.1A, Table 5.1A-4R. The emission rates in ppm and lb/MMBtu have not changed from those presented in the AFC. However, as discussed above, as part of the revised project design, the size of the boiler has been reduced from 65 MMbtu/hr to 36.5 MMBtu/hr of heat input so the hourly emissions from the unit are lower than those for the original project design.

TABLE 5.1-20R
Maximum Emission Rates—Auxiliary Boiler

Pollutant	ppmv @ 3% O_2	lb/MMBtu	lb/hr
NO_x	7.0	0.0084	0.31~~0.6~~
SO_2[a]	1.69	0.0028	0.10~~0.2~~
CO	50	0.0365	1.34~~2.4~~
VOC	10	0.0042	0.15~~0.3~~
$PM_{10}/PM_{2.5}$[b]	—	—	0.28~~0.5~~

[a]Based on maximum natural gas sulfur content of 1 gr/100 scf (see text).

[b]Includes front and back half.

5.1.3.4.3 Criteria Pollutants: Cooling Tower

The emission rates for the cooling tower are based on manufacturer's drift rate and the maximum cooling water TDS level. Emissions calculations for this unit are shown in Appendix 5.1A, Table 5.1A-5R. The cooling water flow rate and TDS have increased as part of the new project design; the revised cooling tower emissions calculations reflect these changes.

5.1.3.4.4 Criteria Pollutant Emissions Summary for the New Equipment

Maximum facility emissions are shown in Table 5.1-21R. The emission calculations are based on the CTG/HRSG and auxiliary boiler emission rates shown in Tables 5.1-18R and 5.1-19R; the fuel use limitations in Table 5.1-17R; and the operating assumptions shown in Tables 5.1-15R and 5.1-16R. Because the new project design eliminates duct firing in the HRSG, maximum ~~Maximum~~ daily operations are based on full-load operation of the turbine for 24 hours ~~with 12 hours of duct firing for PM_{10} and SO_x, and~~ with 6 hours of cold start and 18 hours of base load turbine operation ~~and 12 hours of duct firing for NO_x, CO, and VOC~~.

These assumptions are used as the basis for the calculations and are not intended to be proposed as limits.

Detailed calculations, including quarterly emissions calculations, are shown in Appendix 5.1A, Table 5.1A-6R.

TABLE 5.1-21R
Criteria Pollutant Emissions from New Equipment

Emissions/Equipment	NO_x	SO_2	CO	VOC	PM_{10}
Maximum Hourly Emissions[a]					
CTG/HRSG	160	6.1~~6.0~~	900	16	9.0 ~~11.0~~
Auxiliary Boiler	0.31~~0.55~~	0.10~~0.19~~	1.34~~2.37~~	0.15~~0.27~~	0.28 ~~0.47~~
Cooling Tower	—	—	—	—	0.9 ~~0.45~~
Total, pounds per hour	**160.3** ~~**160.5**~~	**6.2**	**901.3** ~~**902.4**~~	**16.2** ~~**16.3**~~	**10.2** ~~**11.9**~~
Maximum Daily Emissions[b]					
CTG/HRSG	879.7 ~~864.9~~	146.4 ~~136.4~~	5,655.4 ~~5,641.9~~	164.3 ~~179.8~~	216.0 ~~240.0~~
Auxiliary Boiler	7.4 ~~6.5~~	2.5 ~~2.2~~	32.1 ~~28.5~~	3.7 ~~3.3~~	6.7 ~~11.3~~
Cooling Tower	—	—	—	—	22.3 ~~5.6~~
Total, pounds per day	**887.0** ~~871.4~~	**148.9** ~~138.6~~	**5,687.5** ~~5,670.4~~	**167.9** ~~183.1~~	**245.1** ~~256.4~~
Maximum Annual Emissions					
CTG/HRSG	75.7~~71.3~~	26.7~~24.3~~	258.4 ~~254.4~~	16.5 ~~17.4~~	39.4~~41.9~~
Auxiliary Boiler	0.6~~0.13~~	0.2~~0.04~~	2.7~~0.6~~	0.3~~0.1~~	0.6~~0.1~~
Cooling Tower	—	—	—	—	4.1~~2.0~~
Total, tons per year	**76.3** ~~71.5~~	**26.9** ~~24.3~~	**261.0** ~~254.9~~	**16.8** ~~17.5~~	**44.1** ~~44.0~~

[a]Maximum hourly emissions include CTG in startup (for NO_x, CO and VOC), with auxiliary boiler and cooling tower in operation. ~~Maximum hourly SO_2 and PM_{10} emissions from the CTG assume duct fired operation.~~

[b]Maximum daily emissions based on full-load turbine operation for 24 hours ~~with 12 hours of duct firing~~ for PM_{10} and SO_x; and 6 hours of cold start and 18 hours of base load turbine operation ~~and 12 hours of duct firing~~ for NO_x, CO, and VOC.

5.1.3.5 Greenhouse Gas Emissions

Greenhouse gas (GHG) emissions from the project have been calculated using calculation methods and emission factors from the California Air Resources Board's December 5, 2007, regulatory update.[6] Calculations are based on the maximum proposed annual fuel use and

6 California Air Resources Board, "Regulation for the Mandatory Reporting of Greenhouse Gas Emissions," December 5, 2007 (Staff's Suggested Modifications to the Originally Proposed Regulation Order Released October 19, 2007). http://www.arb.ca.gov/cc/ccei/reporting/GHGReportRegUpdate12_05_07.pdf.

corresponding generation. The calculations are shown in detail in Table 5.1A-7R, Appendix 5.1A and the results are summarized in Table 5.1-22R.

TABLE 5.1-22R
Greenhouse Gas Emissions from New Equipment

Unit	CO_2, metric tonnes/yr	CO_2. metric tonnes/MWh	CO_2eq, metric tonnes/yr[a]
CTG/HRSG	925,356 ~~902,487~~	0.354 ~~0.376~~	—
Auxiliary Boiler	7,730 ~~1,608~~	Not applicable	–
Total	933,086 ~~904,095~~	0.357~~0.376~~	933,989 ~~904,971~~

*Includes CH_4, N_2O and SF_6.

5.1.3.6 Hazardous Air Pollutants

Noncriteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[7] In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1). The SJVAPCD regulates toxic air contaminant emissions under the SJVAPCD's Integrated Air Toxic Program. This program integrates the state and federal requirements. Any pollutant that may be emitted from the LEC and is on the federal New Source Review list, the federal Clean Air Act list, and/or the SJVAPCD toxic air contaminant list has been evaluated as part of the AFC.

5.1.3.6.1 Toxic Air Contaminant Emissions: New Gas Turbine/HRSG and Auxiliary Boiler

Maximum hourly and annual TAC emissions were estimated for the gas turbine/HRSG and the auxiliary boiler based on the heat input rates (in MMBtu/hr and MMBtu/yr), emission factors (in lb/MMBtu), and the nominal fuel higher heating value of 1004 Btu/scf. Hourly and annual emissions were based on the heat input rates shown in Table 5.1-17R. The ammonia emission factor was derived from an ammonia slip limit of 10 ppmv @ 15 percent O_2. At the request of the SJVAPCD [8], Ventura County emission factors were used to quantify other TAC emissions. The Ventura County AB2588 combustion emission factors do not include factors for hexane or propylene oxide or for speciated polyaromatic hydrocarbons (PAHs), so emission factors for these TACs were taken from the California Air Resources Board's CATEF database for natural gas-fired gas turbines. TAC emissions are summarized in Table 5.1-22R. Detailed emissions calculations, including emission factors, are provided in Appendix 5.1A, Tables 5.1A-8R and 5.1A-9R.

5.1.3.6.2 Toxic Air Contaminant Emissions: Cooling Tower

Maximum hourly and annual TAC emissions from the cooling tower are extremely low. As shown in Table 5.15-23, concentrations of most metals and salts in the water supply were below detection limits. Total TAC emissions from the cooling tower are shown in Appendix 5.1A, Table 5.1A-10R.

7 These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission.

8 June 5, 2008, email message from Cheryl Lawler to Nancy Matthews, "District's Comments for Lodi Energy Center Modeling Protocol."

5.1.3.6.3 Toxic Air Contaminant Emissions: Existing Turbine

Maximum annual TAC emissions from the existing turbine have been calculated using the same emission factors as those used for the new turbine/HRSG and are summarized below in Table 5.1-23R. Detailed calculations are shown in Appendix 5.1A, Table 5.1A-11R.

TABLE 5.1-23R
Maximum Proposed TAC Emissions for the CTG/HRSG

Compound	Maximum Emissions, CTG/HRSG		Maximum Emissions, Aux Boiler	
	lb/hr	tpy	lb/hr	tpy
Ammonia[a]	28.8~~28.2~~	126.0~~114.3~~	0	0
Propylene	1.6	7.2~~6.6~~	0.03	<0.01
Hazardous Air Pollutants				
Acetaldehyde	0.09~~0.08~~	0.4~~0.3~~	<0.01	<0.01
Acrolein	0.01	0.06~~0.05~~	<0.01	<0.01
Benzene	0.03	0.1	<0.01	<0.01
1,3-Butadiene	0.001	0.004	<0.01	<0.01
Ethylbenzene	0.07	0.3	<0.01	<0.01
Formaldehyde	1.5	6.7~~6.1~~	<0.01	<0.01
Hexane	0.6~~0.5~~	2.4~~2.2~~	<0.01	<0.01
Naphthalene	0.003	0.01	<0.01	<0.01
PAHs[b]	0.002~~<0.001~~	0.008~~0.003~~	<0.01	<0.01
Toluene	0.3	1.2~~1.1~~	<0.01	<0.01
Xylene	0.1	0.6	<0.01	<0.01

[a]Based on 10 ppmc ammonia slip from CTG/HRSG SCR system. No ammonia use or emissions for auxiliary boiler.

[b]Excluding naphthalene. See Appendix 5.1A, Table 5.1A-8R.

5.1.3.7 Total HAP Emissions After Modification

Total HAP emissions from the existing and new equipment are shown in Table 5.1-24R below. Note that ammonia and propylene are not HAPs and are not included in the calculation of total HAPs from the facility after modification.

TABLE 5.1-24R
Total HAP Emissions from the Facility After Modification

Emissions Unit	Maximum Individual HAP Emissions, tons per year	Total HAP Emissions, tons per year
New LEC CTG/HRSG	6.7~~6.1~~	12.2~~11.1~~
New LEC Auxiliary Boiler	<0.01	<0.01
Existing STIG Turbine	1.4	2.6
Total	8.1~~7.5~~	14.8~~13.8~~

5.1.3.8 Construction

Emissions during the construction phase of the project have been estimated, including an assessment of emissions from vehicle and equipment exhaust and the fugitive dust generated from material handling. A detailed analysis of the emissions and ambient impacts is included in Appendix 5.1E. Construction emissions mitigation and/or control techniques proposed for use at the LEC site include but are not limited to the following:

- Operational measures, such as limiting time spent with the engine idling by shutting down equipment when not in use;
- Regular preventive maintenance to prevent emission increases due to engine problems;
- Use of low sulfur and low aromatic fuel meeting California standards for motor vehicle diesel fuel; and
- Use of low-emitting gas and diesel engines meeting state and federal emissions standards for construction equipment, including, but not limited to, catalytic converter systems and Diesel particulate filter systems.

The following mitigation measures are proposed to control fugitive dust emissions during construction of the project:

- Use either water application or chemical dust suppressant application to control dust emissions from onsite unpaved road travel and unpaved parking areas;
- Use vacuum sweeping and/or water flushing of paved road surfaces to remove buildup of loose material to control dust emissions from travel on the paved access road (including adjacent public streets impacted by construction activities) and paved parking areas;
- Cover all trucks hauling soil, sand, and other loose materials or require all trucks to maintain at least two feet of freeboard;
- Limit traffic speeds on all unpaved site areas to 15 mph;
- Install sandbags or other erosion control measures to prevent silt runoff to roadways;
- Replant vegetation in disturbed areas as quickly as possible;
- Use wheel washers or wash off tires of all trucks exiting construction site; and
- Mitigate fugitive dust emissions from wind erosion of areas disturbed from construction activities (including storage piles) by application of either water or chemical dust suppressant.

The LEC construction site impacts are not unusual in comparison to most construction sites. Construction sites that use good dust suppression techniques and low-emitting vehicles typically do not cause violations of air quality standards.

5.1.4 Best Available Control Technology Evaluation

5.1.4.1 Current Facility Control Technologies

The existing NCPA gas turbine is an aeroderivative LM5000 STIG unit that uses steam injection for NO_x control and power augmentation. The gas turbine also uses selective catalytic reduction (SCR) and an oxidation catalyst to achieve additional NO_x control and to control CO emissions, respectively. NO_x emissions are limited to 3.0 ppmvd and CO emissions are limited to 200 ppmvd, both corrected to 15% O_2 on a 3-hour rolling average basis.

5.1.4.2 Proposed Facility Best Available Control Technology

BACT is defined in 40 CFR 52.21(j) as:

"an emissions limitation…based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant…"

The SJVAPCD defines BACT as the most stringent emission limitation or control technique that:

"Has been achieved in practice for such emissions unit and class of source; or

Is contained in any SIP approved by the EPA for such emissions unit category and class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed emissions unit demonstrates to the satisfaction of the Air Pollution Control Officer (APCO) that such limitation or control technique is not presently achievable; or

Is any other emission limitation or control technique, including process and equipment changes of basic and control equipment, found by the APCO to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as determined by the APCO."

A top-down BACT analysis is required for each pollutant that is subject to PSD review or that exceeds the SJVAPCD BACT thresholds. BACT applicability is discussed in Section 5.1.7.3. The required top-down BACT analysis is provided in Appendix 5.1C, and concludes that BACT for the proposed project is as shown in Table 5.1-25R. Because duct firing has been eliminated from the project description, the proposed BACT emission limit for VOC is now 1.4 ppmc during all modes of operation except startup and shutdown.

TABLE.1-25R
BACT Determinations for LEC

Pollutant	Gas Turbine/HRSG	Auxiliary Boiler
NO_x	Dry low-NO_x combustor and selective catalytic reduction: 2.0 ppmc,[a] 1-hour average	Ultra-low NO_x burner: 7 ppmc[b]
CO	Oxidation catalyst: 3.0 ppmc, 3-hour average	Good combustion practices
VOC	1.4 ppmc~~, no duct firing~~ ~~2.0 ppm, with duct firing~~ 3-hour average	Good combustion practices
SO_2 and PM_{10}	Natural gas fuel and good combustion practices; inlet air filter; lube oil vent coalescer	Natural gas fuel and good combustion practices

[a]ppmc: parts per million by volume, dry. Gas Turbine/HRSG concentrations are corrected to 15% O_2.

[b]Boiler concentrations are corrected to 3% O_2.

5.1.5 Air Quality Impact Analysis

SJVAPCD Rule 2201 requires the Applicant to provide ambient air quality modeling analyses and other impact assessments. An ambient air quality impact assessment is also required by EPA for PSD review and by the CEC for CEQA review. These analyses are presented in this section. The air quality impact analyses have been prepared in accordance with modeling protocols submitted to and reviewed by the SJVAPCD and CEC staffs. The protocols and the comments provided are included in Appendix 5.1B.

5.1.5.1 Dispersion Modeling

An assessment of impacts from the LEC on ambient air quality has been conducted using EPA-approved air quality dispersion models. These models are based on various mathematical descriptions of atmospheric diffusion and dispersion processes in which a pollutant source impact can be calculated over a given area.

Figure 5.1B-1R in Appendix 5.1B shows the building layout used in the modeling analysis. The facility fenceline has also been changed slightly to avoid biologically sensitive habitat. Since the new equipment will operate alongside the existing plant, the modeling analysis included the existing STIG plant structures to account for any potential influences from those structures. The impact analysis was used to determine the worst-case ground-level impacts of the new equipment. The results were compared with established state and federal ambient air quality standards and PSD significance levels. If the standards are not exceeded then it is assumed that, in the operation of the facility, no exceedances are expected under any conditions. In accordance with the air quality impact analysis guidelines developed by EPA (40 CFR Part 51, Appendix W: Guideline on Air Quality Models) and CARB (Reference Document for California Statewide Modeling Guideline, April 1989), the ground-level impact analysis includes the following assessments:

- Impacts in simple, intermediate, and complex terrain;
- Aerodynamic effects (downwash) due to nearby building(s) and structures; and
- Impacts from inversion breakup (fumigation).

Simple, intermediate, and complex terrain impacts were assessed for all meteorological conditions that would limit the amount of final plume rise. Plume impaction on elevated terrain, such as on the slope of a nearby hill, can cause high ground-level concentrations, especially under stable atmospheric conditions. Another dispersion condition that can cause high ground-level pollutant concentrations is caused by building downwash. Building downwash can occur when wind speeds are high and a building or structure is in close proximity to the emission stack. This can result in building wake effects where the plume is drawn down toward the ground by the lower pressure region that exists in the lee side (downwind) of the building or structure.

Fumigation conditions occur when the plume is emitted into a low-lying layer of stable air (inversion) that then becomes unstable, resulting in a rapid mixing of pollutants towards the ground. The low mixing height that results from this condition allows little diffusion of the stack plume before it is carried downwind to the ground. Although fumigation conditions rarely last as long as an hour, relatively high ground-level concentrations may be reached during that period. Fumigation tends to occur under clear skies and light winds, and is more prevalent in the summer.

The basic model equation used in this analysis assumes that the concentrations of emissions within a plume can be characterized by a Gaussian distribution about the centerline of the plume. Concentrations at any location downwind of a point source such as a stack can be determined from the following equation:

$$C(x,y,z,H) = \left(\frac{Q}{2\pi\sigma_y\sigma_z u}\right) * \left(e^{-1/2(y/\sigma_y)^2}\right) * \left[\left\{e^{-1/2(z-H/\sigma_z)^2}\right\} + \left\{e^{-1/2(z+H/\sigma_z)^2}\right\}\right]$$

where

C = the concentration in the air of the substance or pollutant in question

Q = the pollutant emission rate

σ_y,σ_z = the horizontal and vertical dispersion coefficients, respectively, at downwind distance x

u = the wind speed at the height of the plume center

x,y,z = the variables that define the 3-dimensional Cartesian coordinate system used; the downwind, crosswind, and vertical distances from the base of the stack

H = the height of the plume above the stack base (the sum of the height of the stack and the vertical distance that the plume rises due to the momentum and/or buoyancy of the plume)

Gaussian dispersion models are approved by EPA for regulatory use and are based on conservative assumptions (i.e., the models tend to overpredict actual impacts by assuming steady-state conditions, no pollutant loss through conservation of mass, no chemical reactions, etc.). The EPA models were used to determine if ambient air quality standards would be exceeded, and whether a more accurate and sophisticated modeling procedure would be warranted to make the impact determination. The following sections describe:

- Screening modeling procedures

- Refined air quality impact analysis
- Existing ambient pollutant concentrations and preconstruction monitoring
- Results of the ambient air quality modeling analyses
- PSD increment consumption

5.1.5.2 Model Selection

The screening and refined air quality impact analyses were performed using the American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee (AERMIC) model, also known as AERMOD (current version 07026~~04300~~). The AERMOD model is a steady-state, multiple-source, Gaussian dispersion model designed for use with stack emission sources situated in terrain where ground elevations can exceed the stack heights of the emission sources (i.e. complex terrain).[9] The model is capable of estimating concentrations for a wide range of averaging times (from 1 hour to 1 year).

Inputs required by the AERMOD model include the following:

- Model options
- Meteorological data
- Source data
- Receptor data

Model options refer to user selections that account for conditions specific to the area being modeled or to the emissions source that needs to be examined. Examples of model options include use of site-specific vertical profiles of wind speed and temperature; consideration of stack and building wake effects; and time-dependent exponential decay of pollutants. The model supplies recommended default options for the user for some of these parameters.

AERMOD uses hourly meteorological data to characterize plume dispersion. The representativeness of the data is dependent on the proximity of the meteorological monitoring site to the area under consideration, the complexity of the terrain, the exposure of the meteorological monitoring site, and the period of time during which the data are collected. The meteorological data used in this analysis were collected at Stockton~~the Woodley Island NWS~~.

5.1.5.3 Good Engineering Practice Stack Height Analysis

For the purposes of modeling, a stack height beyond what is required by Good Engineering Practices (GEP) is not allowed (40 CFR Part 60 §51.164). However, this requirement does not place a limit on the actual constructed height of a stack. GEP as used in modeling analyses is the height necessary to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, or wakes that may be created by the source itself, nearby structures, or nearby terrain obstacles. In addition, the GEP stack height modeling restriction assures that any required regulatory control measure is not compromised by the effect of that

[9] AERMOD was adopted in November 2005 as a guideline model by EPA as a replacement for ISCST3. AERMOD incorporates an improved downwash algorithm as compared to ISCST3 (Federal Register, November 9, 2005; Volume 70, Number 216, Pages 68218-68261).

portion of the stack that exceeds the GEP height. The EPA guidance ("Guideline for Determination of Good Engineering Practice Stack Height," Revised 6/85) for determining GEP stack height indicates that GEP is the lesser of 65 meters or H_g, where H_g is calculated as follows:

$H_g = H + 1.5L$

Where:

H_g = Good Engineering Practice stack height, measured from the ground-level elevation at the base of the stack

H = height of nearby structure(s) measured from the ground-level elevation at the base of the stack

L = lesser dimension, height or maximum projected width, of nearby structure(s)

In using this equation, the guidance document indicates that both the height and width of the structure are determined from the frontal area of the structure, projected onto a plane perpendicular to the direction of the wind. For the LEC, the nearest influencing structure is the HRSG, which is 105 feet above ground level. Therefore, GEP stack height is 2.5 times that height, or 262.5 feet. The proposed stack height of 150 feet will not exceed GEP stack height, so the full physical stack height may be used in the modeling analysis.

For regulatory applications, a building is considered sufficiently close to a stack to cause wake effects when the downwind distance between the stack and the nearest part of the building is less than or equal to five times the lesser of the height or the projected width of the building. Building dimensions for the buildings analyzed as downwash structures were obtained from plot plans. The building dimensions were analyzed using the Lakes Environmental Building Profile Input Program (BPIP) to calculate 36 wind-direction-specific building heights and projected building widths for use in building wake calculations. The building dimensions used in the GEP analysis are shown in Appendix 5.1B, Table 5.1B-1R. As the existing power plant structures will remain in place, those structures are reflected in the downwash analysis.

5.1.5.4 Receptor Grid Selection and Coverage

Receptor and source base elevations were determined from USGS Digital Elevation Model (DEM) data using the 7½-minute format (10- to 30-meter spacing between grid nodes). All coordinates were referenced to UTM North American Datum 1927 (NAD27), Zone 10. The AERMOD receptor elevations were interpolated among the DEM nodes according to standard AERMAP procedure. For determining concentrations in elevated terrain, the AERMAP terrain preprocessor receptor-output (ROU) file option was chosen. Hills were not imported into AERMOD for CTDM-like processing.

Cartesian coordinate receptor grids were used to provide adequate spatial coverage surrounding the project area for assessing ground-level pollution concentrations, to identify the extent of significant impacts, and to identify maximum impact locations. A 250-meter resolution coarse receptor grid was developed, which extend outwards at least 10 km from the location of the new turbine stack.

In addition, more refined nested grids were developed to efficiently identify the maximum impact areas. These nested grids had the following resolutions:

- 25-meter resolution along the facility fence line in a single tier of receptors composed of four segments extending out to 100 meters from the fence line;
- 100-meter resolution from 100 meters to 1,000 meters from the fence line; and
- 250-meter resolution from 1 km out to at least 10 km from the site.

When maximum impacts occurred in the 100- or 250-meter spaced areas, additional refined receptor grids with 25-meter resolution were placed around each maximum coarse grid impact and extended out to a distance of two coarse grid spacings from the coarse grid maxima in all directions from that point of impact. Concentrations within the facility fence line, representing property controlled by NCPA, were not calculated. As discussed above, some portions of the fenceline have been moved to avoid biologically sensitive areas. This resulted in small changes in receptor locations, especially near the fenceline.

5.1.5.5 Meteorological Data Selection

SJVAPCD has prepared meteorological data sets applicable to most locations in the district and has processed them, using AERMET (Version 06341), into the format required by AERMOD. Hourly surface meteorological data (e.g., hourly wind speed and direction, temperature) for Stockton during the period 2000-2004 were obtained from the SJVAPCD's modeling website.[10,11] The Stockton monitoring station is located approximately 16 miles south-southeast of the project site. Upper air data from the Oakland International Airport monitoring station located approximately 56 miles southwest of the project site and approximately 60 miles west-southwest of the surface data station were used by SJVAPCD in creating the model-ready data set.

The surface characteristics appropriate to the land uses surrounding the meteorological station at Stockton (surface roughness length, albedo, and Bowen Ratio) were developed by SJVAPCD for the met station site following the guidance published by EPA in September 2005. Although this earlier guidance has been updated by EPA with the development of AERSURFACE (Version 08009) software (released on January 9, 2008), SJVAPCD staff believe that surface characteristics developed using AERSURFACE are not appropriate for use in the San Joaquin Valley. AERSURFACE obtains land use data from 1992 US Geological Survey National Land Cover Data. Because of the large amount of development in the valley since 1992, SJVAPCD staff believes that the land use data used by AERSURFACE is outdated. SJVAPCD staff has indicated that EPA staff has agreed that the older guidance can continue to be used for projects in the San Joaquin Valley.[12]

EPA requires the use of meteorological data that would be representative of atmospheric dispersion conditions at the source and at locations where the source may have a significant impact on air quality. Specifically, the meteorological data requirement originates in the Clean Air Act at Section 165(e)(1), which requires an analysis "of the ambient air quality at

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10 http://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm

11 In the June 5, 2008 comment letter, the SJVAPCD indicated that more than 10 percent of the meteorological data for year 2001 are missing, and that modeling results for that year should be used with caution. While all five years will be used in the modeling analyses, any modeling results based on 2001 met data will be flagged.

12 Villalvazo, Leland, personal communication with Eric Walther of Sierra Research, April 23, 2008.

the proposed site and in areas which may be affected by emissions from such facility for each pollutant subject to regulation under [the Act] which will be emitted from such facility."

This requirement and EPA's guidance on the use of onsite monitoring data are also outlined in the "*On-Site Meteorological Program Guidance for Regulatory Modeling Applications*" (1987b). The representativeness of the data depends on: (a) the proximity of the meteorological monitoring site to the area under consideration, (b) the complexity of the topography of the area, (c) the exposure of the meteorological sensors, and (d) the period of time during which the data are collected. District staff has determined that the Stockton meteorological data set is representative of conditions in the northern portion of San Joaquin County.[13] This area includes the project site. The SJVAB consists of a continuous intermountain valley approximately 250 miles long and averaging 80 miles wide. On the western edge of the Valley is the Coast Mountain range, with peaks reaching over 5,000 feet, and on the east side is the Sierra Nevada range with some peaks exceeding 14,000 feet. The Tehachapi Mountains form the southern boundary of the Valley. Terrain is open only at the northern end of the valley. Both the project site and the monitoring site are located near the northern end of the San Joaquin Valley, in the broad, flat center of the valley. There are no nearby large terrain features, such as hills or mountain ranges, to affect local wind flow patterns. Prevailing winds in the northern end of the valley are from the west through northwest on an annual basis, although there is a strong southeasterly component during the fall and winter months (see Appendix B for wind roses). Both the project site and the monitoring site are affected by the marine air that generally flows into the basin from the San Joaquin River Delta to the north. Based on these factors, we concur with SJVAPCD's conclusion that the wind direction and wind speed data collected at the Stockton meteorological monitoring stations are similar to the dispersion conditions at the project site and to the regional area. Thus, the Stockton meteorological data set satisfies the definition of representative data.

Representativeness has also been defined in the "*Workshop on the Representativeness of Meteorological Observations*" (Nappo et. al., 1982) as "the extent to which a set of measurements taken in a space-time domain reflects the actual conditions in the same or different space-time domain taken on a scale appropriate for a specific application." Representativeness is best evaluated when sites are climatologically similar, as are the project site and the Stockton meteorological monitoring station. Representativeness has additionally been defined in the PSD Monitoring Guideline (EPA, 1987a) as data that characterize the air quality for the general area in which the proposed project would be constructed and operated. As discussed above, because of the relative proximity of the Stockton meteorological data site to the proposed project site, the same large-scale topographic features that influence the meteorological data monitoring station also influence the proposed project site in the same manner.

5.1.5.6 Screening Modeling Analysis

To ensure the impacts analyzed were for maximum emission levels and worst-case dispersion conditions, a screening procedure was used to determine the inputs to the impact modeling for the new gas turbine. The screening procedure is used to identify the CTG/ HRSG operating conditions that would result in the maximum impacts on a pollutant-specific basis. The operating conditions examined in this screening analysis, along

[13] SJVAPCD, "Guidance for Dispersion Modeling," Working Draft, Rev 2.0, January 2007, p. 49. Available at http://www.valleyair.org/busind/pto/Tox_Resources/Modeling%20Guidance%20W_O%20Pic.pdf.

with their exhaust and emission characteristics, are shown in Appendix 5.1B, Table 5.1B-2R. These operating conditions represent CTG operation at maximum, average, and minimum ambient operating temperatures (94~~107.7~~°F, 61.2°F and 32.6~~23.7~~°F), and at full load~~, peak load (with duct firing),~~ and minimum load (50 percent).

Ambient impacts for each of the 6~~9~~ operating cases were modeled using EPA's AERMOD model and 5 years of Stockton meteorological data, as described above. The results of the unit impact analysis are presented in Appendix 5.1B, Table 5.1B-3R and summarized in Table 5.1-26R. The analysis showed that for short-term averaging periods and for 24-hour average SO_2, modeled impacts were highest under cold temperature, base~~peak~~ load operating conditions. For 24-hour average PM_{10}, impacts were highest under high~~cold~~ temperature, low load operating conditions, while annual average impacts were highest under high temperature, base load conditions.

TABLE 5.1-26R
Results of Turbine Screening Procedure: Turbine Operating Conditions Producing Maximum Modeled Ambient Impacts by Pollutant and Averaging Period

Pollutants and Averaging Periods	Operating Case
NO_x, SO_2 and CO: 1-, 3-, 8- and 24~~8~~-hour averages	Case 1~~3~~
~~SO_2 and~~ PM_{10}: 24-hour average~~s~~	Case 6~~2~~
NO_x, SO_2 and PM_{10}: annual averages	Case 5~~7~~

5.1.5.7 Refined Analysis

The screening modeling analysis described above was used to determine which CTG/HRSG operating parameters (emission rates and stack parameters) would be used in the subsequent refined analyses. The refined analyses are described in detail in the following sections.

5.1.5.7.1 Normal Operations Impact Analysis

The results of the AERMOD assessment for normal plant operations are summarized in Table 5.1-27R below. The following operating assumptions were used in developing the emission rates for each emissions unit and averaging period:

1-hour and 3-hour averages

- CTG/HRSG at base~~peak~~ load, cold temperature (maximum impact case from screening analysis)
- Auxiliary boiler in operation

8-hour average

- CTG/HRSG in startup for 6 hours and at base~~peak~~ load, cold temperature for two hours (maximum impact case from screening analysis)
- Auxiliary boiler in operation

24-hour average SO_2

- CTG/HRSG at base load, cold temperature for 24 hours (maximum impact case from screening analysis)
- Auxiliary boiler in operation[14]

24-hour average~~s~~ PM_{10}

- CTG/HRSG at minimum load, hot~~cold~~ temperature for 24 hours (maximum impact case from screening analysis)
- Auxiliary boiler in operation[15]~~, maximum daily emission rates~~~~[16]~~
- Cooling tower in operation

Annual Averages

- CTG/HRSG at base load, hot temperature (maximum impact case from screening analysis), maximum annual emission rates
- Auxiliary boiler in operation, maximum annual emission rates
- Cooling tower in operation, maximum annual emission rate

Emission rates and stack parameters used in the refined modeling analysis are shown in Appendix 5.1B, Table 5.1B-4R.

5.1.5.7.2 Startup and Shutdown Impacts Analysis

Short-term ambient impacts from the facility during turbine startup may be higher than impacts during normal operation because emission control systems are not fully operational during some part of the initial startup period when the turbine operates at low loads and the exhaust temperatures are low. Although the LEC gas turbine will use Flex Plant rapid startup~~Rapid Response~~ technology to minimize emissions during startup events, there are no in-use data available. Therefore, startup emissions and impacts were assessed using the very conservative assumption that there are no emissions or performance benefits from the Flex Plant ~~Rapid Response~~ technology. Turbine exhaust parameters for minimum load operation and under hot~~cold~~ temperature conditions were used to characterize CTG exhaust during startup, because that operating case produced the highest modeled impacts in the screening analysis. CO and NO_x emission rates from Table 5.1-19 were used. Startup impacts were evaluated for the 1-hour averaging period; startup impacts are included in the modeling of 8-hour average CO impacts under normal operating conditions (above). The emission rates and stack parameters used are shown in Table 5.1B-5R, Appendix 5.1B. The results of the analysis are summarized in Table 5.1-27R.

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14 The auxiliary boiler is expected to operate only when the CTG is starting up or shutting down. However, to preserve maximum operational flexibility, the AQIA assumes that the auxiliary boiler may also operate during normal plant operation for up to ~~12~~ 24 ~~total~~ hours per day

15 See footnote 14.

~~16 The auxiliary boiler is expected to operate only when the CTG is starting up or shutting down. However, to preserve maximum operational flexibility, the AQIA assumes that the auxiliary boiler may also operate during normal plant operation for up to 12 total hours per day.~~

5.1.5.7.3 Inversion Breakup Fumigation Modeling

Inversion breakup fumigation occurs when a stable layer of air lies a short distance above the release point of a plume and unstable air lies below. Under these conditions, an exhaust plume may be drawn to the ground, causing high ground-level pollutant concentrations. Although fumigation conditions rarely last as long as 1 hour, relatively high ground-level concentrations may be reached during that time. For this analysis, fumigation was assumed to occur for up to 90 minutes, per EPA guidance.

The SCREEN3 model was used to evaluate maximum ground-level concentrations for short-term averaging periods (24 hours or less). Guidance from EPA[17] was followed in evaluating fumigation impacts. The maximum fumigation impact from this analysis, which is shown in more detail in Appendix 5.1B, Table 5.1B-6R, showed that impacts under fumigation conditions are expected to be lower than the maximum concentrations calculated by AERMOD under downwash conditions. Fumigation impacts for the turbine occurred between 12~~10~~ km and ~~to~~ 18 km from the facility, depending upon turbine ~~engine~~ load (the AERMOD maximum 1-hour impact occurs about 1 km from the plant). Inversion breakup impacts are also shown in Table 5.1-27R.

5.1.5.8 Total Facility Impacts

The maximum facility impacts calculated from the modeling analyses described above are summarized in Table 5.1-27R. The highest modeled short-term impacts are expected to occur under startup conditions. ~~However, because the 1-hour average NO_2 impacts are driven by impacts from the auxiliary boiler, impacts under startup conditions are only marginally higher than impacts during normal turbine operation.~~

[17] EPA-454/R-92-019, "Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised."

TABLE 5.1-27R
Summary of Results from Refined Modeling Analysis for Permitted Sources

		Modeled Concentration ($\mu g/m^3$)		
Pollutant	**Averaging Time**	**Normal Operation**	**Inversion Breakup Fumigation**[a]	**Startup**
NO_2	1-hour[b]	10.1~~27.5~~	2.3~~2.9~~	28.5~~31.8~~
	annual	0.6~~0.3~~	--	--
SO_2	1-hour	3.8~~10.4~~	0.9~~1.1~~	--
	3-hours	2.4~~7.6~~	0.8~~1.0~~	--
	24-hours	1.4~~2.9~~	0.3~~0.5~~	--
	annual	0.2~~0.1~~	--	--
CO	1-hour	48.9~~132.9~~	2.1~~2.7~~	337.3~~323.8~~
	8-hours	110.2~~110.5~~	1.4~~1.9~~	--[c]
PM_{10}	24-hours	3.7[d]	0.9	--
	annual	0.6~~0.9~~	--	--

[a]Inversion breakup is a short-term phenomenon and does not affect annual impacts.
[b]1-hour average NO_2 impacts were ozone-limited using PVMRM.
[c]Included in 8-hour impacts for normal operations.
[d]~~Highest impact for 2001 met data. Second highest concentration is 3.3 µg/m3 based on 2004 met data.~~

To determine a project's air quality impacts, the modeled concentrations are added to the highest reported background ambient air concentrations and then compared to the applicable ambient air quality standards. The highest reported background ambient concentrations were discussed in Section 5.1.1.3 and the monitored concentrations during the past 3 years are shown in the Table 5.1-28. More detailed discussions of why the data collected at these stations are representative of ambient concentrations in the vicinity of the project are provided in Sections 5.1.1.3.2 and 5.1.7.

TABLE 5.1-28
Highest Reported Background Concentrations in the Project Area

Pollutant	Averaging Period	2005	2006	2007
NO_2	1 hour	163.6	135.4	131.6
	annual	32.1	34.0	30.2
SO_2	1 hour	46.8	23.4	44.2
	3 hour	15.6	13.0	28.6
	24 hour	7.9	7.9	10.8
	annual	2.7	2.7	2.7
CO	1 hour	5,375	5,500	4,500
	8 hour	3,178	2,500	2,567
PM_{10}	24 hour	84	85	75
	annual	29.4	33.4	27.7
$PM_{2.5}$	24 hour	44	42	48
	annual	12.5	13.1	12.9

Maximum ground-level impacts due to operation of the LEC are shown together with the ambient air quality standards in Table 5.1-29R. The ambient air quality modeling results are extremely conservative and are designed to overpredict ambient concentrations because they evaluate impacts under a combination of worst-case conditions that are unlikely to occur simultaneously. The modeling combines the highest allowable emission rates with the most extreme meteorological conditions and the equipment operating load conditions that result in the highest ambient impact. Therefore it is extremely unlikely that the ambient concentrations predicted by the models will ever actually be realized. However, this analysis demonstrates that even under these combinations of conditions that overpredict impacts, the LEC will not cause or contribute to violations of any state or federal air quality standards, with the exception of the state PM_{10} and state and federal $PM_{2.5}$ standards. For this pollutant, existing concentrations already exceed the standards. However, the modeling results in Table 5.1-27R demonstrate that the project PM_{10} and $PM_{2.5}$ impacts will be below significant impacts levels of 5 µg/m³ for the 24-hour averaging period and 1.0 µg/m³ for the annual averaging period. Therefore, the proposed project will not contribute significantly to these exceedances.

TABLE 5.1-29R
Modeled Maximum Impacts Plus Background

Pollutant	Averaging Time	Maximum Facility Impact (µg/m³)	Background (µg/m³)	Total Impact (µg/m³)	State Standard (µg/m³)	Federal Standard (µg/m³)
NO_2	1-hour*	28.5 ~~3.8~~	163.6	192.1 ~~195.4~~	338	–
	Annual	0.6 ~~0.3~~	34.0	34.6 ~~34.3~~	–	100
SO_2	1-hour	3.8 ~~10.4~~	46.8	50.6 ~~57.2~~	650	–
	3-hour	2.4 ~~7.6~~	28.6	31.0 ~~36.2~~	–	1300
	24-hour	1.4 ~~2.9~~	10.8	12.2 ~~13.7~~	109	365
	Annual	0.2 ~~0.1~~	2.7	2.9 ~~2.8~~	–	80
CO	1-hour	337 ~~324~~	5,500	5,837 ~~5,824~~	23,000	40,000
	8-hour	110 ~~111~~	3,178	3,288 ~~3,289~~	10,000	10,000
PM_{10}	24-hour	3.7	85	88.7	50	150
	Annual	0.6 ~~0.9~~	33.4	34.0 ~~34.3~~	20	–
$PM_{2.5}$	24-Hour	3.7	48	51.7	–	35
	Annual	0.6 ~~0.9~~	13.1	13.7 ~~14.0~~	12	15

*Includes startup. Under normal operating conditions, total impact will be 10.1 ~~27.5~~ µg/m³.

5.1.5.9 Commissioning Impacts Analysis

The commissioning period begins when the CTG and HRSG are prepared for first fire and ends upon successful completion of initial performance testing. There are several high-emissions scenarios possible during commissioning. The first is the period prior to SCR system and oxidation catalyst installation, when the gas turbine combustion system is being tuned. Under this scenario, NO_x emissions would be high because the NO_x emissions control system would not be functioning and because the gas turbine would not be tuned for optimum performance. CO emissions would also be high because turbine performance would not be optimized and the CO emissions control system would not be functioning. The second high emissions scenario may occur when the gas turbine has been tuned but the SCR and oxidation catalyst installation is not complete. Since the control system installation would not be complete, NO_x and CO levels would again be high. Commissioning activities and expected emissions are shown in more detail in Table 5.1B-7R, Appendix 5.1B.

The existing NCPA Lodi generating unit will be in operation during the commissioning of the LEC. An assessment of the air quality impacts of this combined operation have been included in the cumulative impacts analysis, provided in Appendix 5.1G.

Air quality impacts during the commissioning period were determined using the emission rates in Table 5.1B-7R. One-hour average NO_2 impacts during commissioning were modeled using AERMOD_OLM and concurrent Stockton ozone data. Modeled impacts are shown in Table 5.1-30R.

TABLE 5.1-30R
Modeled Maximum Impacts During Commissioning of the CTG/HRSG

Pollutant	Averaging Time	Maximum Facility Impact (µg/m³)	Background (µg/m³)	Total Impact (µg/m³)	State Standard (µg/m³)	Federal Standard (µg/m³)
NO_2	1-hour	47.8 ~~36.4~~	163.6	211 ~~200~~	338	–
CO	1-hour	748.6 ~~718.2~~	5,500	6,249 ~~6,218~~	23,000	40,000
	8-hour	526.2 ~~535.0~~	3,178	3,704 ~~3,713~~	10,000	10,000

5.1.6 Laws, Ordinances, Regulations, and Standards

The EPA has responsibility for enforcing, on a national basis, the requirements of many of the country's environmental and hazardous waste laws. California is under the jurisdiction of EPA Region 9, which has its offices in San Francisco. Region 9 is responsible for the local administration of EPA programs for California, Arizona, Nevada, Hawaii, and certain Pacific trust territories. EPA's activities relative to the California air pollution control program focus principally on reviewing California's submittals for the State Implementation Plan (SIP). The SIP is required by the federal Clean Air Act to demonstrate how all areas of the state will meet the national ambient air quality standards within the federally specified deadlines (42 USC §7409, 7411).

The CARB was created in 1968 by the Mulford-Carrell Air Resources Act, through the merger of two other state agencies. The CARB's primary responsibilities are to develop, adopt, implement, and enforce the state's motor vehicle pollution control program; to administer and coordinate the state's air pollution research program; to adopt and update as necessary the state's ambient air quality standards; to review the operations of the local air pollution control districts; and to review and coordinate preparation of the SIP for achievement of the federal ambient air quality standards (California Health & Safety Code (H&SC) §39500 et seq.).

When the state's air pollution statutes were reorganized in the mid-1960s, local air pollution control districts (APCDs) were required to be established in each county of the state (H&SC §4000 et seq.). There are three different types of districts: county, regional, and unified. In addition, special air quality management districts (AQMDs), with more comprehensive authority over non-vehicular sources as well as transportation and other regional planning responsibilities, have been established by the Legislature for several regions in California (H&SC §40200 et seq.).

APCDs and AQMDs in California have principal responsibility for:

- Developing plans for meeting the state and federal ambient air quality standards;
- Developing control measures for non-vehicular sources of air pollution necessary to achieve and maintain both state and federal air quality standards;
- Implementing permit programs established for the construction, modification, and operation of sources of air pollution; and
- Enforcing air pollution statutes and regulations governing non-vehicular sources, and for developing employer-based trip reduction programs.

Each level of government has adopted specific regulations that limit emissions from stationary combustion sources, several of which are applicable to this project.

5.1.6.1 Federal LORS

The EPA implements and enforces the requirements of many of the federal environmental laws. The federal Clean Air Act, as most recently amended in 1990, provides EPA with the legal authority to regulate air pollution from stationary sources such as the project. EPA has promulgated the following stationary source regulatory programs to implement the requirements of the 1990 Clean Air Act:

- Standards of Performance for New Stationary Sources (NSPS)
- National Emission Standards for Hazardous Air Pollutants (NESHAPS)
- Prevention of Significant Deterioration (PSD)
- New Source Review (NSR)
- Title IV: Acid Deposition Control
- Title V: Operating Permits

National Standards of Performance for New Stationary Sources

Authority: Clean Air Act §111, 42 USC §7411; 40 CFR Part 60, Subpart KKKK

Purpose: Establishes standards of performance to limit the emission of criteria pollutants (air pollutants for which EPA has established national ambient air quality standards) from new or modified facilities in specific source categories. The applicability of these regulations depends on the equipment size; process rate; and date of construction, modification, or reconstruction of the affected facility. The project is subject to the following NSPS:

Subpart KKKK, Standards of Performance for Stationary Gas Turbines (constructed after February 18, 2005) is applicable to the combined-cycle gas turbine and fired waste-heat recovery boiler; and

Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units), which applies to boilers that burn fossil fuel with a heat input capacity equal to or less than 100 MMBtu/hr and greater than or equal to 10 MMBtu/hr, is applicable to the auxiliary boiler.

These standards are implemented at the local level with federal and state oversight.

Administering Agency: SJVAPCD, with EPA Region 9 and CARB oversight.

National Emission Standards for Hazardous Air Pollutants

Authority: Clean Air Act § 112, 42 USC §7412; 40 CFR Part 63

Purpose: Establishes national emission standards to limit emissions of hazardous air pollutants (HAPs, or air pollutants identified by EPA as causing or contributing to the adverse health effects of air pollution but for which NAAQS have not been established) from facilities in specific source categories.[18] These standards are implemented at the local level with federal oversight. Only the NESHAP for combustion turbines, which limits formaldehyde emissions from turbines, is potentially applicable to the proposed project. However, as discussed further below, this NESHAP is not applicable to the proposed project because the facility would not be a major source of HAPs (i.e., 10 tpy of one HAP or 25 tpy of all HAPs). Thus, NESHAPs requirements will not be addressed further.

Administering Agency: SJVAPCD, with EPA Region 9 oversight.

Prevention of Significant Deterioration Program

Authority: Clean Air Act §160-169A, 42 USC §7470-7491; 40 CFR Parts 51 and 52

Purpose: Requires pre-construction review and permitting of new or modified major stationary sources of air pollution to prevent significant deterioration of ambient air quality. PSD applies to pollutants for which ambient concentrations do not exceed the corresponding NAAQS (i.e., attainment pollutants). The PSD program allows new sources of air pollution to be constructed, or existing sources to be modified, while preserving the existing ambient air quality levels, protecting public health and welfare, and protecting Class I areas (e.g., national parks and wilderness areas).

The PSD requirements apply, on a pollutant-specific basis, to any project that is a new major stationary source or a major modification to an existing major stationary source. A major source is a listed facility (one of 28 PSD source categories listed in the federal Clean Air Act) that emits at least 100 tpy, or any other facility that emits at least 250 tpy.

The PSD program contains the following elements:

- Air quality monitoring
- BACT
- Air quality impact analysis
- Protection of Class I areas
- Growth, visibility, soils, and vegetation impacts

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[18] A major source of HAPs is one that emits more than 10 tons per year (tpy) of any individual HAP, or more than 25 tpy of all HAPs combined.

Although the existing power plant is not a major stationary source, the proposed project itself will result in emissions exceeding the applicable PSD thresholds for NO_2, ~~and~~ CO and PM_{10}[19] emitted from this source category[20] listed in the federal PSD regulations (40 CFR 52.21). Therefore, the proposed project is subject to PSD review. As the SJVAPCD does not have delegation for the PSD program, a separate PSD application is being filed with the EPA.

Air Quality Monitoring

At its discretion, EPA Region 9 may require pre-construction and/or post-construction ambient air quality monitoring for PSD sources if representative monitoring data are not already available. Pre-construction monitoring data must be gathered over a one-year period to characterize local ambient air quality. Post-construction air quality monitoring data must be collected as deemed necessary by EPA Region 9 to characterize the impacts of proposed project emissions on ambient air quality.

Best Available Control Technology

BACT must be applied to any new or modified major source to minimize the emissions increase of those pollutants exceeding the PSD emission thresholds. EPA defines BACT as an emissions limitation based on the maximum degree of reduction for each subject pollutant, considering energy, environmental, and economic impacts, that is achievable through the application of available methods, systems, and techniques. BACT must be as stringent as any emission limit required by an applicable NSPS or NESHAP. BACT is defined below in the discussion of the SJVAPCD NSR regulatory requirements.

Air Quality Impact Analysis

An air quality dispersion analysis must be conducted to evaluate impacts of significant emission increases from new or modified facilities on ambient air quality. PSD source emissions must not cause an exceedance of any ambient air quality standard, and the increase in ambient air concentrations must not exceed the allowable increments shown in Table 5.1-31.

TABLE 5.1-31
PSD Class II Increments

Pollutant	Averaging Period	Allowable Increment ($\mu g/m^3$)
NO_2	Annual	25[a]
PM_{10}	Annual	17[a]
	24-Hour	30[b]
SO_2	Annual	20[a]
	24-Hour	91[b]
	3-Hour	512[b]

[a]Not to be exceeded

[b]Not to be exceeded more than once per year.

19 ~~While~~ EPA made a "determination of attainment" of the federal PM_{10} standard for the San Joaquin Valley Air Basin on October 30, 2006, and ~~the EPA has not yet~~ "redesignated" the basin as attainment for PM_{10} (with an effective date of December 12, 2008~~see 73 FR 22307; April 25, 2008~~). Therefore, PSD requirements are now ~~not~~ applicable for PM_{10}.

20 Fossil fuel-fired steam-electric plant with heat input greater than 250 MMBtu/hour.

Protection of Class I Areas

The potential increase in ambient air quality concentrations for attainment pollutants (i.e., NO_2, PM_{10}, or SO_2) within Class I areas closer than approximately 100 km may need to be quantified if the new or modified PSD source were to have a sufficiently large emission increase as evaluated by the Class I area Federal Land Managers. In such a case, a Class I visibility impact analysis would also be performed.

Growth, Visibility, Soils, and Vegetation Impacts

Impairment to visibility, soils, and vegetation resulting from PSD source emissions as well as associated commercial, residential, industrial, and other growth must be analyzed. This analysis includes cumulative impacts to local ambient air quality.

Administering Agency: EPA, Region 9.

Nonattainment New Source Review

Authority: Clean Air Act §171-193, 42 USC §7501 et seq.; 40 CFR Parts 51 and 52

Purpose: Requires pre-construction review and permitting of new or modified major stationary sources of air pollution to allow industrial growth without interfering with the attainment and maintenance of ambient quality standards. In general, this program is implemented at the local level with EPA oversight. EPA recently promulgated new source review requirements for major sources of $PM_{2.5}$ for nonattainment areas that do not have federally approved SIPs, and EPA is responsible for implementing these requirements (see 73 FR 28231; May 16, 2008). Because the LEC is not a major source of $PM_{2.5}$ (i.e., the facility has a maximum potential to emit of less than 100 tons per year of $PM_{2.5}$), the facility is not subject to federal new source review requirements for $PM_{2.5}$.

Administering Agency: SJVAPCD, with EPA Region 9 oversight.

Title IV – Acid Rain Program

Authority: Clean Air Act §401, 42 USC §7651 et seq.; 40 CFR Part 72

Purpose: Requires the monitoring and reporting of emissions of acidic compounds and their precursors. The principal source of these compounds is the combustion of fossil fuels. Therefore, Title IV established national standards to monitor, record, and, in some cases, limit SO_2 and NOx emissions from electrical power generating facilities. These standards are implemented at the local level with federal oversight.

Administering Agency: SJVAPCD, with EPA Region 9 oversight.

Title V – Operating Permits Program

Authority: Clean Air Act § 501 (Title V), 42 USC §7661; 40 CFR Part 70

Purpose: Requires the issuance of operating permits that identify all applicable federal performance, operating, monitoring, recordkeeping, and reporting requirements. Title V applies to major facilities, Phase II acid rain facilities, subject solid waste incinerator facilities, and any facility listed by EPA as requiring a Title V permit. These requirements are implemented at the local level with federal oversight.

Administering Agency: SJVAPCD, with EPA Region 9 oversight.

5.1.6.2 State LORS

The CARB was created in 1968 by the Mulford-Carrell Air Resources Act, through the merger of two other state agencies. The CARB's primary responsibilities are to develop, adopt, implement, and enforce the state's motor vehicle pollution control program; to administer and coordinate the state's air pollution research program; to adopt and update, as necessary, the state's ambient air quality standards; to review the operations of the local air pollution control districts; and to review and coordinate preparation of the SIP for achievement of the federal ambient air quality standards. The CARB has implemented the following state or federal stationary source regulatory programs in accordance with the requirements of the federal Clean Air Act and California H&SC:

- State Implementation Plan
- California Clean Air Act
- Toxic Air Contaminant Program
- Nuisance Regulation
- Air Toxics "Hot Spots" Act
- CEC and CARB Memorandum of Understanding
- California Climate Change Regulatory Program

State Implementation Plan

Authority: H&SC §39500 et seq.

Purpose: Required by the federal Clean Air Act, the SIP must demonstrate the means by which all areas of the state will attain and maintain NAAQS within the federally mandated deadlines. The CARB reviews and coordinates preparation of the SIP. Local districts must adopt new rules (and/or revise existing rules) and demonstrate that the resulting emission reductions, in conjunction with reductions in mobile source emissions, will result in the attainment of NAAQS. The relevant SJVAPCD Rules and Regulations that have also been incorporated into the SIP are discussed with the local LORS.

Administering Agency: SJVAPCD, with CARB and EPA Region 9 oversight.

California Clean Air Act

Authority: H&SC §40910 – 40930

Purpose: Established in 1989, the California Clean Air Act requires local districts to attain and maintain both national and state ambient air quality standards at the "earliest practicable date." Local districts must prepare air quality plans demonstrating the means by which the ambient air quality standards will be attained and maintained. The SJVAPCD Air Quality Plan is discussed with the local LORS.

Administering Agency: SJVAPCD, with CARB oversight.

Toxic Air Contaminant Program

Authority: H&SC §39650 – 39675

Purpose: Established in 1983, the Toxic Air Contaminant Identification and Control Act created a two-step process to identify toxic air contaminants and control their emissions. The CARB identifies and prioritizes the pollutants to be considered for identification as toxic air contaminants. The CARB also assesses the potential for human exposure to a substance, while the Office of Environmental Health Hazard Assessment (OEHHA) evaluates the corresponding health effects. Both agencies collaborate in the preparation of a risk assessment report, which concludes whether a substance poses a significant health risk and should be identified as a toxic air contaminant. In 1993, the Legislature amended the program to identify the 187 federal hazardous air pollutants[21] as toxic air contaminants. The CARB reviews the emission sources of an identified toxic air contaminant and, if necessary, develops air toxics control measures to reduce the emissions.

Nuisance Regulation

Authority: CA Health & Safety Code §41700

Purpose: Provides that "no person shall discharge from any source whatsoever such quantities of air contaminants or other material which causes injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause injury or damage to business or property."

Administering Agency: SJVAPCD and CARB

Air Toxic "Hot Spots" Act

Authority: CA Health & Safety Code § 44300-44384; 17 CCR §93300-93347

Purpose: Established in 1987, the Air Toxics "Hot Spots" Information and Assessment Act[22] supplements the toxic air contaminant program, by requiring the development of a statewide inventory of air toxics emissions from stationary sources. The program requires affected facilities to prepare (1) an emissions inventory plan that identifies relevant air toxics and sources of air toxics emissions; (2) an emissions inventory report quantifying air toxics emissions; and (3) a health risk assessment, if necessary, to characterize the health risks to the exposed public. Facilities whose air toxics emissions are deemed to pose a significant health risk must issue notices to the exposed population. In 1992, the Legislature amended the program to further require facilities whose air toxics emissions are deemed to pose a significant health risk to implement risk management plans to reduce the associated health risks. This program is implemented at the local level with state oversight.

Administering Agency: SJVAPCD, with CARB oversight.

CEC and CARB Memorandum of Understanding

Authority: CA Pub. Res. Code § 25523(a); 20 CCR §1752, 1752.5, 2300-2309, and Div. 2, Chap. 5, Art. 1, Appendix B, Part (k)

21 The EPA increased the original list of 188 HAPs to 189, and then removed Caprolactam (61FR30816, June 18, 1996) and methyl ethyl ketone on December 19, 2005, reducing the list back to 187.

22 Commonly known as AB 2588.

Purpose: Establishes requirements in the CEC's decision-making process for an AFC that assures protection of environmental quality. The AFC is required to include information concerning air quality protection.

Administering Agency: CEC.

California Climate Change Regulatory Program

Authority: Stats. 2006, Ch. 488 and CA Health & Safety Code § 38500-38599

Purpose: The State of California adopted the Global Warming Solutions Act of 2006 (Assembly Bill [AB] 32) on September 27, 2006, which requires sources within the state to reduce carbon emissions by approximately 25% by the year 2020. The California Climate Action Registry had already published protocols for voluntary reporting of GHG emissions from a number of sectors of the economy,[23] and the CARB has proposed draft regulations to limit GHG emissions from electric power plants and other specific source categories.[24] In addition, the CARB has issued draft guidance with recommended emission factors for calculating GHG emissions.[25]

AB 32 also sets the following milestone dates for the CARB to take specific actions:

June 30, 2007: Identify a list of discrete early action GHG emission reduction measures (first report published April 20, 2007, with additional measures adopted on October 25, 2007).

January 1, 2008: Establish a statewide GHG emission cap for 2020 that is equivalent to 1990 emissions.

January 1, 2008: Adopt mandatory reporting rules for significant sources of GHGs.

January 1, 2009: Adopt a scoping plan that will indicate how GHG emission reductions will be achieved from significant GHG sources through regulations, market-based compliance mechanisms, and other actions, including recommendation of a de minimis threshold for GHG emissions, below which sources would be exempt from reduction requirements.

January 1, 2011: Adopt regulations to achieve maximum technologically feasible and cost-effective GHG emission reductions, including provisions for both market-based and alternative compliance mechanisms.

January 1, 2012: Regulations adopted prior to January 1, 2010, become effective.

Senate Bill (SB) 97, adopted August 21, 2007, requires the California Office of Planning and Research (OPR) to develop CEQA guidelines "for the mitigation of GHG emissions or the effects of GHG emissions" by July 1, 2009. SB 97 further requires the Resources Agency Secretary to adopt these CEQA guidelines by January 1, 2010. Finally, SB 97 removes GHG

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23 California Climate Action Registry. Appendix to the General Reporting Protocol: Power/Utility Reporting Protocol – Reporting Entity-Wide Greenhouse Gas Emissions Produced by Electric Power Generators and Electric Utilities, Version 1.0, April 2005 (http://www.climateregistry.org/Default.aspx?refreshed=true).

24 CARB. Staff Report: Initial Statement of Reasons for Rulemaking, Public Hearing to Consider Mandatory Reporting of Greenhouse Gas Emissions Pursuant to the California Global Warming Solutions Act of 2006 (Assembly Bill 32), October 19, 2007, http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm.

25 CARB. Attachments C to F, Supplemental Materials Document for Staff Report: Initial Statement of Reasons for Rulemaking, Public Hearing to Consider Mandatory Reporting of Greenhouse Gas Emissions Pursuant to the California Global Warming Solutions Act of 2006 (Assembly Bill 32), October 19, 2007, http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm

emissions as a cause of action under CEQA for specified state-financed infrastructure projects until January 1, 2010.

The AFC is required to include the project's emission rates of "greenhouse gases" (CO_2, CH_2, N_2O, and SF_6) from the stack, cooling towers, fuels and materials handling processes, delivery and storage systems, and from all on-site secondary emission sources."[26]

On January 25, 2007, the PUC and CEC jointly adopted an interim Greenhouse Gas Emissions Performance Standard (EPS) in an effort to help mitigate climate change. The EPS is a facility-based emissions standard requiring that all new long-term commitments for baseload generation to serve California consumers be with power plants that have emissions no greater than a combined-cycle gas turbine plant. That level is established at 1,100 pounds of CO_2 per megawatt-hour.[27]

Administering Agencies: CARB and CEC.

5.1.6.3 Local LORS

When the state's air pollution statutes were reorganized in the mid-1960s, local districts were required to be established in each county of the state. There are three different types of districts: county, regional, and unified (including the SJVAPCD). Local districts have principal responsibility for developing plans for meeting the NAAQS and California ambient air quality standards; for developing control measures for non-vehicular sources of air pollution necessary to achieve and maintain both state and federal air quality standards; for implementing permit programs established for the construction, modification, and operation of sources of air pollution; for enforcing air pollution statutes and regulations governing non-vehicular sources; and for developing programs to reduce emissions from indirect sources.

San Joaquin Valley Unified Air Pollution Control District Attainment Demonstration Plans

Authority: H&SC §40914

Purpose: The SJVAPCD plans define the proposed strategies, including stationary source and transportation control measures and new source review rules, which will be implemented to attain and maintain the state ambient air quality standards. The relevant stationary source control measures and new source review requirements are discussed with individual SJVAPCD Rules and Regulations.

Administering Agency: SJVAPCD, with CARB oversight.

San Joaquin Valley Air Pollution Control District Rules and Regulations

Authority: H&SC §4000 et seq., H&SC §40200 et seq., indicated SJVAPCD Rules

Purpose: Establishes procedures and standards for issuing permits; establishes standards and limitations on a source-specific basis.

Administering Agency: SJVAPCD with EPA Region 9 and CARB oversight.

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26 Appendix B (g) (8) (E) of the CEC siting regulations.

27 http://www.cpuc.ca.gov/PUC/061211_egyleadership.htm. Statutory authority based on Senate Bill 1368 (Stats. 2006, Ch. 598 and CA Public Utilities Code § 8340-8341). The numerical limit of 1,100 lbs CO_2 per MW-hr originated in PUC Interim Decision 07-01-039.

Rule 2010 (Permits Required) specifies that any facility installing nonexempt equipment that causes or controls the emission of air pollutants must first obtain an Authority to Construct from the SJVAPCD. Under Section 5.8.8 of Rule 2201 (New and Modified Stationary Source Review Rule), the SJVAPCD's Final Determination of Compliance acts as an authority to construct for a power plant upon approval of the project by the CEC.

Rule 2201 (New and Modified Stationary Source Review Rule) implements the federal NSR program, as well as the new source review requirements of the California Clean Air Act. The rule contains the following elements:

- Best available control technology (BACT)
- Emission offsets
- Air quality impact analysis (AQIA)

Best Available Control Technology

Best Available Control Technology (BACT) must be applied to any new or modified source resulting in an emissions increase exceeding any SJVAPCD BACT threshold shown in Table 5.1-32.

TABLE 5.1-32
District BACT Emission Thresholds

Pollutant	Threshold
PM	2 lb/day
NO_x	2 lb/day
SO_2	2 lb/day
VOC	2 lb/day
CO	2 lb/day

Source: Rule 2201, Section 4.1. Per Section 4.2,1, CO BACT threshold not applicable to facilities with total CO emissions less than 200,000 lb/year.

The SJVAPCD defines BACT as the most stringent emission limitation or control technique that:

- Has been achieved in practice for such emissions unit and class of source; or
- Is contained in any SIP approved by the EPA for such emissions unit category and class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed emissions unit demonstrates to the satisfaction of the Air Pollution Control Officer (APCO) that such limitation or control technique is not presently achievable; or
- Is any other emission limitation or control technique, including process and equipment changes of basic and control equipment, found by the APCO to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as determined by the APCO.

Emission Offsets

A new or modified facility with a stationary source NSR balance exceeding the SJVAPCD offset thresholds shown in Table 5.1-33 must offset all emissions increases at a ratio that varies according to the distance between the facility and the source of the offsets.

TABLE 5.1-33
District Offset Emission Thresholds

Pollutant	Threshold, lb/yr
NO_x	20,000
SO_2	54,730
CO	200,000*
VOC	20,000
PM	29,200

*Applies in CO attainment areas, including the project site. CO emissions in nonattainment areas are subject to a 30,000 lb/yr offset threshold.

Air Quality Impact Analysis

An air quality impact analysis must be conducted to evaluate impacts of emission increases from new or modified facilities on ambient air quality. Project emissions must not cause an exceedance of any ambient air quality standard.

Toxic Risk Management

The SJVAPCD's Risk Management Review Policy for Permitting New and Modified Sources provides a mechanism for evaluating potential impacts of air emissions of toxic substances from new, modified, and relocated sources in the SJVAPCD. The policy requires a demonstration that the source will not adversely impact the health and welfare of the public.

CEC Review

Rule 2201, Section 5.8 establishes a procedure for coordinating SJVAPCD review of power plant projects with the CEC AFC and Small Power Plant Exemption (SPPE) processes. Under this rule, the SJVAPCD reviews the AFC/SPPE and issues a Determination of Compliance for a proposed project, which is equivalent to an Authority to Construct upon approval of the project by the CEC. A permit to operate is issued following the CEC's certification of a project and demonstration of compliance with all permit conditions.

Rule 2540 (Acid Rain Program) requires that certain subject facilities comply with maximum operating emissions levels for SO_2 and NO_x, and must monitor SO_2, NO_x, and CO_2 emissions and exhaust gas flow rates. A Phase II acid rain facility, such as the project, must obtain an acid rain permit as mandated by Title IV of the 1990 Clean Air Act Amendments. A permit application must be submitted to the SJVAPCD at least 24 months before operation of the new unit commences.[28] The application must present all relevant Phase II sources at the facility, a compliance plan for each unit, applicable standards, and an estimated commencement date of operations.

28 Approximately by June 1, 2010, based on the assumption of initial operation on June 1, 2012.

Rule 2520 (Federally Mandated Operating Permits) requires major facilities and Phase II acid rain facilities undergoing modifications to obtain an operating permit containing the federally enforceable requirements mandated by Title V of the 1990 Clean Air Act Amendments. A permit amendment application for a modification to an existing Title V facility must be submitted and an amended permit issued by the SJVAPCD prior to commencing operations at the facility. The application must present a process description, all new stationary sources at the facility, applicable regulations, estimated emissions, associated operating conditions, alternative operating scenarios, a facility compliance plan, and a compliance certification.

SJVAPCD Prohibitory Rules

The general prohibitory rules of the SJVAPCD applicable to the project include the following:

Rule 4001 (New Source Performance Standards) requires compliance with applicable federal standards of performance for new or modified stationary sources.

Subpart KKKK (Standards of Performance for Stationary Combustion Turbines) applies to gas turbines with a heat input in excess of 1 MMBtu/hr that commence construction after February 18, 2005. Subpart KKKK limits NO_x and SO_2 emissions from new gas turbines (and associated heat recovery steam generators) based on power output. The limits for turbines greater than 30 MW are 0.39 lb NO_x per MW-hr and 0.58 lb SO_2 per MW-hr.

Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units) applies to boilers that burn fossil fuel with a heat input capacity equal to or less than 100 MMBtu/hr and greater than or equal to 10 MMBtu/hr, and therefore would apply to the proposed project's 65 MMBtu/hr auxiliary boiler.

Rule 4002 – National Emissions Standards for Hazardous Air Pollutants: This rule implements the federal NESHAPS regulations discussed above in Section 5.1.6.1. The combustion turbine NESHAP is not applicable to the proposed project because the facility will not be a major source of HAPs (i.e., 10 tpy of one HAP or 25 tpy of all HAPs).

Rule 4101 – Visible Emissions: Prohibits visible emissions as dark or darker than Ringelmann No. 1 for periods greater than three minutes in any hour.

Rule 4102 – Nuisance: Prohibits the discharge from a facility of air pollutants that cause injury, detriment, nuisance, or annoyance to the public, or that damage business or property.

Rule 4201 – Particulate Matter Emission Standards: Prohibits PM emissions in excess of 0.1 grains per dry standard cubic foot (gr/dscf).

Rule 4301 – Fuel Burning Equipment: For "any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer" (i.e., applies to auxiliary boiler, but not to gas turbines, or emergency standby generator and fire water pump engines), combustion contaminant (defined in Rule 1020 (Definition 3.12) as particulate matter from burning carbon-containing material) emissions are limited to:

- 0.1 grain of combustion contaminants per dry standard cubic foot @ 12% CO_2
- 10 pounds of combustion contaminants per hour

- Sulfur compounds as SO_2 to 200 pounds per hour
- NO_x as NO_2 to 140 pounds per hour

Rule 4305 – Boilers, Steam Generators, and Process Heaters Phase 2: Limits emissions from this equipment as follows:

- Gas-fired NO_x emissions to 30 ppmvd @ 3% O_2 (0.036 lb/MMBtu)
- CO emissions to 400 ppmvd @ 3% O_2

The rule also requires installation of CEMs for NO_x, CO and O_2.

Rule 4306 – Boilers, Steam Generators, and Process Heaters Phase 3: Limits emissions from this equipment as follows:

- Category H boiler (i.e., annual heat input between 9 and 30 billion Btu/year) gas-fired NO_x emissions to 30 ppmvd @ 3% O_2 (0.007 lb/MMBtu) for the Standard Option, required by December 1, 2008, or
- Category B boiler (i.e., heat input > 20 MMBtu/hr, except Category H) gas-fired NO_x emissions to 6 ppmvd @ 3% O_2 (0.007 lb/MMBtu) for the Enhanced Option, required by June 1, 2007, and
- CO emissions to 400 ppmvd @ 3% O_2.

The rule also requires installation of CEMs for NO_x, CO, and O_2

However, SJVAPCD has proposed to amend Rule 4306, Phase 3, and replace it with Rule 4320, described further below.

Rule 4320 – Advanced Emission Reduction Options For Boilers, Steam Generators, And Process Heaters Greater Than 5.0 MMBtu/hr: Limits emissions from this equipment as follows:

- Category B boiler (i.e., heat input > 20 MMBtu/hr, except Category E) gas-fired NO_x emissions to 7 ppmvd @ 3% O_2 (0.007 lb/MMBtu) by January 1, 2012, or 5 ppmv or 0.0062 lb/MMBtu by January 1, 2013, or
- Category E boiler (i.e., annual heat input between 1.8 and 9 billion Btu/year) gas-fired NO_x emissions to 30 ppmvd @ 3% O_2 (0.007 lb/MMBtu) for the Standard Option, required by January 1, 2014; and
- CO emissions to 400 ppmvd @ 3% O_2.

The draft rule would also provide the option of paying an emissions fee in lieu of achieving the NO_x limits in the rule. Finally, the draft rule would also require use of a CEMS for NO_x, CO, and O_2 or implementation of an APCO-approved Alternate Monitoring System, as well as the use of an approved parametric monitoring system to track SO_x and PM_{10} emissions.

Rule 4351 – Boilers, Steam Generators, and Process Heaters Phase 1: Limits emissions from this equipment as follows:

- Gas-fired NO_x emissions to 90 ppmvd @ 3% O_2 (0.10 lb/MMBtu)

- CO emissions to 400 ppmvd @ 3% O_2.

The rule also requires monitoring of any NO_x control system

Rule 4703 – Stationary Gas Turbines: Limits emissions from stationary gas turbines as follows:

- NO_x (Tier 2) emissions from combined-cycle stationary gas turbines rated > 10 MW to 3 ppmvd @15% O_2 for Enhanced Compliance Option, required after April 30, 2008
- CO for ~~GE Frame 7~~ gas turbines not identified in Table 5-4 of the rule to 200~~25~~ ppmv 15% O_2.

Rule 4703 also limits turbine startup periods to 2 hours unless a longer period is approved by SJVAPCD, EPA and CARB.

Rule 4801 – Sulfur Compounds: Prohibits sulfur compound emissions, calculated as SO_2, in excess of 0.2% (2,000 ppmv) from any source.

Rule 8011 – Fugitive PM_{10} Prohibitions, General Requirements: Sets forth definitions, applicability and administrative requirements for anthropogenic sources of PM_{10}.

Rule 8021 – Fugitive PM10 Prohibitions, Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities: Limits fugitive dust emissions from construction, demolition, excavation, and related activities.

Rule 8041 – Carryout and Trackout (Fugitive PM_{10} Prohibitions): Requires application of specific measures to minimize fugitive dust emissions from construction carryout and trackout.

Rule 8051 – Open Areas (Fugitive PM_{10} Prohibitions): Requires application of specific measures to minimize fugitive dust emissions from open areas larger than 3.0 acres containing more than 1,000 square feet of disturbed surface.

Rule 8061 – Paved and Unpaved Roads (Fugitive PM_{10} Prohibitions): Requires application of specific measures to minimize fugitive dust emissions from constructed paved and unpaved roads on the project site.

Rule 8071 – Unpaved Vehicle/Equipment Traffic Areas (Fugitive PM_{10} Prohibitions): Requires application of specific measures to minimize fugitive dust emissions from unpaved vehicle/equipment traffic areas experiencing more than 50 annual average daily trips.

5.1.7 Conformance of Facility

As addressed in this section, LEC is designed, and will be constructed and operated, in accordance with all relevant federal, state, and local requirements and policies concerning protection of air quality.

5.1.7.1 Consistency with Federal Requirements

The SJVAPCD has been delegated authority by the EPA to implement and enforce most federal requirements that may be applicable to the proposed project, including the new source performance standards and the Title IV and Title V Acid Rain and Operating Permit programs. Compliance with SJVAPCD regulations ensures compliance and consistency with the corresponding federal requirements as well. LEC will obtain an amended District Title V permit that includes applicable requirements for the modified power plant and includes Title IV Acid Rain provisions for the new unit.

EPA has retained the authority to issue PSD permits for sources in the SJVAPCD.

5.1.7.1.1 Federal Prevention of Significant Deterioration Program

EPA has promulgated PSD regulations for areas that are in compliance with national ambient air quality standards (40 CFR 52.21). The PSD program allows new sources of air pollution to be constructed, or existing sources to be modified, while preserving the existing ambient air quality levels, protecting public health and welfare, and protecting Class I areas (e.g., specific national parks and wilderness areas).

The five principal areas of the federal PSD program are as follows:

- Applicability
- Best available control technology
- Pre-construction monitoring
- Increments analysis
- Air quality impact analysis

Each of these elements of the program is discussed individually below.

Applicability

The PSD program was established to allow emission increases (increments of consumption) that do not result in significant deterioration of ambient air quality in areas where criteria pollutants have not exceeded NAAQS. The federal PSD requirements apply on a pollutant-specific basis to any project that is a new major stationary source or a major modification to an existing stationary source.[29] In the SJVAPCD, PSD requirements may be applicable for NO_x, SO_2~~, and~~ CO, and PM_{10} since the SJVAPCD is an attainment area for these pollutants[30]. PSD requirements do not apply for VOC or $PM_{2.5\cancel{10}}$, since the SJVAPCD is a nonattainment area for ozone and $PM_{2.5\cancel{10}}$. The determination of applicability is based on evaluating the NO_x, SO_2~~, and~~ CO, and PM_{10} emissions changes associated with the proposed project in addition to all other emissions changes at the same location since the applicable PSD baseline dates (40 CFR 52.21).

For the purposes of determining applicability of the PSD program requirements, the following regulatory procedure is used:

Emissions from the existing NCPA Lodi facility are compared with major source thresholds to determine whether the existing facility is a major source. This comparison is made in Table 5.1-34R.

Maximum potential emissions from the LEC are compared with regulatory significance thresholds to determine whether the modification itself is major and thus may be subject to

[29] These terms are defined in federal regulations at 40 CFR 52.21.

[30] The SJVAPCD was redesignated as an attainment area for PM_{10} following the submittal of the AFC. As a result of the redesignation, PM_{10} emissions from the project are now evaluated in this revised PSD applicability determination.

PSD. If the facility emissions exceed these thresholds, the proposed modification is subject to PSD review. The comparison in Table 5.1-35R indicates that the CO emissions from LEC exceed the major source threshold for the applicable source category,[31] and thus the project is subject to PSD review.

Contemporaneous emissions increases and decreases at the facility are included in the netting calculation to determine the net emissions changes at the facility. The net emissions changes are compared with the PSD significance levels in Table 5.1-36R.

If an ambient impact analysis is required, the analysis is first used to determine if the impact levels are significant. The determination of significance is based on whether the impacts exceed regulatory significance levels (40 CFR 51.165) shown in Table 5.1-37R.

TABLE 5.1-34R
STIG Plant Emissions and PSD Major Source Thresholds

Pollutant	NCPA Lodi CT#2 Emissions (tpy)	PSD Major Source Thresholds (tpy)	Major?
NO_x	20.4	100	No
SO_2	5.7	100	No
CO	58.8	100	No
PM_{10}	8.8	100	No

TABLE 5.1-35R
LEC Proposed Emissions and PSD Major Source Thresholds

Pollutant	LEC Emissions (tpy)*	PSD Major Source Thresholds (tpy)	Major?
NO_x	76.3 ~~71.5~~	100	No
SO_2	26.9 ~~24.3~~	100	No
CO	261.0 ~~254.9~~	100	Yes
PM_{10}	44.1	100	No

Note: LEC emissions include CTG/HRSG, auxiliary boiler and cooling tower.

[31] The determination that a combined-cycle gas turbine system is considered a “electric utility steam generating unit” for purposes of determining applicability of PSD requirements was made in an August 6, 2001, letter from John Seitz, Director Office of Air Quality Planning and Standards, EPA, to Patrick M. Raher of Hogan & Hartson L.L.P (accessed at www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/cgtsd.pdf.

TABLE 5.1-36R
Net Emission Increases and Significant Emissions Levels

Pollutant	Facility Net Increase (tpy)	PSD Significance Levels (tpy)	Are Increases Significant?
NO_x	76.3 ~~71.5~~	40	Yes
SO_2	26.9 ~~24.3~~	40	No
CO	261.0 ~~254.9~~	100	Yes
PM_{10}	44.1	15	Yes

TABLE 5.1-37R
PSD Significant Impact Levels (SILs) and Class II Increments

Pollutant	Averaging Time	SILs[a]	Maximum Allowable Class II Increments[b]
NO_2	Annual	1.0 µg/m^3	25 µg/m^3
CO	1-hour	2000 µg/m^3	n/a[c]
	8-hour	500 µg/m^3	n/a
PM_{10}	24-hour	5 µg/m^3	30
	Annual	1.0 µg/m^3	17

[a]40 CFR 51.165

[b]40 CFR 52.21

[c]No increments have been established for CO.

Table 5.1-34R shows that the existing NCPA Lodi turbine plant is not a major source under the PSD regulations. Table 5.1-35R shows that CO emissions from LEC will exceed the 100 ton major source threshold, so the project will be a major modification and thus subject to PSD review. Table 5.1-36R above shows that the NO_x and PM_{10} emissions from the project will above the PSD significance thresholds while the SO_x emissions will be below the threshold, so the project is subject to PSD review for NO_x, ~~and~~ CO, and PM_{10}.

If the significant impact levels (SILs) are exceeded, an analysis is required to demonstrate that the allowable increments will not be exceeded, on a pollutant-specific basis. Increments are the maximum increases in concentration that are allowed to occur above the baseline concentration. These PSD increments are also shown in Table 5.1-37R. There are no increments for CO.

Best Available Control Technology

BACT is defined in 40 CFR 52.21(j) as:

"an emissions limitation…based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant…"

A top-down BACT analysis is required for each pollutant subject to PSD review: that is, NO_x, ~~and~~ CO, and PM_{10}. The required top-down BACT analysis is provided in Appendix 5.1C, and concludes that BACT for the proposed project is as shown in Table 5.1-38R.

TABLE 5.1-38R
BACT Required Under Federal PSD for LEC

Pollutant	Controlled Emission Rate	Control Technique
NO_x	2.0 ppmvd @ 15% O_2	Dry low-NO_x combustion with selective catalytic reduction
CO	3.0 ppmvd @ 15% O_2	Oxidation catalyst
PM_{10}	9 lb/hr	Natural gas fuel

Preconstruction Monitoring

To ensure that the impacts from the LEC will not cause or contribute to a violation of an ambient air quality standard or an exceedance of a PSD increment, an analysis of the existing air quality in the project area is necessary. If a source is subject to PSD review, PSD regulations generally require preconstruction ambient air quality monitoring data for the purposes of establishing background pollutant concentrations in the impact area (40 CFR 52.21(m)). However, a facility may be exempted from this requirement if the predicted air quality impacts of the facility do not exceed the de minimis levels. Modeled impacts from the LEC are compared with the de minimis levels in Table 5.1-39R. Since modeled impacts are below the de minimis levels, the project may be exempted from the requirement.

TABLE 5.1-39R
PSD Preconstruction Monitoring Exemption Levels

Pollutant	Averaging Period	Maximum Modeled Concentration	De minimis Level	Exceed Monitoring Threshold?
NO_2	annual	0.64~~0.26~~ µg/m³	14 µg/m³	No
CO	8-hour average	110~~111~~ µg/m³	575 µg/m³	No
PM_{10}	24-hour average	3.7 µg/m³	10 µg/m³	No

The purpose of the preconstruction monitoring requirement is to verify that background concentrations are adequately characterized to ensure that the national ambient air quality standards are protected. With EPA's approval, a facility may rely on air quality monitoring data collected at District monitoring stations to satisfy the requirement for preconstruction monitoring. In such a case, in accordance with Section 2.4 of the EPA PSD guideline, the last 3 years of ambient monitoring data may be used if they are representative of the area's air quality where the maximum impacts occur due to the proposed source.

The background data need not be collected on site, as long as the data are representative of the air quality in the subject area (40 CFR 51, Appendix W, Section 9.2). Three criteria are applied in determining whether the background data are representative: (1) location, (2) data quality, and (3) data currentness.[32] These criteria are defined as follows:

Location: The measured data must be representative of the areas where the maximum concentration occurs for the proposed stationary source, existing sources, and a combination of the proposed and existing sources.

Data quality: Data must be collected and equipment must be operated in accordance with the requirements of 40 CFR Part 58, Appendices A and B, and PSD monitoring guidance.

Currentness: The data are current if they have been collected within the preceding 3 years and they are representative of existing conditions.

All of the data used in this analysis meet the requirements of Appendices A and B of 40 CFR Part 58, and thus all meet the criterion for data quality. All of the data have been collected within the preceding 3 years, and thus all meet the criterion for currentness. The location and overall representativeness of the data are discussed further below.

Data from the Hazelton Avenue monitoring station in Stockton, about 12 miles from the project site, were used to characterize CO, PM_{10} and NO_2 air quality at the project site. This station was chosen because of its proximity to the site and because data recorded there represent area-wide ambient conditions rather than the localized impacts of any particular facility. Because of the proximity of the monitoring station to the project, the data measured there are believed to be representative of the areas where the maximum project impacts will occur. Further, since ambient CO concentrations are generally driven by motor vehicle emissions and tend to be localized, the use of CO background data collected at Hazelton Avenue, which is in central Stockton near the Interstate 99 freeway, is expected to overpredict CO concentrations in the areas where the proposed project would have significant impacts.

PSD Increment Consumption

The maximum modeled impacts from the LEC facility are compared with the NO_2, ~~and~~ CO, and PM_{10} significant impact levels in Table 5.1-40R. These comparisons show that the maximum modeled ~~NO_2 and CO~~ impacts from the proposed project do not exceed the SILs. Therefore, no increments analysis is required for the proposed project.

TABLE 5.1-40R
PSD Significant Impact Levels (SILs) and Class II Increments

Pollutant	Averaging Time	Maximum Modeled Concentration	SILsa	Exceeds SIL?
NO_2	Annual	0.6~~0.3~~ μg/m³	1.0 μg/m³	No
CO	1-hour	337~~324~~ μg/m³	2000 μg/m³	No
	8-hour	110~~111~~ μg/m³	500 μg/m³	No
PM_{10}	24-hour	3.7 μg/m³	5 μg/m³	No
	Annual	0.6 μg/m³	1.0 μg/m³	No

[32] Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), EPA, 1987.

Air Quality Impacts Analysis

Because the maximum modeled NO_2, ~~and~~ CO, and PM_{10} impacts from the project are below the significance thresholds, no additional assessment of the impacts on ambient air quality are required under the PSD program requirements. However, a complete ambient air quality impacts analysis for NO_2, ~~and~~ CO, and PM_{10} was provided in Section 5.1.5 above. The AQIA demonstrated that the project will not cause or contribute to any violations of federal standards for which PSD review applies.

Impacts on Growth, Soils, Vegetation, and Sensitive Species

PSD requirements include an assessment of the secondary impacts from projects subject to review. These potential secondary impacts include growth, soils and vegetation, and sensitive species.

Growth

There will be minimal growth associated with the proposed project during the construction phase, due to the relatively short 24-month construction schedule and the broad regional availability of construction labor in the southern Sacramento and northern San Joaquin Valleys. Further, no direct project-related long-term growth is expected to occur in the area because only 21 additional permanent employees will be added as a result of the new plant.

The proposed project will not induce growth as a result of the additional power available. NCPA provides power to member agencies in northern California and is not a local power provider. The project is being developed by LEC in response to the growth in demand in the northern part of the state and will be available to back up non-fossil supplies such as hydro, solar and wind generating resources.

Vegetation, Soils and Sensitive Species

The LEC will be located in an area that is primarily agricultural. Criteria for evaluating impacts on soils and vegetation are provided by EPA guidance.[33] This document includes minimum impact levels for effects on sensitive vegetation and crops. Modeled project impacts are compared with these impact levels in Table 5.1-41R to demonstrate that no adverse impacts on vegetation are expected as a result of the project.

[33] Smith, A. E., and J. B. Levenson. *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals*. Research Triangle Park, N.C.: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, 1980.

TABLE 5.1-41R
Project Impacts to Vegetation and Sensitive Species

Pollutant	Averaging Period	Modeled Project Impacts (µg/m^3)	Ambient Background (µg/m^3)	Total (µg/m^3)	Minimum Ambient Concentration for Effects on Sensitive Plants (µg/m^3)
NO_2	4 hours[a]	28.5 ~~10.1~~	163.6	192.1 ~~178~~	3,760
	8 hours[a]	28.5 ~~10.1~~	163.6	192.1 ~~178~~	3,760
	1 month[a]	28.5 ~~10.1~~	163.6	192.1 ~~178~~	564
	Annual	0.6 ~~0.3~~	34.0	34.6 ~~34.3~~	94
SO_2	1 hour	3.8 ~~10.4~~	46.8	50.6 ~~57.2~~	917
	3 hours	2.4 ~~7.6~~	28.6	31.0 ~~36.2~~	786
	Annual	0.2 ~~0.1~~	2.7	2.9 ~~2.8~~	18
CO	1 week[b]	110 ~~111~~	3,178	3,280 ~~3,289~~	1,800,000

[a]Maximum modeled 1-hour average NO_2 concentrations used to conservatively represent impacts for averaging periods up to one month.

[b]Maximum modeled 8-hour average CO concentration used to conservatively represent 1-week average impact.

Project impacts on agriculture and soils are discussed in detail in Section 5.11 of the AFC. Project impacts on fauna are discussed under Biological Resources, Section 5.2 of the AFC.

Class I Area Impact Analysis and Class II PSD Significance Thresholds

In general, projects located within 100 km of Class I areas are required to evaluate impacts to visibility and other air quality-related values at those Class I areas as part of a PSD permit evaluation. The nearest Class I areas and their distances from the project are listed below.

Mokelumne Wilderness	106 km
Emigrant Wilderness	120 km
Desolation Wilderness	122 km
Yosemite National Park	124 km
Point Reyes National Seashore	127 km
Pinnacles Wilderness	180 km

Since all of these areas are more than 100 km from the project site, visibility and AQRV analyses should not be required. However, since the Mokelumne Wilderness is only slightly more than 100 km away, an assessment could otherwise be required for that area. The Federal Land Managers (FLMs) have developed a screening methodology for determining whether a proposed project is likely to have a significant impact on a Class I area when located within, or near to, the 100 km threshold. Under this procedure, the estimated sum of maximum NO_x, SO_x, and PM_{10} emissions (in tons per year) from the project is divided by the distance of each Class I areas from the project (in km) (National Park Service, 2007). The sum of the NO_x, SO_2, and PM_{10} emissions from the project is 147.3~~139.8~~ tons.[34] Using the distance

34 76.3~~71.5~~ tons (NOx) plus 26.9~~24.3~~ tons (SO_2) plus 44.1~~44.0~~ tons (PM_{10}).

to the closest Class I area, 106 km, the quotient is 1.39~~1.32~~. Because this quotient is substantially less than the FLM threshold level of 10, it is expected that even if the project is subject to PSD review it will not be required by the FLMs to evaluate impacts to visibility and other air quality related values at Class I areas.

5.1.7.1.2 Federal New Source Performance Standards

The Standards of Performance for New Stationary Sources are source-specific federal regulations, limiting the allowable emissions of criteria pollutants (i.e., those that have a national ambient air quality standard). These regulations apply to certain sources depending on the equipment size, process rate, and/or the date of construction, modification, or reconstruction of the affected facility. Recordkeeping, reporting, and monitoring requirements are usually necessary for the regulated pollutants from each subject source; the reports must be regularly submitted to the reviewing agency (40 CFR 60.4). This program has been delegated by EPA to the SJVAPCD.

Subpart KKKK, the NSPS for Stationary Gas Turbines, and Subpart Dc, the NSPS for small Commercial-Institutional-Industrial Boilers, are applicable to the equipment proposed for this project. Subpart KKKK limits NO_x and SO_2 emissions from new gas turbines ~~based on power output~~. The applicable emissions limits for ~~gas turbines greater than 30 MW~~ the proposed project are 15 ppm NOx @ 15%O_2 (or 0.43~~0.39~~ lb NO_x per MW-hr) and 0.90~~0.58~~ lb SO_2 per MW-hr. The emission limits of 2.0 ppmc NO_x and 0.56 ppmc SO_2 proposed for the LEC turbine ~~and duct burners~~ are well below the Subpart KKKK limits, as shown in Table 5.1-42R.

TABLE 5.1-42R
Compliance With 40 CFR 60 Subpart KKKK

Pollutant	Proposed Permit Limits			Subpart KKKK Limit, lb/MW-hr
	ppmc	lb/hr	lb/MW-hr (max)	
NO_x	2.0	15.5 ~~15.25~~	0.05	0.43 ~~0.39~~
SO_2	0.57	6.1 ~~6.0~~	0.02	0.90 ~~0.58~~

Compliance with the NSPS limits must be demonstrated through an initial performance test. Because the LEC gas turbine/HRSG will be equipped with a continuous NO_x emissions monitor, ongoing annual performance testing will not be required under the NSPS.

Subpart Dc limits SO_2 and PM_{10} emissions from new small boilers. Because the LEC auxiliary boiler will burn only natural gas, its permitted emissions will be well below any applicable limits in Subpart Dc.

5.1.7.1.3 National Emissions Standards for Hazardous Air Pollutants

The NESHAPs are either source-specific or pollutant-specific regulations, limiting the allowable emissions of hazardous air pollutants from the affected sources (40 CFR Part 63). Unlike criteria air pollutants, hazardous air pollutants do not have a national ambient air quality standard but have been identified by EPA as causing or contributing to the adverse health effects of air pollution.

NESHAPs are applicable only to major sources of HAPs. The assessment of noncriteria pollutant emissions from the facility in Section 5.1.3.6 included a calculation of total HAP emissions from the new and existing facilities after modification. Since HAP emissions do not exceed 10 tpy for any individual HAP or 25 tpy in total, the project is not a major source of HAPs. Therefore, LEC is not subject to any NESHAP requirements.

5.1.7.1.4 Federal Clean Air Act Amendments of 1990

In November 1990, substantial revisions and updates to the federal Clean Air Act were signed into law. This complex enactment addresses a number of areas that could be relevant to the proposed LEC, such as more extensive permitting requirements and new EPA mandates and deadlines for developing rules to control air toxic emissions. The most significant of the new provisions applicable to this project are the Title IV acid rain and Title V operating permit programs.

Title IV—Acid Rain

As a Phase II Acid Rain facility, the LEC will be required to provide sufficient allowances for every ton of SO_2 emitted during a calendar year. LEC will also be required to install and operate a NO_x CEMS that complies with program requirements. SJVAPCD has been delegated the authority to implement the acid rain permitting program. Compliance with program requirements is discussed below with other local district requirements.

Title V—Operating Permits

This title establishes a comprehensive operating permit program for major stationary sources (42 USC §7661 et seq.). Under the Title V program, a single permit is required that includes a listing of all the stationary sources, applicable regulations, requirements, and compliance determinations.

SJVAPCD's Title V Program (Rule 2520) has been approved by EPA. Consequently, SJVAPCD has received delegation to implement the Title V program. SJVAPCD Title V permit programs applicable to this project are summarized below.

5.1.7.2 Consistency with State Requirements

State law sets up local air pollution control districts and air quality management districts with the principal responsibility for regulating emissions from stationary sources. As discussed above, the project is under the local jurisdiction of the SJVAPCD, and compliance with SJVAPCD regulations will assure compliance with state air quality requirements.

5.1.7.2.1 California Clean Air Act

AB 2595, the California Clean Air Act (CAA) was enacted by the California Legislature and became law in January 1989. The CAA requires the local air pollution control districts to attain and maintain both the federal and state ambient air quality standards at the "earliest practicable date." The CAA contains several milestones for local districts and the CARB. SJVAPCD was required to submit to the CARB an air quality plan, with updates as necessary, defining the program for meeting the required emission reduction milestones in the San Joaquin Valley.

Air quality plans must demonstrate attainment of the state ambient air quality standards and must result in a five percent annual reduction in emissions of nonattainment pollutants (ozone, PM_{10}, $PM_{2.5}$, and associated precursors) in a given district (H&SC §40914). A local district may adopt additional stationary source control measures or transportation control measures, revise existing source-specific or new source review rules, or expand its vehicle inspection and maintenance program (H&SC §40918) as part of the plan. District air quality plans specify the development and adoption of more stringent regulations to achieve the requirements of the Act. The applicable regulations that will apply to LEC are included in the discussion of District prohibitory rules in Section 5.1.7.3.

5.1.7.2.2 Greenhouse Gas Initiatives

In 2006, California enacted the California Global Warming Solutions Act of 2006 (AB 32). It requires the California Air Resources Board (CARB) to adopt standards that will reduce statewide GHG emissions to statewide GHG emissions levels in 1990, with such reductions to be achieved by 2020. To achieve this, CARB has a mandate to define the 1990 emissions level and achieve the maximum technologically feasible and cost-effective GHG emission reductions.

The CARB adopted early action GHG reduction measures in October 2007 and will establish statewide emissions caps by economic "sectors" in 2008. By January 1, 2009, CARB will adopt a scoping plan that will identify how emission reductions will be achieved from significant sources of GHG via regulations, market mechanisms, and other actions. CARB staff will then draft regulatory language to implement its plan and will hold additional public workshops on each measure, including market mechanisms.

SB 1368, also enacted in 2006, and regulations adopted by the CEC and the Public Utilities Commission pursuant to the bill, prohibits utilities from entering into long-term commitments with any baseload facilities that exceed the Emission Performance Standard of 0.500 metric tones of CO_2 per megawatt-hour (1,100 pounds CO_2/MWh). Specifically, the Emission Performance Standard (EPS) applies to base load power from new power plants, new investments in existing power plants, and new or renewed contracts with terms of five years or more, including contracts with power plants located outside of California. If a project, in-state or out of state, plans to sell base load electricity to California utilities, the utilities will have to demonstrate that the project complies with the EPS.

Since the project is permitted for more than 60 percent annual capacity factor, it must emit less than 0.500 mt CO_2/MWh to meet the EPS. The project is expected to emit ~~0.365~~0.357 mt CO_2/MWh, (CO_2, not CO_2-equivalent), as shown in Table 5.1-22R above. Therefore, the facility will comply with the EPS. As the CEC's 2007 Integrated Energy Policy Report[35] noted:

"New natural gas-fueled electricity generation technologies offer efficiency, environmental, and other benefits to California, specifically by reducing the amount of natural gas used—and with less natural gas burned, fewer greenhouse gas emissions. Older combustion and steam turbines use outdated technology that makes them less fuel- and cost-efficient than newer, cleaner plants… The 2003 and 2005 IEPRs noted that the state could help reduce natural gas consumption for electric generation by taking steps to retire older, less efficient natural gas power plants and replace or repower them with new, more efficient power plants." (p. 184)

[35] CEC-100-2007-008-CMF, December 5, 2007, accessed at http://www.energy.ca.gov/2007_energypolicy/

Thus, in both the context of the California Environmental Quality Act and CEC's Integrated Energy Policy Report, the proposed project would not be expected to cause a significant cumulative impact and furthers the state's strategy to reduce fuel use and GHG emissions. Further, even though it is possible to quantify how many gross GHG emissions are attributable to a project, it is difficult to determine whether this will result in a net increase of these emissions, and, if so, by how much. Therefore, it would be speculative to conclude that any given project results in a cumulatively significant adverse impact resulting from greenhouse gas emissions.

At this time, neither the state nor the APCD has adopted thresholds of significance or methodologies for analyzing GHG emission impacts under CEQA. The State Office of Planning and Research has recently begun the process of drafting proposed guidelines for analyzing GHG emissions, but these guidelines are not expected to be adopted until January 2010. Additionally, CARB is currently in the process of drafting a scoping plan to achieve the emission reduction targets of AB 32. In the interim period while the AB 32 and CEQA GHG-related regulatory programs are being developed, projects may be judged on whether they will hinder the emission reduction goals of AB 32.

The CEC has issued several decisions concerning projects subject to its decision since passage of AB 32. Recently, the Final Commission Decision on the 660 MW Colusa Generating Station (CGS) discussed the schedule by which the CARB will develop regulations to manage GHG emissions and imposed a condition of certification AQ-SC8 that "…requires the project owner to report the quantities of relevant greenhouse gases emitted as a result of electric power production." More important was the following finding: "We find that AQ-SC8, with the reporting of GHG emissions, will enable the project to be consistent with the regulations and policies described above" (referring to AB 32 and Senate Bill 1368 (Electricity Greenhouse Gas Emissions Standards)). As a routine matter, the CEC includes such reporting in its decisions. Such GHG emission reporting is already carried out on a regular basis by NCPA in its annual reports to the California Climate Action Registry under the specific requirements of the Power/Utility Reporting Protocol (April 2005) for each of its generating units.

In the absence of established thresholds of significance or methodologies for assessing impacts, this analysis of GHG emission impacts consists of quantifying project-related GHG emissions, determining their significance in comparison to the goals of AB 32, and discussing the potential impacts of climate change within the state as well as strategies for minimizing those impacts.

5.1.7.3 Consistency with Local Requirements: SJVAPCD

The SJVAPCD has been delegated responsibility for implementing local, state, and federal air quality regulations in the eight counties[36] within the SJVAPCD. The project is subject to SJVAPCD regulations that apply to new sources of emissions, to the prohibitory regulations that specify emission standards for individual equipment categories, and to the requirements for evaluation of impacts from toxic air pollutants. The following sections include the evaluation of facility compliance with the applicable SJVAPCD requirements.

36 Including the portion of Kern County that is within the SJVAPCD boundaries.

Under the regulations that govern new sources of emissions, the project is required to secure a preconstruction Determination of Compliance from the SJVAPCD (Rule 2201), as well as demonstrate continued compliance with regulatory limits when the project becomes operational. The preconstruction review includes demonstrating that the project will use BACT and will provide any necessary emission offsets.

Applicable BACT thresholds are shown in Table 5.1-43R, along with anticipated potential emissions from each unit and criteria pollutant. SJVAPCD Rule 2201 requires BACT for each unit emitting CO, NO_x, VOC, SO_x, or PM_{10} (criteria pollutants) in excess of 2.0 pounds per highest day (with facility-wide CO emissions in excess of 200,000 pounds per year). The calculation of facility emissions was discussed in Section 5.1.3.

TABLE 5.1-43R
Best Available Control Technology Requirements

Pollutant	BACT Applicability Threshold (lbs/day)	Turbine/HRSG Maximum Emissions (lbs/day)	Turbine/HRSG BACT Required?	Auxiliary Boiler Maximum Emissions (lbs/day)	Auxiliary Boiler BACT Required?
NO_x	2	879.7 ~~864.9~~	yes	7.4 ~~6.5~~	yes
VOC	2	164.3 ~~179.8~~	yes	3.7 ~~3.3~~	yes
SO_2	2	146.4 ~~136.4~~	yes	2.5 ~~2.2~~	yes
PM_{10}	2	216.0 ~~240.0~~	yes	6.7 ~~5.6~~	yes
CO*	2	5,655.4 ~~5,641.9~~	yes	32.1 ~~28.5~~	yes

*Facility-wide CO emissions exceed 200,000 lb/year, therefore BACT threshold of 2 lb/day applies to all new equipment.

As shown in Table 5.1-43R, BACT is required as follows:

- Turbine/HRSG: NO_x, VOC, SO_2, CO, and PM_{10}
- Auxiliary boiler: NO_x, VOC, SO_2, CO, and PM_{10}.

In addition, since the cooling tower daily emissions of 22.3~~10.8~~ lb/day exceed the 2 lb/day BACT threshold, BACT is also required for PM_{10} emissions from the cooling tower.

BACT for the applicable pollutants was determined by reviewing the SJVAPCD BACT Clearinghouse,[37] the South Coast Air Quality Management District (SCAQMD) BACT Guidelines,[38] the CARB BACT Determinations,[39] and EPA's Reasonably Available Control Technology (RACT)/BACT/LAER Clearinghouse (RBLC).[40] A summary of the review is provided in Appendix 5.1C.

NO_x BACT – BACT for NO_x emissions from the gas turbine will be the use of low NO_x emitting equipment and add-on controls. The Applicant has selected a gas turbine equipped with dry low-NO_x combustors. The gas turbines will generate approximately 9 ppmvd NO_x,

37 SJVAPCD. BACT Clearinghouse, http://www.valleyair.org/busind/pto/bact/bactchidx.htm.
38 SCAQMD. BACT Guidelines, http://www.aqmd.gov/bact/BACTGuidelines.htm.
39 CARB. Statewide BACT, http://www.arb.ca.gov/bact/bact.htm.
40 EPA. RBLC, http://cfpub.epa.gov/rblc/htm/bl02.cfm.

corrected to 15 percent O_2, at the entry to the HRSGs. In addition, the turbines will be equipped with an SCR system to further reduce NO_x emissions to 2.0 ppmvd NO_x, corrected to 15 percent O_2. Hourly average NO_x emissions will not exceed 2.0 ppmvd @ 15% O_2 (excluding startups and shutdowns). ~~The duct burner will also be exhausted to the SCR system; therefore, BACT for the duct burner is the same 2.0 ppmvd NO_x level, corrected to 15 percent O_2.~~ A review of recent BACT determinations for NO_x from gas turbines is shown in Appendix 5.1C.

BACT for NO_x emissions from the auxiliary boiler will be the use of low NO_x emitting equipment. The project has selected a boiler equipped with ultra low-NO_x burners. The boiler with low NO_x burners will generate less than 7 ppmvd NO_x, corrected to 3 percent O_2. The SJVAPCD BACT guidelines indicated that BACT from a boiler (> 20 MMBtu/hr heat input) with highly variable loads or high turndown ratios is a NO_x exhaust concentration not to exceed 15 ppmvd, corrected to 3 percent O_2; therefore, the project will meet or exceed the BACT requirements for NO_x. A review of recent BACT determinations for NO_x from boilers is shown in Appendix 5.1C.

CO BACT – BACT for CO emissions will be achieved by use of a gas turbine equipped with a dry low-NO_x combustor and an oxidation catalyst. Dry low-NO_x combustors emit low levels of combustion CO while still maintaining low- NO_x formation. In addition, the project will use an oxidation catalyst system to further reduce CO emissions to 3.0 ppmvd, corrected to 15 percent O_2 (excluding startup and shutdown periods). SJVAPCD BACT Guideline 3.4.2 C indicates that BACT from a large gas turbine with heat recovery is 4.0 ppmvd CO, corrected to 15 percent O_2. CO emissions from the proposed gas turbines will meet this BACT requirement. A review of recent BACT determinations for CO from gas turbines is provided in Appendix 5.1C.

The auxiliary boiler will achieve a CO emission rate of 50 ppmvd, corrected to 3 percent O_2. While the SJVAPCD BACT guidelines do not include a specific BACT level for CO, guidelines in other districts (e.g., SCAQMD, BAAQMD) indicate that BACT for boilers is 50 ppmvd at 3 percent O_2. The proposed CO emission rate is consistent with these BACT determinations.

VOC BACT – BACT for VOC emissions will be achieved by use of the gas turbine dry low-NO_x combustor. As in the case of CO emission formation, dry low- NO_x combustors that result in low combustion VOC while still maintaining low NO_x levels. BACT for VOC emissions from combustion devices has historically been the use of best combustion practices. With the use of the dry low- NO_x combustors ~~and with the duct burner emission level, VOC emissions will be limited to 2.0 ppmvd, corrected to 15 percent oxygen. Without duct firing~~, VOC emissions will be limited to 1.4 ppmvd, corrected to 15 percent oxygen. This level of emissions is consistent with the SJVAPCD's BACT guidelines for large gas turbines.

BACT for VOC emissions for the auxiliary boiler will be achieved by the use of natural gas fuel and good combustion practices. The VOC emissions will be 10.0 ppmvd, corrected to 3 percent O_2. SJVAPCD BACT Guideline 1.1.3 indicates that VOC BACT for boilers greater than 20 MMBtu/hr is natural gas fuel and good combustion practices. The low NO_x burners are designed to minimize incomplete combustion and therefore minimize VOC emissions.

PM_{10} BACT – For the turbine~~, duct burner~~ and auxiliary boiler, BACT for PM_{10} is good combustion practices and the use of natural gas fuel, which will result in minimal particulate emissions. The turbine and HRSG will also utilize an air inlet filter and lube oil vent coalescer to minimize PM_{10} emissions.

For the cooling tower, drift eliminators will be used to keep the drift rate below 0.0005%. This is the drift rate commonly achieved by cooling towers of this type and in combination with the proposed 5400~~3000~~ ppm limit on TDS in the cooling tower water, will minimize PM_{10} emissions from the cooling tower.

SO_2 BACT – SO_2 emissions will be kept at a minimum by firing clean burning natural gas fuel with a maximum sulfur content of 1.0 gr/100 scf.

In addition to the BACT requirements, SJVAPCD Rule 2201 requires the project to provide emission offsets when emissions exceed specified levels on a pollutant-specific basis. Offsets for CO are not required because the air quality impact analysis is expected to demonstrate to the satisfaction of the APCO that the ambient air quality standards for CO are not currently being violated and that the project would not cause or contribute to a violation of the standards (see Table 5.1-29R). As shown in Table 5.1-44R, the project must provide emission offsets for NO_x, PM_{10}, SO_2, and VOC emissions.

TABLE 5.1-44R
SJVAPCD Offset Requirements and Project Emissions

Pollutant	Emissions from Existing Facility, tpy	Emissions from New Facility, tpy	District Offset Threshold, tpy	Offsets Required
VOC	25.9	16.8~~17.5~~	10.0	Yes
NO_x	20.4	76.3~~71.5~~	10.0	Yes
SO_2	5.7	26.9~~24.3~~	27.4	Yes
PM_{10}	8.8	44.1~~44.0~~	14.6	Yes

The NSR rule requires emission reductions to be provided at an offset ratio of between 1 and 1.5 to 1, depending upon the distance between the source and the offset location. Interpollutant offsets are permitted, at the discretion of the APCO. Appendix 5.1F presents a demonstration of compliance with the offset and mitigation requirements for the proposed project. The demonstration includes a listing of credits owned by the Applicant, a quarterly reconciliation of offset requirements and ERCs, and an analysis of interpollutant offset ratios to be used to fulfill the PM_{10} offset and mitigation requirements for the project.

The NSR rule also only allows project approval if air quality modeling results indicate emissions will not cause or exacerbate the violation of the applicable ambient air quality standards, after accounting for mitigation. The modeling analyses in Section 5.1.5 show that with the exception of PM_{10}, facility emissions will not interfere with the attainment or maintenance of the applicable air quality standards. Because the SJVAB is currently a nonattainment area for state PM_{10} and federal $PM_{2.5}$ ambient air quality standards, any increase in PM_{10} emissions has the potential to exacerbate existing violations. The Applicant will be providing PM_{10} offsets to mitigate the impact of the emissions increase; as a result, the required finding can be made for PM_{10} as well.

Rule 2520, Federal Part 70 Permits (Title V permit program) applies to major sources on a pollutant-specific basis. The Phase II acid rain requirements of Rule 2540 are also applicable to the facility. As a Phase II Acid Rain facility, the project will be required to provide sufficient allowances for every ton of SO_2 emitted during a calendar year. The applicant will file the appropriate applications for modifications to the existing Title V and acid rain permits, and will obtain any additional offsets, as needed, on the open trade market. The project will also install and operate the required continuous emissions monitoring systems (CEMS).

The general prohibitory rules of the SJVAPCD applicable to the project and the determination of compliance follow.

Rule 4001 (New Source Performance Standards). Subparts Dc and KKKK of this rule require monitoring of fuel; impose limits on the emissions of NO_x, PM, and SO_2; and require source testing of stack emissions, process monitoring, and data collection and recordkeeping. All of the BACT limits imposed on the facility will be more stringent than the requirements of the NSPS emission limits. Monitoring and recordkeeping requirements for BACT will be more stringent than the requirements in this rule; therefore, the project will comply with the NSPS regulations.

Rule 4101 (Visible Emissions). Any visible emissions from the project will not be darker than No. 2 when compared to a Ringlemann Chart for any period(s) aggregating 3 minutes in any hour. Because the facility will burn clean fuels, the opacity standard of not greater than 20 percent for a period or periods aggregating 3 minutes in any hour and the particulate emission concentrations limit of 0.15 grains per standard cubic feet of exhaust gas volume will not be exceeded.

Rule 4102 (Public Nuisance). The facility will not emit significant quantities of odorous or visible substances; therefore, the facility will comply with this regulation.

Rule 4201 (Particulate Matter Emission Standards). The emission units will have particulate matter emission rates well below the limits of the rule. The maximum grain loading for the turbines~~ and duct burners~~ (from Table 5.1A-1, Appendix 5.1A) is 0.002 gr/dscf, well below the 0.1 gr/dscf limit of the rule.

Rule 4320 (Advanced Emission Reduction Options For Boilers, Steam Generators, And Process Heaters Greater Than 5.0 MMBtu/hr). The auxiliary boiler will comply with the requirements of this proposed rule by limiting NO_x emissions to not more than 7 ppmc. The applicant will submit to the APCO for approval proposals for an Alternate Monitoring System for NO_x and CO emissions and a parametric monitoring system to track SO_x and PM_{10} emissions.

Rule 4703 (Stationary Gas Turbines). Emissions from the new turbine will be well below the limits in this rule. The applicant is requesting SJVAPCD's approval of startup times up to 6 hours as necessary. As discussed in the BACT analysis of startup emissions provided in Appendix 5.1C, startup emissions from the CTG will be minimized through the use of the Flex Plant~~Rapid Response~~ technology. However, because there is no operational experience with this technology, LEC cannot ensure that this new technology will allow the turbine to come into compliance with the Rule 4703 NO_x and CO limits within 2 hours. [41]

The 2-hour limit on the duration of a startup or shutdown in Section 5.3.1 of Rule 4703 is not sufficient for the proposed configuration of one Siemens SCC6-5000F turbine with unfired heat recovery steam generator (HRSG) and steam turbine. The proposed equipment will require up to approximately 6 hours to achieve compliance with Rule 4703, depending on the steam turbine temperature at the time the startup is initiated. A startup is defined as the period beginning with turbine initial firing and ending when the turbine exhaust meets the permitted NO_x and CO concentrations. The justification for these longer startup times complies with the rule requirements outlined below. Each section of rule language is followed by the required project-specific information.

Section 5.3.3.2.1 – A clear identification of the control technologies or strategies to be utilized [to minimize emissions]:

> The control technologies and strategies to be utilized to minimize emissions during the startup period are as follows:
>
> - "Flex Plant™ 30" technology, including an auxiliary boiler to preheat fuel and provide steam turbine sealing steam prior to CTG startup.
> - Dry low-NO_x combustors in the CTG.
> - Oxidation catalyst in the HRSG.
> - SCR in the HRSG.
> - Good combustion practices.
> - Upon startup, the ammonia injection upstream of the SCR catalyst will be started as soon as the catalyst and ammonia injection system warm to their minimum operating temperatures as specified by the SCR vendor.

Section 5.3.3.2.2 – A description of what physical conditions prevail during the period that prevent the controls from being effective:

> The combined-cycle equipment startup duration depends on how fast the high-pressure steam drum and the steel walls of the steam turbine can be warmed to operating temperature without generating stress cracks or otherwise damaging the equipment. During a cold startup, in which the CTG/HRSG have been shut down for more than 72 hours, the HRSG and steam turbine parts are at ambient temperature and there is a great deal of thermal mass that must be heated. Once the high-pressure steam drum is heated, steam developed in the HRSG from the heated turbine exhaust is admitted into the steam turbine at a controlled temperature to heat it as rapidly as possible without causing stress cracking. The steam temperature is controlled by limiting the load on the gas turbine. At the lower load points, the gas turbine is tuned for combustion stability and not for emissions performance, so uncontrolled

[41] At the request of the District, additional information was provided following submittal of the AFC to allow the District to approve the longer startup time requested by the applicant. For ease of review, this additional information is also being included in this supplement.

emissions at low loads are much higher than uncontrolled emissions at typical operating loads (above about 50%).

The allowable rate of temperature increase at the steam turbine is the limiting factor in determining how quickly the gas turbine can achieve higher loads. This, in turn, limits how quickly the gas turbine combustor can be brought up to this minimum load point, and this latter step is necessary for the unit to be able to comply with the emission limits of Rule 4703.

Section 5.3.3.2.3 – A reasonably precise estimate as to when the physical conditions will have reached a state that allows for the effective control of emissions:

Startup information provided by the turbine and HRSG vendors indicates that for a cold startup, a minimum of 4 hours is required for the unit to come into compliance with the limits of Rule 4703. Experience at other combined cycle gas turbine power plants has shown that up to 6 hours may be required under some circumstances. Because NCPA is proposing to use "Flex Plant TM 30" rapid start technology for this project, we expect that startups of the new LEC gas turbine will be shorter than those experienced for other projects. The Flex Plant package, which includes a modified HRSG design and an auxiliary boiler, is designed to allow faster heating of the HRSG and earlier startup of the steam turbine, significantly reducing startup times. However, because no Flex Plant configuration plants have yet been built or operated, no in-use operating data are yet available to allow observation and evaluation of the actual times required for a unit to come into compliance during a startup. Therefore, NCPA is conservatively assuming that the times required for startups of the LEC will be the same as those for conventional 5000F-based combined cycle turbine plants.

Section 5.3.3.2.4 – A detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity:

Specific activities may vary among different HRSG and steam turbine vendors. However, example activities that occur upon initiation of the startup sequence are listed below. Approximate times refer to requirements for a cold startup.

- Initiate gas turbine firing up to the low load hold point, which is determined by the metal temperature of the steam turbine at the HP steam and hot reheat inlets.
- Monitor temperature and water level in high pressure (HP), intermediate pressure (IP), and low pressure (LP) steam drums.
- Place the drum level controls in automatic mode after water level is at specified height.
- The gas turbine is held at the low-load point to control steam temperature throughout the following activities:
- Drain valves on the HRSG and piping connecting to the steam turbine (STG) open to vent steam while pressure builds in the HRSG steam drums and piping connecting to the STG.

- As the cold piping warms, steam is condensed. The condensate blows out through the open drain valves.
- Pressure in the steam piping and HRSG drums is controlled by bypassing the STG and dumping steam to the condenser provided that acceptable condenser vacuum has been established.
- The drain valves remain open until the steam piping is hot and condensation of the steam ceases. The steam must be dry prior to admission to the STG. This process takes approximately 1 hour depending upon ambient conditions and the temperature of the equipment at startup.
- Hot reheat steam is initially admitted only to the IP section of the STG, and the STG speed is held at approximately 3,000 rpm for 20 minutes while the STG is monitored for vibrations that can occur as the rotor slowly warms.
- If vibrations are within acceptable limits, the STG load may be increased to 10% over a period of approximately 10 minutes.
- STG load is held at 10% for approximately 30 minutes while the metal continues to warm.
- The HP steam inlet valves open and allow the STG load to increase to 15% to 25% over a period of approximately 10 minutes.
- STG load is held while the inlet valves open and establish pressure control at the HP steam inlet.

Section 5.3.3.2.5 – A description of the material process flow rates and system operating parameters, etc., the operator plans to evaluate during the process optimization; and an explanation of how the activities and process flow affect the operation of the emissions control equipment:

> The startup duration depends on the allowable ramp rate of the steam temperature to the steam turbine, which depends on the acceptable rate of increase of the metal temperature of the hot reheat and HP steam bowls at the steam turbine inlets. The maximum steam temperature is set by applying an allowable differential above the metal temperature. The differential is determined by the steam turbine supplier, and is imposed by the supplier's control system to avoid damage to the steam turbine from thermal stress. The control system limits gas turbine load to control the steam temperature. Any manual override of the gas turbine load limit by the operator reduces the life expectancy of the steam turbine.

In addition, the time prior to initiation of ammonia flow to the SCR system depends on the temperature of the SCR catalyst. The catalyst bed is warmed by the exhaust flow from the gas turbine. The total mass of metal and water in the HRSG tubes, piping, and drums removes heat from the gas turbine exhaust as it warms. This extends the time required to heat the SCR catalyst to the minimum temperature at which ammonia may be injected upstream of the catalyst bed to begin reducing NO_x to N_2. The steam turbine and SCR catalyst temperatures are all monitored by the plant control system, and the turbine ramp rate and SCR initiation sequence are governed by the equipment/system manufacturer's recommended procedures.

Section 5.3.3.2.6 – The basis for the requested additional duration:

> The description of activities above demonstrates that the minimum time required for a cold startup of the plant as currently configured is approximately 4 hours. This startup time is contingent upon all of the activities being performed in time to support subsequent activities. Any delay in preparation of the supporting systems will result in a corresponding delay in startup and/or loading of the gas turbine. To be confident that the startup time allowed is adequate and will not be exceeded, and based on experience at other facilities, 2 hours are added to the above minimum startup time to account for possible delays.

Because faster-starting "Flex Plant™ 30" technology is being proposed for this project, NCPA expects to be able to accomplish startups in much less time than the 6 hours requested as a permit limit. However, as discussed in the permit application, the lack of real-world operating experience for Flex-Plant quick start configuration plants requires NCPA to be conservative in its assumptions regarding plant performance to ensure that the project can be operated in compliance with all permit conditions at all times.

NCPA is proposing the following change to PDOC Condition 21, which would require reassessment of startup times after the first full year of operating experience with the new Flex Plant design:

21. Except as provided below, the ~~The~~ duration of ~~combined~~ any startup ~~and~~ or shutdown period shall not exceed six hours ~~in any one day~~ for any single event:

    a. The owner/operator shall maintain continuous emissions monitoring (CEM) data and complete records of plant NOx and CO emissions performance under startup conditions. The owner/operator shall record the minute-by-minute NOx and CO emissions concentrations and turbine load and the duration of each startup that occurs during the first 12 months of operation following the end of the commissioning period.

    b. Within 15 months of the end of the commissioning period, the owner/operator shall submit to the District and EPA proposed new time limits for cold, warm and hot gas turbine start-ups that reflect the effect of rapid start technology. The proposal shall be based on continuous emissions data for NOx and CO collected during gas turbine startup periods during the first 12 months of operation following the end of the commissioning period. The submittal shall include all CEMS data collected in accordance with (a) above. In no event shall the time limits imposed for each type of startup be less than sixty (60) minutes longer than the longest startup event of that type recorded during the first 12 months of operation following the end of the commissioning period.

Rule 4801 (Sulfur Compound Emissions). Because the project will use only natural gas fuel, all of the Rule 4801 limits will easily be complied with.

Rule 7012 (Hexavalent Chromium – Cooling Towers). The cooling tower will not use hexavalent chromium.

Rule 8011 (Fugitive PM_{10} Prohibitions, General Requirements). This rule includes definitions, exemptions, requirements and fees related to the control of fugitive PM_{10}.

Rule 8021 (Fugitive PM_{10} Prohibitions, Construction, Demolition, Excavation, Extraction and other Earthmoving Activities). This rule requires the use of specified control measures to control fugitive dust emissions during construction activities, and the submittal of a Dust Control Plan prior to the commencement of construction. NCPA has committed to use dust control measures during construction to minimize fugitive dust emissions.

A summary of LORS compliance is provided in Table 5.1-45 below.

TABLE 5.1-45
Laws, Ordinances, Regulations, Standards, and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	Conformance (Section; Page)
Federal					
Clean Air Act (CAA) §160-169A and implementing regulations, Title 42 United States Code (USC) §7470-7491 (42 USC 7470-7491), Title 40 Code of Federal Regulations (CFR) Parts 51 & 52 (40 CFR 51 & 52) (Prevention of Significant Deterioration Program)	Requires prevention of significant deterioration (PSD) review and facility permitting for construction of new or modified major stationary sources of air pollution. PSD review applies to pollutants for which ambient concentrations are lower than NAAQS.	EPA	Issues PSD permit with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.1.1; p. 5.1-59 et seq Appendix 5.1C
CAA §171-193, 42 USC §7501 et seq. (New Source Review)	Requires new source review (NSR) facility permitting for construction or modification of specified stationary sources. NSR applies to pollutants for which ambient concentration levels are higher than NAAQS.	SJVAPCD with EPA oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p. 5.1-70 et seq Appendix 5.1C
CAA §401 (Title IV), 42 USC §7651 (Acid Rain Program)	Requires reductions in NO_x and SO_2 emissions.	SJVAPCD with EPA oversight	Issues Acid Rain (FDOC/ATC) permit after review of application.	Application to be made within 12 months of start of facility operation; LEC not subject to this program.	§5.1.7.1.4; p. 5.1-67
CAA §501 (Title V), 42 USC §7661 (Federal Operating Permits Program)	Establishes comprehensive permit program for major stationary sources.	SJVAPCD with EPA oversight	Issues amended Title V permit after review of application.	Application for amendment to be made at least 12 months prior to start of facility operation.	§5.1.7.1.4; p. 5.1-67
CAA §111, 42 USC §7411, 40 CFR Part 60 (New Source Performance Standards [NSPS])	Establishes national standards of performance for new stationary sources.	SJVAPCD with EPA oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.1.2; p. 5.1-66
CAA §112, 42 USC §7412, 40 CFR Part 63 (National Emission Standards for Hazardous Air Pollutants [NESHAPs])	Establishes national emission standards for hazardous air pollutants.	SJVAPCD with EPA oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.1.3; p. 5.1-66

TABLE 5.1-45
Laws, Ordinances, Regulations, Standards, and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	Conformance (Section; Page)
State					
California Health & Safety Code (H&SC) §41700 (Nuisance Regulation)	Prohibits discharge of such quantities of air contaminants that cause injury, detriment, nuisance, or annoyance.	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p. 5.1-73
H&SC §44300-44384; California Code of Regulations (CCR) §93300-93347 (Toxic "Hot Spots" Act)	Requires preparation and biennial updating of facility emission inventory of hazardous substances; risk assessments.	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Screening HRA submitted before start of construction.	§5.1.7.2.2; p. 5.1-68 §5.9 (Public Health)
California Public Resources Code §25523(a); 20 CCR §1752, 2300-2309 (CEC & CARB Memorandum of Understanding)	Requires that CEC's decision on AFC include requirements to assure protection of environmental quality; AFC required to address air quality protection.	CEC	After project review, issues FDOC/ATC with conditions limiting emissions.	CEC approval of AFC, including all conditions contained in FDOC, to be obtained before start of construction.	n/a (conformance demonstrated through submittal of AFC)
Global Warming Solutions Act and other GHG reduction measures	Minimize emissions of GHG from all sources in CA	CEC and CARB	After project review, issues conditions of certification requiring reporting of GHG emissions	CEC approval of AFC, including all conditions contained in FDOC, to be obtained before start of construction.	§5.1.7.2.2; p. 5.1-68
Local					
SJVAPCD Rule 4001 (New Source Performance Standards [NSPS])	Establishes national standards of performance for new stationary sources.	SJVAPCD with EPA oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p. 5.1-73
SJVAPCD Rule 4002 (National Emission Standards for Hazardous Air Pollutants [NESHAPs])	Establishes national emission standards for hazardous air pollutants.	SJVAPCD with EPA oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.1.3; p. 5.1-66

TABLE 5.1-45
Laws, Ordinances, Regulations, Standards, and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	Conformance (Section; Page)
SJVAPCD Rule 4102 (Nuisance)	Prohibits emissions in quantities that adversely affect public health, other businesses, or property.	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p. 5.1-73
SJVAPCD Rule 2201 (New Source Review)	NSR: Requires that preconstruction review be conducted for all proposed new or modified sources of air pollution, including BACT, emissions offsets, and air quality impact analysis.	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p. 5.1-69-73 Appendix 5.1C
SJVAPCD Rule 2520 (Title V)	Implements operating permits requirements of CAA Title V	SJVAPCD with EPA oversight	Issues amended Title V permit after review of application.	Application for amendment to be made prior to start of facility operation.	§5.1.7.3; p. 5.1-73
SJVAPCD Rule 2540 (Title IV)	Acid rain regulations of CAA Title IV.	SJVAPCD with EPA oversight	Title IV requirements incorporated into FDOC/ATC and Title V permit after review of application	Application to be submitted two years before start of facility operation. LEC not subject to this program.	§5.1.7.3; p. 5.1-73
SJVAPCD Rule 4101 (Visible Emissions)	Limits visible emissions to no darker than Ringelmann No. 2 for periods greater than 3 minutes in any hour.	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p. 5.1-73
SJVAPCD Rule 4201 (Particulate Matter Concentration)	Limits PM emissions to less than 0.10 gr/dscf.	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p 5.1-73
SJVAPCD Rules 4306 and 4320 (proposed) (Boilers, Steam Generators and Process Heaters)	Limits NO_x and CO emissions from boilers, steam generator and process heaters	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p 5.1-73
SJVAPCD Rule 4703 (Stationary Gas Turbines)	Limits NO_x emissions from gas turbines	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p. 5.1-73

TABLE 5.1-45
Laws, Ordinances, Regulations, Standards, and Permits for Protection of Air Quality

LORS	Purpose	Regulating Agency	Permit or Approval	Schedule and Status of Permit	Conformance (Section; Page)
SJVAPCD Rule 4801 (Sulfur Compound Emissions)	Limits sulfur emissions from permitted sources	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.7.3; p. 5.1-73
SJVAPCD Regulation VIII (Fugitive PM_{10} Prohibition)	Requires control of fugitive PM_{10} emissions from various sources	SJVAPCD with CARB oversight	After project review, issues FDOC/ATC with conditions limiting emissions.	Agency approval to be obtained before start of construction.	§5.1.3.8; p. 5.1-32-33 Appendix 5.1E §5.1.7.3; p. 5.1-74

5.1.7.4 Screening Health Risk Assessment

Pursuant to the SJVAPCD Integrated Air Toxics program, a health risk screening must be executed to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the proposed project. The impact on public health due to the emission of these compounds was assessed utilizing air pollutant dispersion models.

A screening health risk assessment has been prepared that includes the CTG/HRSG and the auxiliary boiler. The results of the revised screening health risk assessment are presented in Table 5.1-46R. A detailed discussion of the screening health risk assessment procedures and assumptions is provided in Appendix 5.1D to this application.

TABLE 5.1-46R
Screening Health Risk Assessment Results

Source	Residential Cancer Risk (in one million)	Worker Cancer Risk (in one million)	Chronic Health Hazard Index	Acute Health Hazard Index
Gas Turbine/ HRSG, Aux. Boiler	0.45~~0.43~~	0.07~~0.04~~	0.006~~0.08~~	0.01~~0.05~~

The maximum cancer risk from the facility is well below the 1 in one million level that is considered to be significant. The acute and chronic health hazard indices are well below 1.0.

5.1.8 Cumulative Air Quality Impacts Analysis

An analysis of potential cumulative air quality impacts that may result from the project and other reasonably foreseeable projects is generally required only when project impacts are significant.

To ensure that potential cumulative impacts of the project and other nearby projects are adequately considered, a cumulative impacts analysis has been conducted in accordance with the protocol included as Appendix 5.1G. The analysis demonstrates that the project will not cause or contribute to any significant cumulative air quality impacts.

5.1.9 Mitigation Measures

Mitigation will be provided for project emissions in the form of offsets and the installation of BACT, as required under SJVAPCD regulations. The cumulative air quality impacts analysis described in Appendix 5.1G shows that the project will not result in significant cumulative impacts and that sufficient ERCs are being provided to mitigate all project emissions.

5.1.10 Agencies and Agency Contacts

Each level of government has adopted specific regulations that limit emissions from stationary combustion sources, several of which are applicable to this project. The other air agencies having permitting authority for this project are shown in Table 5.1-47. The applicable federal LORS and compliance with these requirements were discussed in detail in Sections 5.1-6 and 5.1-7 above. The SJVAPCD will review the application for a District permit. It will provide the CEC with a Determination of Compliance, which provides the CEC with information on what the facility must do in order to be in compliance with air quality requirements. Additionally, the SJVAPCD is responsible for issuance of the federal Operating (Title V) permit. An application for the federal permit will be submitted in a timely fashion.

TABLE 5.1-47
Agency Contacts for Air Quality

Agency	Authority	Contact
EPA Region IX	PSD permit issuance, enforcement	Gerardo Rios, Chief Permits Office EPA Region IX 75 Hawthorne Street San Francisco, CA 94105 (415) 744-1259
California Air Resources Board	Regulatory oversight	Mike Tollstrup, Chief Project Assessment Branch California Air Resources Board 2020 L Street Sacramento, CA 95814 (916) 322-6026
San Joaquin Valley Air Pollution Control District	Permit issuance, enforcement	Rupi Gill San Joaquin Valley Air Pollution Control District 4800 Enterprise Way Modesto, CA 95356-8712 (209) 557-6446

5.1.11 Permits and Permit Schedule

An Authority to Construct is required in accordance with SJVAPCD Rule 2010. A complete application for an Authority to Construct was~~is being~~ filed with the SJVAPCD in September 2008; a ~~prior to submittal to the CEC of the complete AFC. A~~ PDOC was issued on April 15, 2009. The District will revise the PDOC to reflect the changes proposed in this supplement; a revised PDOC (or FDOC) is expected within approximately 60~~180~~ days after submittal of the supplement~~acceptance of the permit application as complete~~, or by approximately September 15, 2009~~March 1, 2009~~.

The project will also require a PSD permit from EPA. A~~The~~ PSD permit application was filed with EPA Region 9 at approximately the same time as the original application for an ATC was filed with the District; the supplemental information regarding proposed changes to the project will also be filed with EPA at approximately the same time as the information is provided to the District ~~within a week of submittal of the AFC~~.

5.1.12 References

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Nappo, C. J. et al. (1982). *The Workshop on the Representativeness of Meteorological Observations*, June 1981, Boulder, Co. Bull. Amer. Meteor. Soc., Vol. 63, No. 7, pp. 761-764. American Meteorological Society, Boston, MA.

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Stull, Roland B. 1988. An Introduction to Boundary Layer Meteorology, Chapter 9.

U.S. Department of Commerce, Weather Bureau. 1959. Climate of the States—California. December.

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U.S. Environmental Protection Agency (EPA). 1990. *New Source Review Workshop Manual – Draft*. Office of Air Quality Planning and Standards, Research Triangle Park, NC.

U.S. Environmental Protection Agency (EPA). 1992. Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised, EPA-454/R-92-019. October.

U.S. Environmental Protection Agency (EPA). 1995. On-Site Meteorological Program Guidance for Regulatory Model Applications, EPA-450/4-87-013. August.

U.S. Environmental Protection Agency (EPA). 2000. Compilation of Emission Factors. AP-42. Revised July.

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U.S. Environmental Protection Agency (EPA). 2005. AERMOD Implementation Guide, www.epa.gov/scram001/17thconf/aermod. September 17.

U.S. Environmental Protection Agency (EPA). 2005. 40 CFR Part 51, Appendix W. *Guideline on Air Quality Models*. Last update November 9, 2005.

Appendix D
Revised Air Quality Appendixes

APPENDIX 5.1A

Revised July 2009

Emissions and Operating Parameters

APPENDIX 5.1A (REVISED JULY 2009)

Emissions and Operating Parameters

The following tables are provided in this appendix:

Table 5.1A-1
NCPA Lodi Energy Center
Emissions from the Existing Gas Turbine

Parameter	
Standard Temp (F)	60
Heat Input Rate (MMBtu/hr)	463
Power Generation (MW)	49
Exhaust O2 Conc	0.00%
CO2 F-Factor (dscf/MMBtu)	1,040
Exhaust Flow Rate (dscfm)	67,212
Higher Heating Value (Btu/lb)	22,525
Daily Operating Hours	24
Annual Operating Days	365

Device	Gas Turbine
Make	General Electric
Model	LM5000
Fuel	Natural Gas

Pollutant	Exhaust Concentration (ppmvd @ 15% O2)	Emission Factors (lb/MMBtu)	Maximum Emissions Hourly (lb)	Daily (lb)	Annual (tons)
CO	13	0.029	13.4	322	58.8
NOx	3.0	0.011	5.20	112	20.4
PM10 ---->gr/dscf	0.0035	0.004	2.0	48	8.8
SOx (as SO2)	0.5	0.0028	1.30	31	5.7
VOC (as CH4)	10	0.0128	5.92	142	25.9

Notes
1. Standard temperature as specified in Section 3.47 of Rule 1020 of the SJVUAPCD Rules and Regulations.
2. Fuel consumption (in MMBtu/hr) is limited by Permit Condtion 22.
3. Power generation is specified in the Permit to Operate.
4. Exhaust O2 concentration corresponds to the USPEPA f-factor.
5. CO2 F-factor obtained from 40 CFR Part 60, Method 19.
6. Exhaust flow rate calculated from heat input rate and the USEPA F-factor from 40 CFR Part 60, Method 19.
7. Fuel sulfur content (in gr/100 scf) is limited by Permit Condition 35.
8. Higher heating value (in Btu/lb) corresponds to a higher heating value of 1,004 Btu/scf.
9. Daily NOx, CO, and VOC emissions are limited by Permit Conditions 31, 33, and 34, respectively. Hourly emissions of CO and VOC were calculated from the daily emissions and the daily operating hours. Exhaust concentrations (in ppmv @ 15% O2) were calculated from the hourly emission rate, exhaust flow rate, exhaust O2 concentration, and reference O2 concentration. Hourly NOx mass emissions were calculated from the NOx concentration limit in Condition 27.
10. Daily PM10 emissions are limited by Permit Condition 22. Hourly emissions were calculated from the daily emissions and the daily operating hours. Exhaust PM10 concentration (in gr/dscf @ 12% CO2) was calculated from the hourly emission rate, heat input rate, CO F-factor, and reference CO2 concentration.
11. Hourly SOx emissions were calculated from the heat input rate (in MMBtu/hr), the higher heating value (in Btu/lb), and the fuel sulfur content (in gr/100 scf). Daily SOx emissions were calculated from the hourly emissions and the daily operating hours. Exhaust SOx concentration (in ppmv @ 15% O2) was calculated from the hourly emission rate, exhaust flow rate, exhaust O2 concentration, and reference O2 concentration.
12. Except for SO2, emission factors (in lb/MMBtu) were calculated from the hourly emission rate (in lb/hr) and the heat input rate (MMBtu/hr). For SO2, the emission factor (in lb/MMBtu) was calculated from the fuel sulfur content limit and the heat content of the natural gas fuel.
13. Annual emissions were calculated from the daily emissions and annual operating days.

Table 5.1A-2
NCPA Lodi Energy Center
Emissions from the Existing Emergency Diesel Fire Pump Engine

Parameter	
Power Output (bhp)	240
Fuel Consumption (Btu/hp-hr)	6,700
Higher Heating Value (Btu/gal)	135,100
Fuel Density (lb/gal)	7.0
Fuel Sulfur Content, wt	0.015%
Heat Input Rate (MMBtu/hr)	1.6
Exhaust Rate (dscfm @ 15% O2)	872
Exhaust Rate (dscfm @ 12% CO2)	317
Daily Operating Hours	24
Annual Operating Hours	50

Device	IC Engine
Make	Cummins
Model	6CTA8.3-F1
Fuel	Diesel

Pollutant	Exhaust Concentraton (ppmvd @ 15% O2)	Emission Factors (lb/bhp-hr)	Maximum Emissions Hourly (lb)	Daily (lb)	Annual (tons)
CO	423	0.00668	1.6	38	0.04
NOx	520	0.013	3.2	78	0.08
PM10 ---->gr/dscf @ 12% O2	0.10	0.00110	0.26	6	0.01
SOx	2.9	0.00010	0.02	0.6	0.00
VOC (as CH4)	274	0.00247	0.59	14	0.01

Notes

1. Power output (in bhp) was specified in the Permit to Operate.
2. Fuel consumption (in gal/hr) and higher heating value (in Btu/gal) were obtained from Table 3.3-1 of AP-
3. Fuel density (lb/gal) reflects the typical value for diesel.
4. Fuel sulfur content (in wt%) and annual operating hours are limited by the ATCM.
5. Heat input rate was calcuated from the power output (in bhp), fuel consumption rate (in Btu/hp-hr), and higher heating value (in Btu/gal).
6. Exhaust flow rates at reference concentrations were calculated from the heat input rate and F-factors from 40 CFR Part 60 Method 19.
7. CO, NOx, PM10, and VOC emission factors (in lb/bhp-hr) were obtained from Table 3.3-1 of AP-42.
8. SOx emission factor (in g/bhp-hr) was calculated from the fuel consumption rate (in Btu/hp-hr), the higher heating value (in Btu/gal), the fuel density (in lb/gal), and the fuel sulfur content (in weight %).
9. Hourly emissions were calculated from the emissions factor (in g/bhp-hr) and the power output (in bhp). Daily and annual emissions were calculated from the hourly emissions and the corresponding operating
10. Exhaust CO, NOx, SOx, and VOC concentrations (in ppmvd @ 15% O2) were calculated from the hourly emission rates and the exhaust flow rate at the reference O2 or CO2 concentrations. Exhaust PM and PM10 concentrations (in gr/dscf @ 12% CO2) were calculated from the hourly emission rates and the exhaust flow rate at the reference CO2 concentration.

Table 5.1A-3R
NCPA Lodi Energy Center
Emissions and Operating Parameters for the CTG/HRSG
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

Case	Cold Base	Cold Low	Avg. Base	Avg. Low	Hot Base	Hot Low
CTG Gross Power, MW	184.6	92.3	171.0	85.5	159.4	79.7
Ambient Temp, F	32.6	32.6	61.2	61.2	94	94
Turbine Load, %						
Evap Cooler On/Off	Off	Off	On	On	On	On
CTG heat input, MMBtu/hr (HHV)	2142.1	1302.8	1998.0	1225.8	1902.4	1119.6
Total heat input, MMBtu/hr (HHV)	2142.1	1302.8	1998.0	1225.8	1902.4	1119.6
Stack flow, lb/hr	4,272,333	2,960,443	4,004,123	2,876,462	3,854,442	2,761,234
Stack flow, acfm	1,185,012	797,965	1,116,524	780,840	1,084,352	753,644
Stack flow, dscfm	879,405	614,021	818,739	594,675	777,878	570,925
Stack temp, F	186	169	187	172	188	175
Stack exhaust, vol %						
O2 (dry)	13.72%	14.65%	13.71%	14.83%	13.69%	15.13%
CO2 (dry)	4.11%	3.58%	4.12%	3.48%	4.13%	3.31%
H2O	7.81%	6.92%	8.76%	7.44%	10.61%	7.49%
Emissions						
NOx, ppmvd @ 15% O2	2.0	2.0	2.0	2.0	2.0	2.0
NOx, lb/hr	15.54	9.45	14.49	8.89	13.80	8.12
NOx, lb/MMBtu	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073
SO2, ppmvd @ 15% O2	0.56	0.56	0.56	0.56	0.56	0.56
SO2, lb/hr (short-term)	6.10	3.71	5.69	3.49	5.42	3.19
SO2, lb/MMBtu (short-term)	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028
SO2, lb/hr (long-term)	6.10	3.71	5.69	3.49	5.42	3.19
SO2, lb/MMBtu (long-term)	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028
CO, ppmvd @ 15% O2	3.0	3.0	3.0	3.0	3.0	3.0
CO, lb/hr	14.19	8.63	13.23	8.12	12.60	7.42
CO, lb/MMBtu	0.0066	0.0066	0.0066	0.0066	0.0066	0.0066
VOC, ppmvd @ 15% O2	1.40	1.40	1.40	1.40	1.40	1.40
VOC, lb/hr	3.79	2.31	3.54	2.17	3.37	1.98
VOC, lb/MMBtu	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018
PM10, lb/hr	9.0	9.0	9.0	9.0	9.0	9.0
PM10, lb/MMBtu	0.0042	0.0069	0.0045	0.0073	0.0047	0.0080
PM10, gr/dscf	0.00119	0.00171	0.00128	0.00177	0.00135	0.00184
NH3, ppmvd@15% O2	10.0	10.0	10.0	10.0	10.0	10.0
NH3, lb/hr	28.76	17.49	26.82	16.46	25.54	15.03

Table 5.1A-4R
NCPA Lodi Energy Center
Emissions and Operating Parameters for Auxiliary Boiler
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

Boiler Emission Characteristics

Auxiliary Boiler, MMBtu/hr (HHV)	36.5
Boiler Rating, lb/hr	30,000
NOx, ppmvd @ 3% O2	7.00
CO, ppmvd @ 3% O2	50.00
VOC (as CH4), ppmvd @ 3% O2	10.00
NOx (as NO2), lb/hr	0.31
NOx, lb/MMBtu	0.0084
CO, lb/hr	1.34
CO, lb/MMBtu	0.0366
VOC (as CH4), lb/hr	0.15
VOC, lb/MMBtu	0.0042
PM10, lb/hr	0.28
PM10, lb/MMBtu	0.0077
SO2, grains/100 scf	1.0
SO2, lb/hr	0.10
SO2, lb/MMBtu	0.0028

Table 5.1A-5R
NCPA Lodi Energy Center
Calculation of Cooling Tower Emissions
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

Typical Worst-Case Design Parameters	
Water Flow Rate, 10E6 lbm/hr	34.49
Water Flow Rate, gal/min	69,000
Drift Rate, %	0.0005
Drift, lbm water/hr	172.43
PM10 Emissions based on TDS Level	
TDS level, ppm (from W-P specs)	5400
PM10, lb/hr	0.93
PM10, lb/day	22.3
PM10, tpy	4.08

Based on 8760 hrs/yr

Table 5.1A-6R
NCPA Lodi Energy Center
Calculations for Maximum Hourly, Daily, Quarterly and Annual Criteria Pollutant Emissions
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

	CTG/HRSG					Max Possible CTG/HRSG Hours (SO2, PM10)	Auxiliary Boiler Total Hours	
Assumptions for Daily and Annual Ops:	**Hot Start Hours**	**Cold Start Hours**	**Shutdown Hours**	**Base Load Hours**	**Total Hours (NOx, CO, VOC)**			
Daily	0	6		18	24	24	24	per day
Q1	100	42	included in startup hours	1534	1676	2160	1000	per quarter
Q2	100	42		1558	1700	2184	1000	per quarter
Q3	40	36		1900	1976	2208	1000	per quarter
Q4	72	36		1740	1848	2208	1000	per quarter

	Hourly Emission Rates						
Equipment	max. hour	NOx (lbs/hr)	SOx (lbs/hr)	CO (lbs/hr)	VOC (lbs/hr)	PM10 (lbs/hr)	NH3 (lbs/hr)
Gas Turbine, base	1	15.54	6.10	14.19	3.79	9.00	28.76
Gas Turbine, startups/shutdowns	0	100.00	6.10	900.00	16.00	9.00	28.76
Auxiliary Boiler	1	0.31	0.10	1.34	0.15	0.28	0
Cooling Tower	1	0	0	0	0	0.93	0

Table 5.1A-6R (cont'd)

Equipment	Max lb/hr	Max lb/day	Max lb/Q1	Max lb/Q2	Max lb/Q3	Max lb/Q4	Total tons/yr
	NOx Emissions						
Gas Turbine, base	15.5	279.7	23,833.2	24,206.1	29,519.6	27,033.8	52.3
Gas Turbine, startups/shutdowns	160.0	600.0	14,200.0	14,200.0	7,600.0	10,800.0	23.4
Auxiliary Boiler	0.3	7.4	307.4	307.4	307.4	307.4	0.61
Cooling Tower	0	0	0	0	0	0	0
Total, CTG/HRSG only	160.0	879.7	38,033.2	38,406.1	37,119.6	37,833.8	75.7
Total	160.3	887.0	38,340.6	38,713.4	37,427.0	38,141.1	76.3

Equipment	Max lb/hr	Max lb/day	Max lb/Q1	Max lb/Q2	Max lb/Q3	Max lb/Q4	Total tons/yr
	SOx Emissions						
Gas Turbine, base	6.1	109.8	12,308.8	12,455.2	13,004.1	12,808.9	25.3
Gas Turbine, startups/shutdowns	0.0	36.6	866.1	866.1	463.6	658.7	1.4
Auxiliary Boiler	0.1	2.5	104.1	104.1	104.1	104.1	0.21
Cooling Tower	0	0	0	0	0	0	0
Total, CTG/HRSG only	6.1	146.4	13,174.9	13,321.3	13,467.7	13,467.7	26.7
Total	6.2	148.9	13,279.0	13,425.4	13,571.8	13,571.8	26.9

Equipment	Max lb/hr	Max lb/day	Max lb/Q1	Max lb/Q2	Max lb/Q3	Max lb/Q4	Total tons/yr
	CO Emissions						
Gas Turbine, base	14.2	255.4	21,766.3	22,106.8	26,959.5	24,689.3	47.8
Gas Turbine, startups/shutdowns	900.0	5,400.0	127,800.0	127,800.0	68,400.0	97,200.0	210.6
Auxiliary Boiler	1.3	32.1	1,337.5	1,337.5	1,337.5	1,337.5	2.7
Cooling Tower	0	0	0	0	0	0	0
Total, CTG/HRSG only	900.0	5,655.4	149,566.3	149,906.8	95,359.5	121,889.3	258.4
Total	901.3	5,687.5	150,903.7	151,244.3	96,697.0	123,226.7	261.0

Equipment	Max lb/hr	Max lb/day	Max lb/Q1	Max lb/Q2	Max lb/Q3	Max lb/Q4	Total tons/yr
	VOC Emissions						
Gas Turbine, base	3.8	68.3	5,817.9	5,908.9	7,206.0	6,599.2	12.8
Gas Turbine, startups/shutdowns	16.0	96.0	2,272.0	2,272.0	1,216.0	1,728.0	3.7
Auxiliary Boiler	0.2	3.7	153.3	153.3	153.3	153.3	0.3
Cooling Tower	0	0	0	0	0	0	0
Total, CTG/HRSG only	16.0	164.3	8,089.9	8,180.9	8,422.0	8,327.2	16.5
Total	16.2	167.9	8,243.2	8,334.2	8,575.3	8,480.4	16.8

Equipment	Max lb/hr	Max lb/day	Max lb/Q1	Max lb/Q2	Max lb/Q3	Max lb/Q4	Total tons/yr
	PM10/PM2.5 Emissions						
Gas Turbine, base	9.0	162.0	18,162.0	18,378.0	19,188.0	18,900.0	37.3
Gas Turbine, startups/shutdowns	0.0	54.0	1,278.0	1,278.0	684.0	972.0	2.1
Auxiliary Boiler	0.3	6.7	280.0	280.0	280.0	280.0	0.6
Cooling Tower	0.9	22.3	2,011.2	2,033.6	2,055.9	2,055.9	4.1
Total, CTG/HRSG only	9.0	216.0	19,440.0	19,656.0	19,872.0	19,872.0	39.4
Total	10.2	245.1	21,731.2	21,969.6	22,207.9	22,207.9	44.1

Equipment	Max lb/hr	Max lb/day	Max lb/Q1	Max lb/Q2	Max lb/Q3	Max lb/Q4	Total tons/yr
	NH3 Emissions						
Gas Turbine, base	28.8	517.6	58,034.1	58,724.3	61,312.5	60,392.3	119.2
Gas Turbine, startups/shutdowns	0.0	172.5	4,083.7	4,083.7	2,185.6	3,105.9	6.7
Auxiliary Boiler	0	0	0	0	0	0	0
Cooling Tower	0	0	0	0	0	0	0
Total, CTG/HRSG only	28.8	690.2	62,117.8	62,808.0	63,498.2	63,498.2	126.0
Total	28.8	690.2	62,117.8	62,808.0	63,498.2	63,498.2	126.0

Table 5.1A-7R
NCPA Lodi Energy Center
Greenhouse Gas Emissions Calculations
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

Unit	Rated Capacity, MW (Note 1)	Operating Hours per year	Fuel Use, MMBtu/yr (1)	Estimated Gross MWh	Maximum Emissions, metric tonnes/yr				Estimated Emissions, metric tonnes/MWh		
					CO2	CH4	N2O	SF6	CO2	CH4	N2O
CTG, base load	298	8760	17,502,480	2,610,480	925,356	15.75	1.75	--	0.354	6.03E-06	6.70E-07
Auxiliary boiler	n/a	4000	146,199	n/a	7,730	0.13	0.01	--	n/a	n/a	n/a
Total	--	--	17,648,679	2,610,480	933,086	15.88	1.76	9.45E-04	0.357	6.08E-06	6.76E-07
CO2-Equivalent					933,086	333.56	547.11	22.60			

Natural Gas GHG Emission Rates (2)

	Emission Factors, kg/MMBtu			Emission Factor
	CO2 (3)	CH4 (4)	N2O (5)	SF6 (6)
Natural Gas	52.870	9.00E-04	1.00E-04	n/a
Global Warming Potential (4)	1	21	310	23,900

Notes: 1. Rated capacity and heat input from heat balance at annual average conditions, annual fuel use and gross generation based on 100% capacity factor.
2. Calculation methods and emission factors from ARB, "Regulation for the Mandatory Reporting of Greenhouse Gas Emissions," December 5, 2007 (Staff's Suggested Modifications to the Originally Proposed Regulation Order Released October 19, 2007). http://www.arb.ca.gov/cc/ccei/reporting/GHGReportRegUpdate12_05_07.pdf
3. Appendix A, Table 4; heat content 1000 to 1025 Btu/scf.
4. Appendix A, Table 6.
5. Appendix A, Table 2.
6. Sulfur hexafluoride (SF6) will be used as an insulating medium in one new 230 kV breaker. Estimates of the SF6 contained in a breaker of this size range from 161 to 208 lbs, depending on the manufacturer. Breaker manufacturers guarantee leakage rates below 1%, so a maximum leakage rate of 1% per year is assumed.

Table 5.1A-8R
NCPA Lodi Energy Center
Calculation of Noncriteria Pollutant Emissions from the CTG/HRSG
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

Compound	Emission Factor, lb/MMBtu (1)	Maximum Hourly Emissions, lb/hr (2)	Total Annual Emissions (3)	
			lb/yr	tpy
Ammonia	(4)	28.76	251,922.1	126.0
Propylene	7.68E-04	1.64	14,410.2	7.2
Hazardous Air Pollutants				
Acetaldehyde	4.00E-05	8.57E-02	750.6	0.38
Acrolein	6.40E-06	1.37E-02	120.1	6.00E-02
Benzene	1.20E-05	2.57E-02	225.2	1.13E-01
1,3-Butadiene	4.30E-07	9.21E-04	8.1	4.03E-03
Ethylbenzene	3.20E-05	6.85E-02	600.5	3.00E-01
Formaldehyde	7.10E-04	1.52	13,323.1	6.66
Hexane	2.58E-04	0.55	4,840.8	2.42
Naphthalene	1.30E-06	2.78E-03	24.4	1.22E-02
PAHs (5)	9.00E-07	1.93E-03	16.9	8.44E-03
Propylene oxide	4.76E-05	1.02E-01	893.2	0.45
Toluene	1.30E-04	2.78E-01	2,439.4	1.22
Xylene	6.40E-05	1.37E-01	1,201.0	0.60
Total HAPs		2.79	24,443.2	12.22

Notes:
(1) All factors except individual PAHs, hexane and propylene from AP-42, Table 3.4-1. Individual PAHs, hexane and propylene are CATEF mean results as AP-42 does not include factors for these compounds. MMscf converted to MMBtu using typical fuel analysis.
(2) Based on maximum hourly turbine fuel use of 2,142 MMBtu/hr (HHV)
(3) Based on total annual fuel use of 18,764,985 MMBtu/yr
(4) Based on 10 ppm ammonia slip from SCR system.
(5) Emission factors for individual PAHs adjusted proportionally so that total of "Adjusted EF" plus naphthalene equals Total PAH EF of 2.2 E-06 lb/MMBtu shown in AP-42, Table 3.4-1.

	Mean EF (Note 1)	Adjusted EF (Note 5)	Emissions	
			lb/hr	tpy
Benzo(a)anthracene	2.25E-08	1.55E-07	3.33E-04	1.46E-03
Benzo(a)pyrene	1.38E-08	9.55E-08	2.05E-04	8.96E-04
Benzo(b)fluoranthrene	1.13E-08	7.76E-08	1.66E-04	7.28E-04
Benzo(k)fluoranthrene	1.10E-08	7.56E-08	1.62E-04	7.09E-04
Chrysene	2.51E-08	1.73E-07	3.71E-04	1.62E-03
Dibenz(a,h)anthracene	2.34E-08	1.61E-07	3.46E-04	1.51E-03
Indeno(1,2,3-cd)pyrene	2.34E-08	1.61E-07	3.46E-04	1.51E-03
Total	1.30E-07	9.00E-07	1.93E-03	8.44E-03

Table 5.1A-9R
NCPA Lodi Energy Center
Calculation of Noncriteria Pollutant Emissions from Auxiliary Boiler
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

Compound	Emission Factor, lb/MMscf (1)	Hourly Emissions, lb/hr (2)	Total Annual Emissions (3) lb/yr	tpy
Propylene	5.30E-01	1.93E-02	77.1	3.86E-02
Hazardous Air Pollutants				
Acetaldehyde	3.10E-03	1.13E-04	0.5	2.26E-04
Acrolein	2.70E-03	9.83E-05	0.4	1.97E-04
Benzene	5.80E-03	2.11E-04	0.8	4.22E-04
1,3-Butadiene	n/a	--	--	--
Ethylbenzene	6.90E-03	2.51E-04	1.0	5.02E-04
Formaldehyde	1.23E-02	4.48E-04	1.8	8.95E-04
Hexane	4.60E-03	1.67E-04	0.7	3.35E-04
Naphthalene	3.00E-04	1.09E-05	4.4E-02	2.18E-05
PAHs (4)	1.00E-04	3.64E-06	1.5E-02	7.28E-06
Propylene oxide	n/a	--	--	--
Toluene	2.65E-02	9.64E-04	3.9	1.93E-03
Xylene	1.97E-02	7.17E-04	2.9	1.43E-03
Total HAPs			11.9	5.97E-03

Notes:
(1) All factors from Ventura County APCD, "AB2588 Combustion Emission Factors," Natural Gas Fired External Combustion Equipment 10-100 MMBtu/hr. Available at http://www.vcapcd.org/pubs/Engineering/AirToxics/combem.pdf
(2) Based on maximum hourly heat input of 36390 scf/hr
(3) Based on total annual fuel use of 145.6 MMscf/yr
(4) Total PAHs, excluding naphthalene. See speciation below.
(5) Emission factors for individual PAHs obtained from AP-42, Table 1.4-3, then adjusted proportionally so that total of "Adjusted EF" equals Total PAH EF of 1.0 E-04 lb/MMscf per Ventura County factors.

Speciated PAHs (except naphthalene)

	Mean EF (Note 1)	Adjusted EF (Note 5)	Emissions lb/hr	tpy
Benzo(a)anthracene	1.80E-06	1.58E-05	5.75E-07	1.15E-06
Benzo(a)pyrene	1.20E-06	1.05E-05	3.83E-07	7.66E-07
Benzo(b)fluoranthrene	1.80E-06	1.58E-05	5.75E-07	1.15E-06
Benzo(k)fluoranthrene	1.80E-06	1.58E-05	5.75E-07	1.15E-06
Chrysene	1.80E-06	1.58E-05	5.75E-07	1.15E-06
Dibenz(a,h)anthracene	1.20E-06	1.05E-05	3.83E-07	7.66E-07
Indeno(1,2,3-cd)pyrene	1.80E-06	1.58E-05	5.75E-07	1.15E-06
Total	1.14E-05	1.00E-04	3.64E-06	7.28E-06

Table 5.1A-10R
NCPA Lodi Energy Center
Calculation of Noncriteria Pollutant Emissions from Cooling Tower
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

Constituent	Concentration in Cooling Tower Return Water		Emissions (1) Emissions, lb/hr	Emissions, ton/yr	Emissions, lbs/year
Ammonia	0.02	ppm	3.45E-06	1.51E-05	0.0
Copper	0.025	ppm	4.31E-06	1.89E-05	0.0
Silver	0	ppm	0.00E+00	0.00E+00	0.0
Zinc	0.025	ppm	4.31E-06	1.89E-05	0.0
Hazardous Air Pollutants					
Arsenic	0	ppm	0.00E+00	0.00E+00	0.000
Cadmium	0.025	ppm	4.31E-06	1.89E-05	0.038
Chromium (III)	0.025	ppm	4.31E-06	1.89E-05	0.038
Lead	0.05	ppm	8.62E-06	3.78E-05	0.076
Mercury	0	ppm	0.00E+00	0.00E+00	0.000
Nickel	0.025	ppm	4.31E-06	1.89E-05	0.038
Dioxins/furans	--	ppm	--	--	--
PAHs	--		--	--	--
Total HAPs				9.44E-05	0.19

Note: (1) Emissions calculated from maximum drift rate of 172.43 lb/hr.

Table 5.1A-11R
NCPA Lodi Energy Center
Calculation of Noncriteria Pollutant Emissions from the Existing Units

Gas Turbine

Parameter	
Heat Input Rate (MMBtu/hr @ HHV) (1)	463.0
Annual Operating Hours	8,760

Pollutant	Emission Factor lb/MMBtu (2)	Hourly Emissions (lb/hr)	Annual Emissions (tpy) (4)
Ammonia (3)	0.0335	15.5105	67.94
Propylene	7.68E-04	0.36	1.56
HAPs			
Acetaldehyde	4.00E-05	1.85E-02	8.11E-02
Acrolein	6.40E-06	2.96E-03	1.30E-02
Benzene	1.20E-05	5.56E-03	2.43E-02
1,3-Butadiene	4.30E-07	1.99E-04	8.72E-04
Ethylbenzene	3.20E-05	1.48E-02	6.49E-02
Formaldehyde	7.10E-04	0.33	1.44
Hexane	2.58E-04	0.12	0.52
Naphthalene	1.30E-06	6.02E-04	2.64E-03
PAHs (5)	9.00E-07	4.17E-04	1.83E-03
Benz(a)anthracene	1.55E-07	7.19E-05	4.56E-05
Benzo(a)pyrene	9.55E-08	4.42E-05	2.81E-05
Benzo(b)fluoranthene	7.76E-08	3.59E-05	2.28E-05
Benzo(k)fluoranthene	7.56E-08	3.50E-05	2.22E-05
Chrysene	1.73E-07	8.02E-05	5.09E-05
Dibenz(a,h)anthracene	1.61E-07	7.48E-05	4.75E-05
Indeno(1,2,3-cd)pyrene	1.61E-07	7.48E-05	4.75E-05
Propylene oxide	4.76E-05	2.20E-02	0.10
Toluene	1.30E-04	6.02E-02	0.26
Xylene	6.40E-05	2.96E-02	0.13
TOTAL HAPS			2.64

Notes
1. Heat input rate (in MMBtu/hr) is limited by Permit Condtion 28.
2. All factors except individual PAHs, hexane and propylene from AP-42, Table 3.4-1.
   Individual PAHs, hexane and propylene are CATEF mean results as AP-42 does not include factors for these compounds. MMscf converted to MMBtu using typical fuel analysis.
3. Based on permitted ammonia slip limit of 25 ppmc.
4. Annual TAC emissions were calculated from the emission factor (in lb/MMBtu), the heat input rate in MMBtu/hr), and annual operating hours.
5. Emission factors for individual PAHs adjusted proportionally so that total of "Adjusted EF" plus naphthalene equals Total PAH EF of 2.2 E-06 lb/MMBtu shown in AP-42, Table 3.4-1.

	Mean EF lb/MMBtu (2)	Adjusted EF lb/MMBtu (5)	Emissions lb/hr	Emissions tpy
Benzo(a)anthracene	2.25E-08	1.55E-07	1.04E-05	4.56E-05
Benzo(a)pyrene	1.38E-08	9.55E-08	6.41E-06	2.81E-05
Benzo(b)fluoranthrene	1.13E-08	7.76E-08	5.21E-06	2.28E-05
Benzo(k)fluoranthrene	1.10E-08	7.56E-08	5.07E-06	2.22E-05
Chrysene	2.51E-08	1.73E-07	1.16E-05	5.09E-05
Dibenz(a,h)anthracene	2.34E-08	1.61E-07	1.08E-05	4.75E-05
Indeno(1,2,3-cd)pyrene	2.34E-08	1.61E-07	1.08E-05	4.75E-05
Total	1.30E-07	9.00E-07	6.04E-05	2.65E-04

Table 5.1A-11R (cont'd)
Emergency Diesel Fire Pump Engine

Parameter	Maximum Daily
Power Output (bhp)	240
Fuel Consumption (Btu/hp-hr)	6,700
Higher Heating Value (Btu/gal)	135,100
Annual Operating Hours	50

Pollutant	Emission Factor (lb/bhp-hr)	Maximum Annual Emissions (tpy)
DPM (1)	1.10E-03	6.60E-03
TOTAL HAPS		0.00

Notes
1. Per ARB guidance, DPM is used as a surrogate for all TACs from Diesel ICE.
DPM is not a HAP.

APPENDIX 5.1B

Revised July 2009

Modeling Analysis

APPENDIX 5.1B (REVISED JULY 2009)

Modeling Analysis

The following tables and figures are provided in this appendix:

Table 5.1B-1R
Lodi Energy Center
Building Dimensions Used for Modeling
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

Structure	Dimensions (meters)		
	Height	Length	Width
New Structures			
Combustion Turbine	10.7	25	6
HRSG, Tier 1	12.9	23	11
HRSG, Tier 2	29.4	27	12
CTG Inlet	21.3	14	9
Main Aux transformer	3.9	10	9
Auxilary Boiler	7.7	4	3
Boiler Enclosure, Tier 1	8.4	5	2
Boiler Enclosure, Tier 2	11.1	5	1
Boiler Enclosure, Tier 3	12.2	2	1
Water Treatment	12.2	39	19
Steam Turbine	10.7	44	14
Cooling Tower	9.8	103	14
STIG Cooling Tower	6.0	9	7
Heat Exchanger 1	3.2	8	5
Heat Exchanger 2	3.2	8	5
Tank 18	12.2	15	
Tank 09	12.2	9	
Tank 34	7.3	9	
Existing Structures			
Gas Turbine Skid	5.0	17	4
Gas Turbine Inlet	11.3	11	9
HRSG, Tier 1	10.7	34	8
HRSG, Tier 2	21.2	19	8
Control Room	3.8	12	9
Old Office	3.8	12	9
Equipment room	6.2	17	15
Big Warehouse	9	32	27
Warehouse	5.7	21	18
Fire Pump Enclosure	2.7	5	3
Tank 1	9.1	12	
Tank 2	9.1	12	
Tank 3	9.1	12	
Tank 4	9.1	12	
Tank 5	9.1	12	
Tank 6	4.6	8	

Table 5.1B-2R
NCPA Lodi Energy Center
Emissions and Stack Parameters for Screening Modeling
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

Turbine Case		Ambient		Stack	Stack Ht	Exhaust Temp	Exhaust Velocity				
Number	Condition	Temp	Load	Diam (m)	(m)	(deg K)	(m/s)	NOx, g/s	SO2, g/s	CO, g/s	PM10, g/s
1	Cold Base	32.6	100%	6.71	45.720	358.556	15.836	1.958	7.685E-01	1.788	1.134
2	Cold Low	32.6	50%	6.71	45.720	349.111	10.664	1.191	4.674E-01	1.087	1.134
3	Avg. Base	61.2	100%	6.71	45.720	359.111	14.921	1.826	7.168E-01	1.668	1.134
4	Avg. Low	61.2	50%	6.71	45.720	350.778	10.435	1.120	4.398E-01	1.023	1.134
5	Hot Base	94.0	100%	6.71	45.720	359.667	14.491	1.739	6.825E-01	1.588	1.134
6	Hot Low	94.0	50%	6.71	45.720	352.444	10.072	1.023	4.017E-01	0.934	1.134

Table 5.1B-3R
NCPA Lodi Energy Center
Results of the CTG Screening Analysis
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

Case	Condition	Max. Impact, ug/m3 per 1.0 g/s					Max. Impact, ug/m3 per 1.0 g/s				
		1-hr	3-hr	8-hr	24-hr	annual	1-hr	3-hr	8-hr	24-hr	annual
		2000 Met Data					2003 Met Data				
1	Cold Base	1.896	1.516	1.247	0.673	0.103	1.535	1.087	0.902	0.395	0.107
2	Cold Low	2.893	2.260	2.041	1.126	--	2.579	1.620	1.394	0.723	--
3	Avg. Base	2.018	1.571	1.317	0.720	0.108	1.626	1.126	0.936	0.424	0.113
4	Avg. Low	2.922	2.289	2.061	1.136	--	2.597	1.626	1.405	0.730	--
5	Hot Base	2.074	1.596	1.350	0.741	0.111	1.670	1.147	0.956	0.438	0.116
6	Hot Low	2.990	2.352	2.110	1.167	--	2.654	1.650	1.435	0.750	--
		2001 Met Data					2004 Met Data				
1	Cold Base	1.912	1.430	0.957	0.500	0.105	1.551	1.256	0.894	0.549	0.110
2	Cold Low	2.543	2.173	1.382	0.840	--	2.490	1.899	1.335	0.952	--
3	Avg. Base	1.988	1.501	1.000	0.535	0.111	1.653	1.338	0.940	0.597	0.116
4	Avg. Low	2.557	2.196	1.397	0.851	--	2.510	1.918	1.357	0.960	--
5	Hot Base	2.024	1.538	1.019	0.552	0.114	1.699	1.375	0.961	0.619	0.118
6	Hot Low	2.593	2.241	1.434	0.874	--	2.563	1.961	1.402	0.981	--
		2002 Met Data					Max, All Years				
1	Cold Base	1.876	1.415	1.108	0.722	0.112	1.91163	1.51607	1.24696	0.72213	0.11152
2	Cold Low	2.738	2.272	1.829	1.180	--	2.89276	2.27217	2.04078	1.17950	--
3	Avg. Base	1.973	1.510	1.193	0.772	0.117	2.01818	1.57147	1.31725	0.77240	0.11732
4	Avg. Low	2.757	2.293	1.850	1.193	--	2.92220	2.29254	2.06100	1.19333	--
5	Hot Base	2.031	1.552	1.232	0.796	0.120	2.07356	1.59621	1.34974	0.79550	0.11999
6	Hot Low	2.799	2.341	1.898	1.225	--	2.99006	2.35184	2.10963	1.22461	--

Table 5.1B-3R (cont'd)

Turbine Case		Emission Rates for Screening Modeling (lb/hr)									
		NOx		SO2				CO		PM10	
		1-hr	annual avg	1-hr	3-hr	24-hr	annual avg	1-hr	8-hr	24-hr	annual avg
1	Cold Base	15.54	17.28	6.099	6.099	6.099	6.10	14.19	14.19	9.0	9.00
2	Cold Low	9.45	17.28	3.710	3.710	3.710	6.10	8.63	8.63	9.0	9.00
3	Avg. Base	14.49	17.28	5.689	5.689	5.689	6.10	13.23	13.23	9.0	9.00
4	Avg. Low	8.89	17.28	3.490	3.490	3.490	6.10	8.12	8.12	9.0	9.00
5	Hot Base	13.80	17.28	5.417	5.417	5.417	6.10	12.60	12.60	9.0	9.00
6	Hot Low	8.12	17.28	3.188	3.188	3.188	6.10	7.42	7.42	9.0	9.00

Turbine Case	Condition	Turbine Emission Rates for Screening Modeling (g/s)									
		NOx		SO2				CO		PM10	
		1-hr	annual avg	1-hr	3-hr	24-hr	annual avg	1-hr	8-hr	24-hr	annual avg
1	Cold Base	1.958	2.178	0.769	0.769	0.769	0.769	1.788	1.788	1.134	1.134
2	Cold Low	1.191	2.178	0.467	0.467	0.467	0.769	1.087	1.087	1.134	1.134
3	Avg. Base	1.826	2.178	0.717	0.717	0.717	0.769	1.668	1.668	1.134	1.134
4	Avg. Low	1.120	2.178	0.440	0.440	0.440	0.769	1.023	1.023	1.134	1.134
5	Hot Base	1.739	2.178	0.683	0.683	0.683	0.769	1.588	1.588	1.134	1.134
6	Hot Low	1.023	2.178	0.402	0.402	0.402	0.769	0.934	0.934	1.134	1.134

Turbine Case	Condition	Modeled Impacts, ug/m3, by Pollutant and Averaging Period									
		NOx		SO2				CO		PM10	
		1-hr	Annual	1-hr	3-hr	24-hr	Annual	1-hr	8-hr	24-hr	Annual
1	Cold Base	**3.742**	0.243	**1.4692**	**1.165**	**0.5550**	0.0857	**3.418**	**2.229**	0.819	0.126
2	Cold Low	3.444	--	1.3521	1.062	0.5513	--	3.145	2.219	1.338	--
3	Avg. Base	3.685	0.255	1.4467	1.126	0.5537	0.0902	3.365	2.197	0.876	0.133
4	Avg. Low	3.273	--	1.2851	1.008	0.5248	--	2.990	2.109	1.353	--
5	Hot Base	3.605	**0.261**	1.4153	1.089	0.5430	**0.0922**	3.292	2.143	0.902	**0.136**
6	Hot Low	3.059	--	1.2010	0.945	0.4919	--	2.794	1.971	**1.389**	--

Table 5.1B-4R
NCPA Lodi Energy Center
Emission Rates and Stack Parameters for Refined Modeling
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

	Stack Diam, m	Release Height m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rates, g/s			
						NOx	SO2	CO	PM10
Averaging Period: One hour									
Gas Turbine (Case 1)	6.706	45.720	358.56	559.263	15.836	1.9576	0.7685	1.788	n/a
Aux Boiler	0.762	19.812	421.89	5.101	11.186	0.0387	1.311E-02	0.169	n/a
Averaging Period: Three hours									
Gas Turbine (Case 1)	6.706	45.720	358.56	559.263	15.836	n/a	0.7685	n/a	n/a
Aux Boiler	0.762	19.812	421.89	5.101	11.186	n/a	1.311E-02	n/a	n/a
Averaging Period: Eight hours									
Gas Turbine (Case 1)	6.706	45.720	358.56	559.263	15.836	n/a	n/a	85.4970	n/a
Aux Boiler	0.762	19.812	421.89	5.101	11.186	n/a	n/a	1.685E-01	n/a
Averaging Period: 24-hour PM10									
Gas Turbine (Case 6)	6.706	45.720	352.44	355.681	10.072	n/a	n/a	n/a	1.1340
Aux Boiler	0.762	19.812	421.89	5.101	11.186	n/a	n/a	n/a	3.528E-02
Cooling Tower (per cell, 7 cells)	8.534	13.960	304.56	78.208	7.498	n/a	n/a	n/a	1.676E-02
Averaging Period: 24-hour SO2									
Gas Turbine (Case 1)	6.706	45.720	358.56	559.263	15.836	n/a	0.7685	n/a	n/a
Aux Boiler	0.762	19.812	421.89	5.101	11.186	n/a	1.311E-02	n/a	n/a
Averaging Period: Annual									
Gas Turbine (Case 5)	6.706	45.720	359.67	511.757	14.491	2.1776	0.7685	n/a	1.1340
Aux Boiler	0.762	19.812	421.89	5.101	11.186	1.768E-02	5.988E-03	n/a	1.611E-02
Cooling Tower (per cell, 7 cells)	8.534	13.960	304.56	78.208	7.498	n/a	n/a	n/a	1.676E-02

Table 5.1B-5R
NCPA Lodi Energy Center
Emission Rates and Stack Parameters for Modeling Startup Impacts
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

	Stack Diam, m	Stack Height, m	Exh Temp, Deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Em Rates, g/s	
						NOx	CO
Gas Turbine/HRSG Case 2)	6.706	45.720	349.111	376.597	10.664	20.16	113.40
Auxiliary Boiler	0.762	19.812	421.889	5.101	11.186	3.87E-02	0.17

Table 5.1B-6R
NCPA Lodi Energy Center
Calculation of Inversion Fumigation Impacts
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing
CTG Emission Rates, g/s

Case	NOx	SO2	CO	PM10
1	1.958	0.769	1.788	1.134
2	1.191	0.467	1.087	1.134
3	1.826	0.717	1.668	1.134
4	1.120	0.440	1.023	1.134
5	1.739	0.683	1.588	1.134
6	1.023	0.402	0.934	1.134

Inversion Breakup Modeling Results from SCREEN3

Case	Unit Impacts, ug/m3 per g/s	Maximum One-Hour Avg Impacts, ug/m3				Distance to Maximum (m)
		NOx	SO2	CO	PM10	
1	1.008	1.9733	0.7747	1.8021	1.1431	18,754
2	1.363	1.6228	0.6371	1.4820	1.5456	15,011
3	1.146	2.0925	0.8215	1.9110	1.2996	17,066
4	1.531	1.7150	0.6733	1.5663	1.7362	13,777
5	1.346	2.3401	0.9187	2.1372	1.5264	15,155
6	1.847	1.8898	0.7419	1.7259	2.0945	11,993

Flat Terrain Modeling Results from SCREEN3

Case	Unit Impacts, ug/m3 per g/s	Maximum One-Hour Avg Impacts, ug/m3				Distance to Maximum (m)
		NOx	SO2	CO	PM10	
1	0.865	1.6931	0.6647	1.5463	0.9808	1,117
2	1.120	1.3335	0.5235	1.2178	1.2701	1,143
3	0.996	1.8177	0.7136	1.6600	1.1289	1,073
4	1.390	1.5571	0.6113	1.4221	1.5763	1,070
5	1.224	2.1280	0.8354	1.9435	1.3880	1,113
6	1.908	1.9522	0.7664	1.7829	2.1637	971

Adjust unit impacts for longer averaging periods to account for 90-minute duration of fumigation

Case	1-hr unit	3-hr unit	8-hr unit	24-hr unit
1	1.008	0.936	0.892	0.874
2	1.363	1.242	1.166	1.135
3	1.146	1.071	1.024	1.005
4	1.531	1.461	1.416	1.399
5	1.346	1.285	1.247	1.232
6	1.908	1.908	1.908	1.908

Table 5.1B-6R (cont'd)

Case/Avg Period	NOx	SO2	CO	PM10
One-Hour				
1	1.97	0.77	1.80	-
2	1.62	0.64	1.48	-
3	2.09	0.82	1.91	-
4	1.72	0.67	1.57	-
5	**2.34**	**0.92**	**2.14**	-
6	1.95	0.77	1.78	-
3 Hours				
1	-	0.65	-	-
2	-	0.52	-	-
3	-	0.69	-	-
4	-	0.58	-	-
5	-	**0.79**	-	-
6	-	0.69	-	-
8 Hours				
1	-	-	1.12	-
2	-	-	0.89	-
3	-	-	1.19	-
4	-	-	1.01	-
5	-	-	**1.39**	-
6	-	-	1.25	-
24 Hours				
1	-	0.27	-	0.40
2	-	0.21	-	0.51
3	-	0.29	-	0.46
4	-	0.25	-	0.63
5	-	**0.34**	-	0.56
6	-	0.31	-	**0.87**

NOTES TO TABLE 5.1B-6R

INVERSION BREAKUP FUMIGATION ANALYSIS

Inversion breakup fumigation is generally a short-term phenomenon and was evaluated here as persisting for up to 90 minutes. SCREEN3 was used to model 1-hour unit impacts from the CTG/HRSG under 2.5 m/s winds and F stability (for fumigation impacts) and under all meteorological conditions (shown in the table as "Inversion Breakup Modeling Results from SCREEN3").

For longer-term averaging periods, impacts were calculated using the highest modeled impact from SCREEN3 for the corresponding averaging period. A sample calculation for 24-hour average PM_{10} for Case 1 is as follows:

- For Case 1, 1-hour average unit impact under inversion breakup conditions = 1.008 μg/m^3 per g/s.
- For Case 1, max. 1-hour average unit impact from SCREEN3 = 0.865 μg/m^3 per g/s.
- The appropriate unit impact for the 24-hour averaging period is calculated as 1.5 hours of inversion breakup fumigation plus 22.5 hours of operation under typical conditions (from SCREEN3): [(1.5 * 1.008 μg/m^3 per g/s) + (22.5 * 0.865 μg/m^3 per g/s)] ÷ 24 hrs = 0.874 μg/m^3 per g/s.
- For an emission rate of 1.134 g/s, the total 24-hour average PM_{10} impact under inversion breakup fumigation conditions is: 0.874 μg/m^3 per g/s * 1.134 g/s * 0.4 [persistence factor for converting 1-hour average screening impact into 24-hour average concentration] = 0.40 μg/m$^{3.}$

Table 5.1B-7aR
NCPA Lodi Energy Center
Emission Rates and Stack Parameters for Modeling Commissioning Impacts
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

	Stack Diam, m	Stack Height, m	Exh Temp, Deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Em Rates, g/s	
						NOx	CO
Gas Turbine/HRSG (Case 2)	6.706	45.720	349.111	376.597	10.664	50.40	252.00
Auxiliary Boiler	0.762	19.812	421.889	5.101	11.186	3.87E-02	0.17

Table 5.1B-7bR
NCPA Lodi Energy Center
Detailed Emission Calculations for Turbine Commissioning
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

Commissioning Test	Activity	Days	Daily Operation (hrs/day)	GT Firing Rate (MMBtu/hr)	Pollutant	Emission Factor (lbs/MMBtu)	Hourly Emissions (lbs/hr)	Daily Emissions (lbs/day)	Total Emissions During Test (lbs)
FSNL + Ign. Tests	FSNL Operation	2	8	400	NOx		125	1,000.0	2,000.0
					CO		900	7,200.0	14,400.0
					VOC		16.0	128.0	256.0
					SOx	0.0028	1.14	9.1	18.2
					PM10		9.0	72.0	144.0
Steam Blows	Part Load Operation	3	10	1,303	NOx		400	4,000.0	12,000.0
					CO		2000	20,000.0	60,000.0
					VOC		16	160.0	480.0
					SOx	0.0028	3.7	37.1	111.2
					PM10		9.0	90.0	270.0
Part Load Tests	Part Load Operation	4	12	1,303	NOx	0.1088	141.71	1,700.6	6,802.3
					CO		385	4,620.0	18,480.0
					VOC		16.0	192.0	768.0
					SOx	0.0028	3.7	44.5	177.9
					PM10		9.0	108.0	432.0
Full Load Tests without SCR operational	Full Load Operation	4	12	2,142	NOx	0.0326	69.9	839.2	3,356.7
					CO	0.0066	14.2	170.3	681.1
					VOC	0.0018	3.8	45.5	182.0
					SOx	0.0028	6.1	73.1	292.5
					PM10		9.0	108.0	432.0
Multiple Load Tests with SCR at partial control	Startup/Shutdown	5	3	2,142	NOx		100.0	684.8	3,424.0
					CO		900.0	2827.7	14,138.5
					VOC		16.0	82.1	410.7
					SOx	0.0028	6.1	73.1	365.6
					PM10		9.0	108.0	540.0
	Full Load Operation		9		NOx	0.0200	42.8	inc	inc
					CO	0.0066	14.2	inc	inc
					VOC	0.0018	3.8	inc	inc
					SOx	0.0028	6.1	inc	inc
					PM10		9.0	inc	inc
Performance Tests with SCR at full control	Startup/Shutdown	10	3	2,142	NOx		100.0	439.8	4,398.3
					CO		900.0	2827.7	28,277.0
					VOC		16.0	82.1	821.3
					SOx	0.0028	6.1	73.1	731.2
					PM10		9.0	108.0	1,080.0
	Full Load Operation		9	2,142	NOx	0.0073	15.5	inc	inc
					CO	0.0066	14.2	inc	inc
					VOC	0.0018	3.8	inc	inc
					SOx	0.0028	6.1	inc	inc
					PM10		9.0	inc	inc

Total Commissioning Hours: 292

Table 5.1-7bR (cont'd)

Notes:

1. Emission factors during FSNL and ignition tests
   NOx - based on max expected hourly emission rate of 125 lbs/hr.
   CO - based on startup emission rate of 900 lbs/hr.
   VOC, SOx and PM10 - based on startup emission rates and 1.0 grain S/100 dscf n.g.
2. Emission factors during steam blows
   NOx - based on max expected hourly emission rate of 400 lbs/hr.
   CO - based on maximum expected hourly emission rate of 2000 lbs/hr.
   VOC, SOx and PM10 - based on startup emission rates and 1.0 grain S/100 dscf n.g.
3. Emission factors during part load tests
   NOx - based on estimate for part load test tuning combustor (ppm @ 15% O2) = 30
   CO - based on hourly emission rate used for Crockett Cogeneration plant commissioning period.
   VOC, SOx and PM10 - based on startup emission rates and 1.0 grain S/100 dscf n.g.
4. Emission factors during full load tests without SCR operational
   NOx level in ppmvd @ 15% O_2 = 9
   CO, VOC - based on combustor operating in pre-mix mode (3 ppmc CO and 1.4 ppmc for VOC).
   SOx and PM10 - emission factors based on fuel flow and 1.0 grain S/100 dscf n.g.
5. Emission factors during full load tests with SCR partially operational
   NOx - based information with combustor operating in pre-mix mode and SCR controlling NOx to 5.5 ppmc.
   CO, VOC - based on combustor operating in pre-mix mode (3 ppmc CO, 1.4 ppmc for VOC).
   SOx and PM10 - emission factors based on fuel flow and 1.0 grain S/100 dscf n.g.
6. Emission factors during full load tests with SCR fully operational
   NOx - based on combustor operating in pre-mix mode and SCR operational (2 ppmc NOx).
   CO, VOC - based on combustor operating in pre-mix mode and ox cat operational, 3 hours of startups
   (3 ppmc CO, 1.4 ppmc for VOC for 9 hours; 900 lb/hr for CO and 16 lb/hr for VOC during startups).
   SOx and PM10 - emission factors based on fuel flow and 1.0 grain S/100 dscf n.g.
7. Startup and shutdown emission rates unchanged.

Table 5.1B-7cR
NCPA Lodi Energy Center
Emissions During Commissioning
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

Unit	Maximum Hourly and Daily Emissions									
	Peak Hour Emissions					Peak Day Emissions				
	NOx	CO	VOC	SOx	PM10	NOx	CO	VOC	SOx	PM10
	(lbs/hr)					(lbs/day)				
One Gas Turbine in Steam Blow	400.0	2,000.0	16.0	6.1	9.0	4,000	20,000	192.0	73.1	108
Aux. Boiler	0.3	1.34	0.2	0.10	0.28	7.4	32.1	3.7	2.5	6.7
Total	400.3	2,001.3	16.2	6.2	9.3	4,007	20,032	196	76	115

Unit	Total Commissioning Emissions				
	NOx	CO	VOC	SOx	PM10
	(lbs)				
Gas Turbine/HRSG	31,981	135,977	2,918	1,697	2,898
Aux. Boiler (based on 60 hrs)	18	80	9	6	17
Total	32,000	136,057	2,927	1,703	2,915

FIGURE 5.1B-1A JANUARY PREDOMINANT MEAN CIRCULATION OF THE SURFACE WINDS

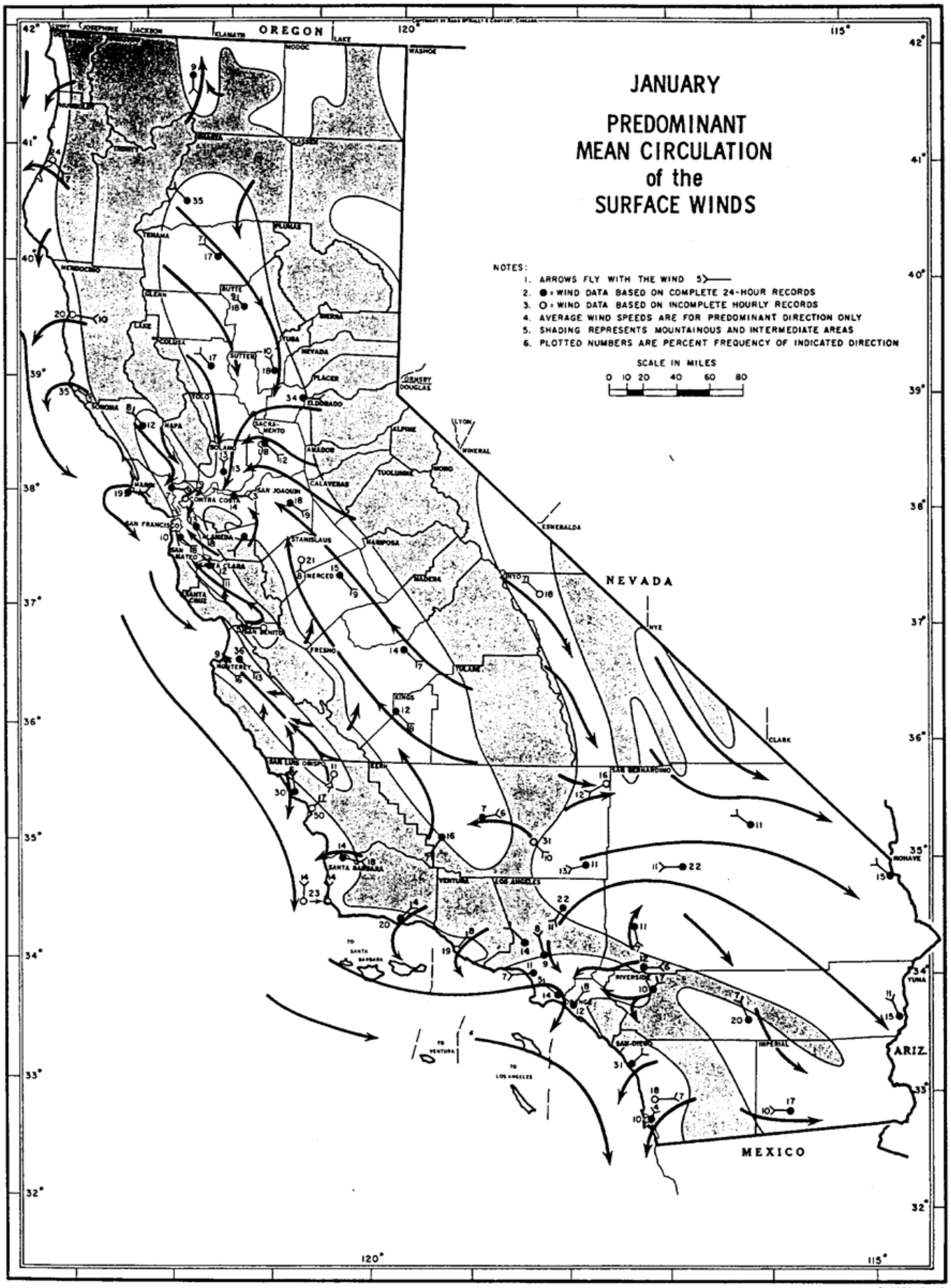


FIGURE 5.1B-1B APRIL PREDOMINANT MEAN CIRCULATION OF THE SURFACE WINDS

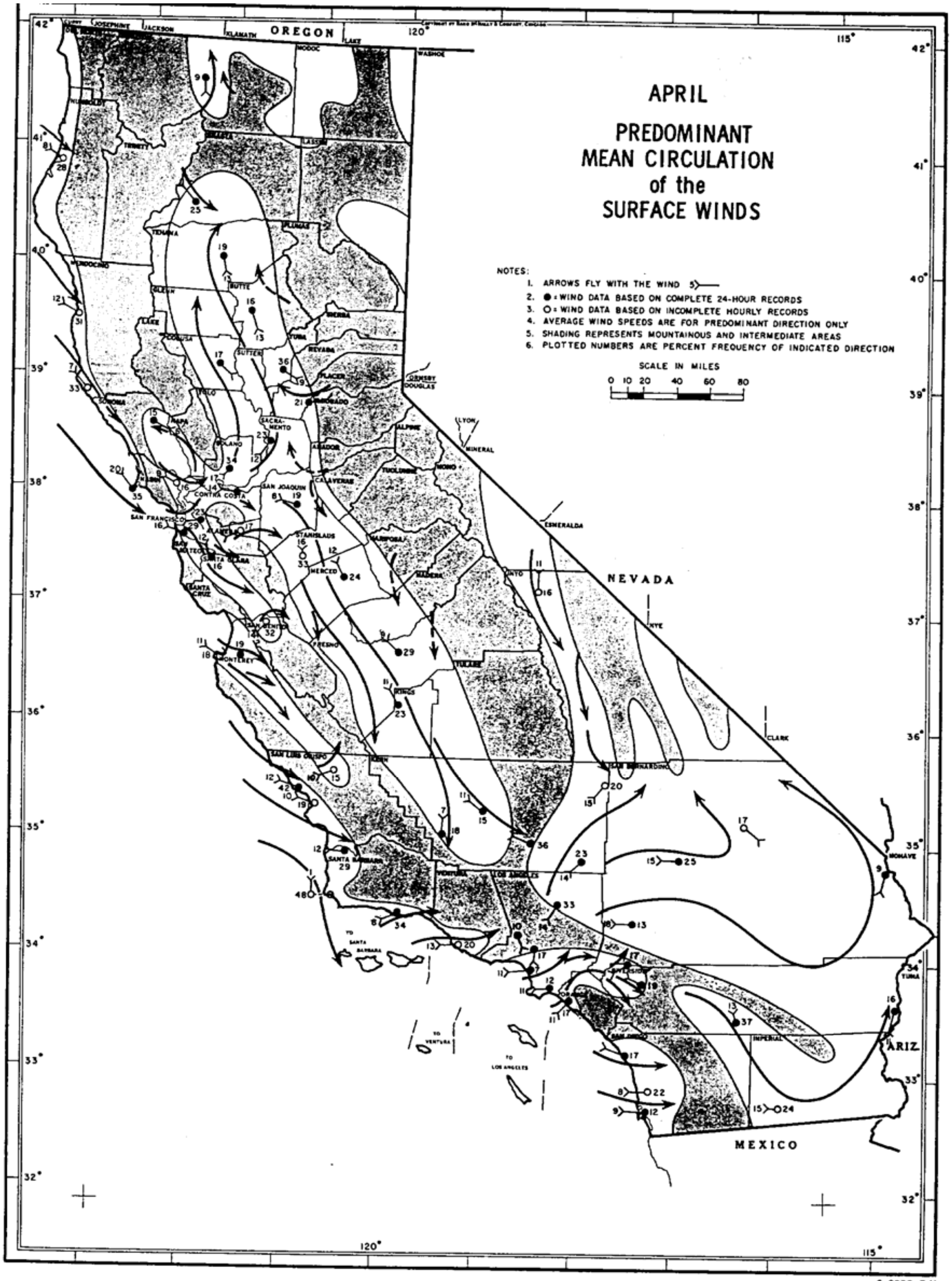


FIGURE 5.1B-1C JULY PREDOMINANT CIRCULATION OF THE SURFACE WINDS

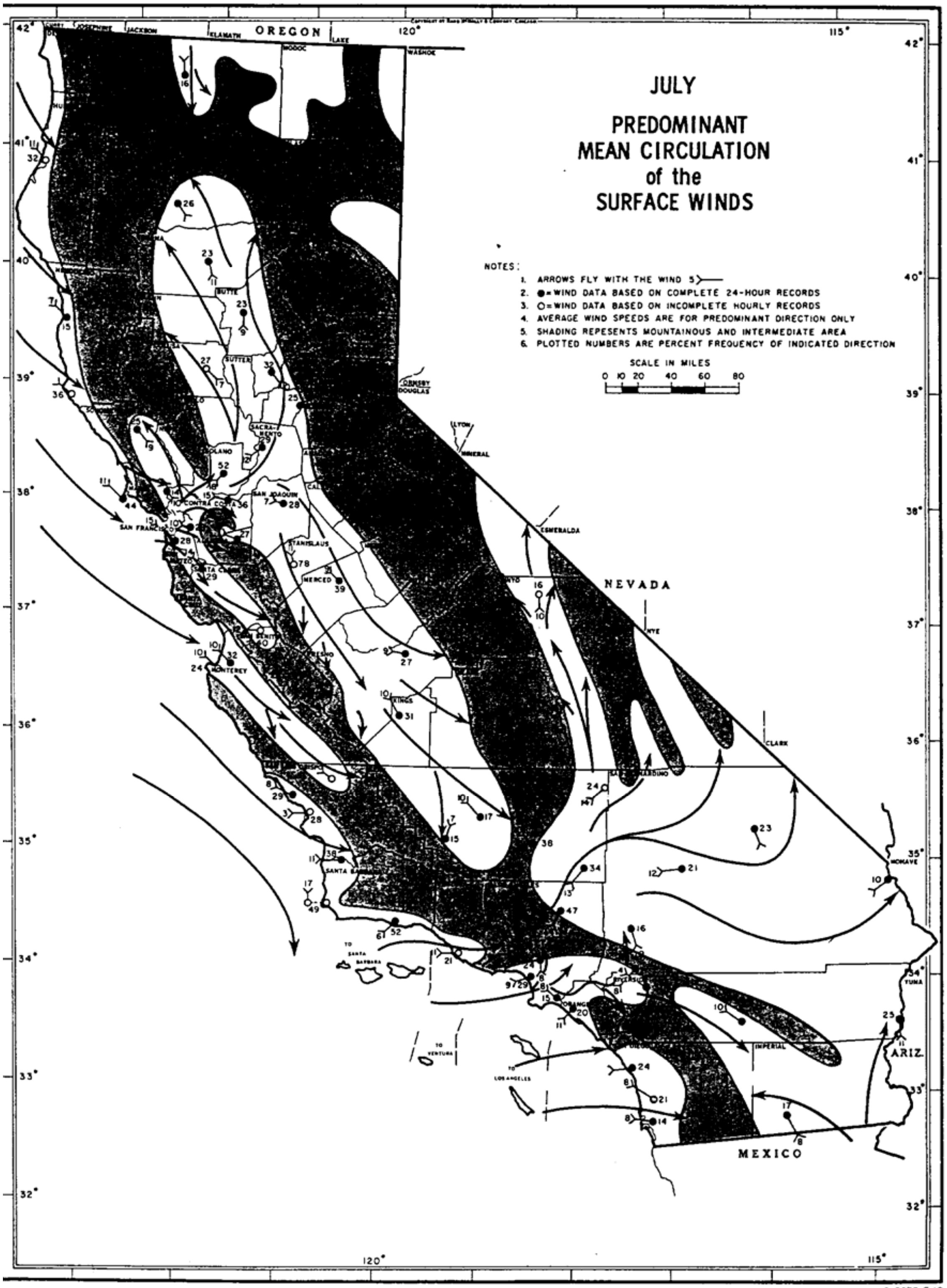


FIGURE 5.1B-1D OCTOBER PREDOMINANT MEAN CIRCULATION OF THE SURFACE WINDS

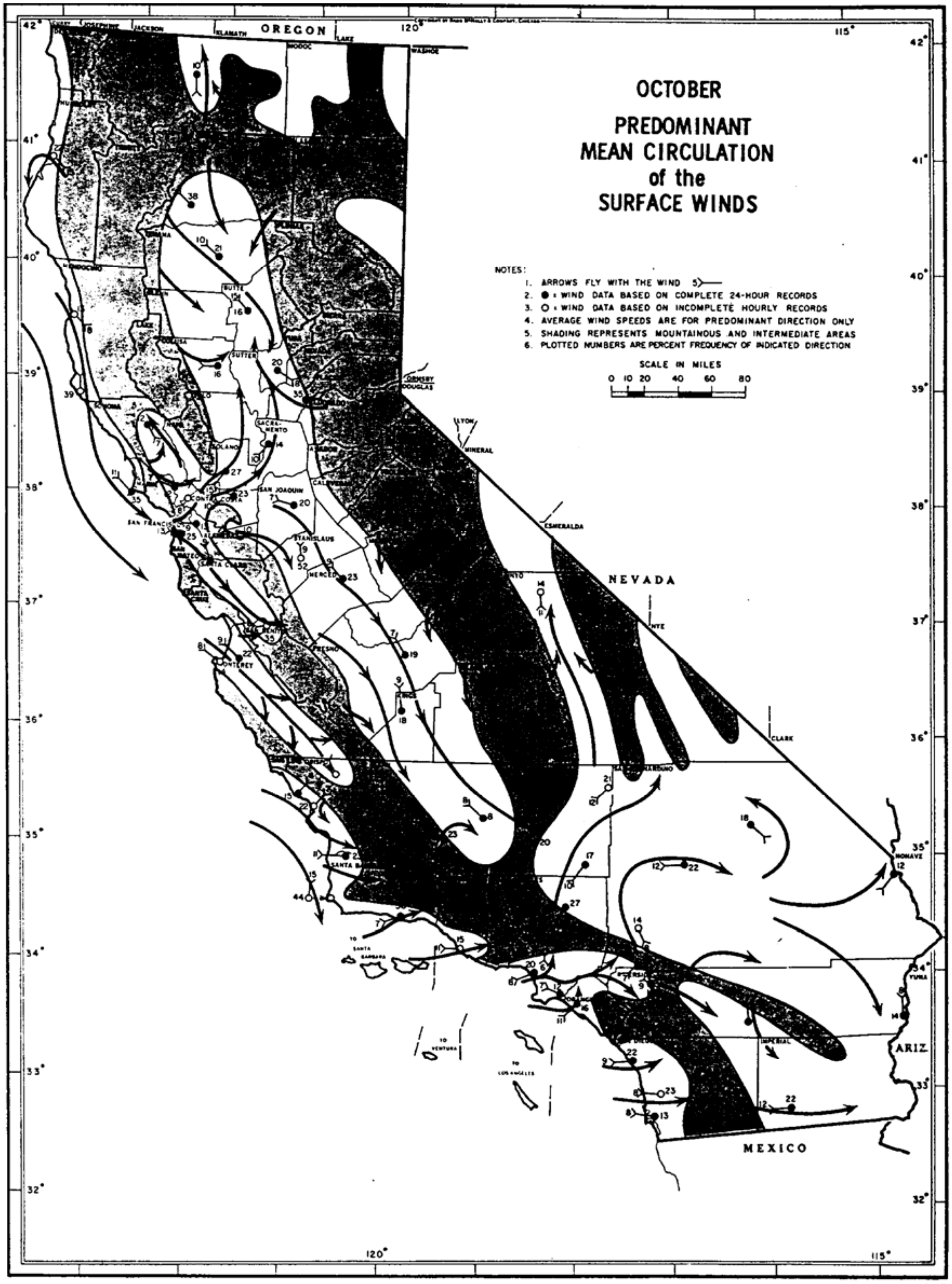
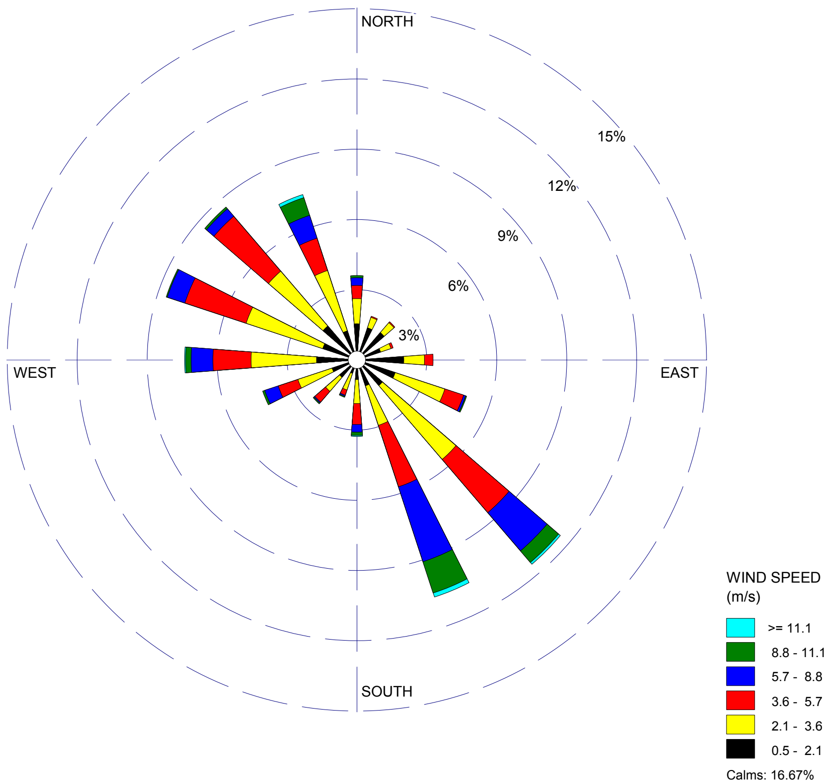


Figure 8.1B-2A 2000 1st Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:	DISPLAY:
Stockton, CA - First Quarter, 2000 **January 1, 2000 through March 31, 2000**	**Wind Speed** **Direction (blowing from)**



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2000 **Jan 1 - Mar 31** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **16.67%**	TOTAL COUNT: **2142 hrs.**	
	AVG. WIND SPEED: **3.29 m/s**	DATE: **5/1/2008**	PROJECT NO.:

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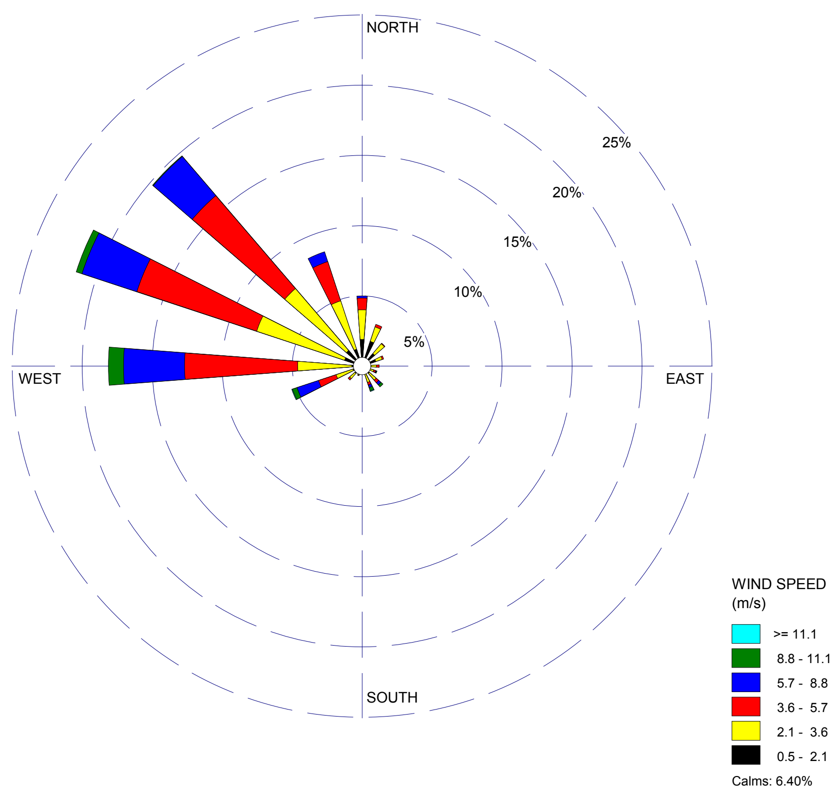
Figure 8.1B-2B 2000 2nd Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:	DISPLAY:
Stockton, CA - Second Quarter, 2000 **April 1, 2000 through June 30, 2000**	**Wind Speed** **Direction (blowing from)**



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2000 **Apr 1 - Jun 30** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **6.40%**	TOTAL COUNT: **2046 hrs.**	
	AVG. WIND SPEED: **4.00 m/s**	DATE: **5/1/2008**	PROJECT NO.:

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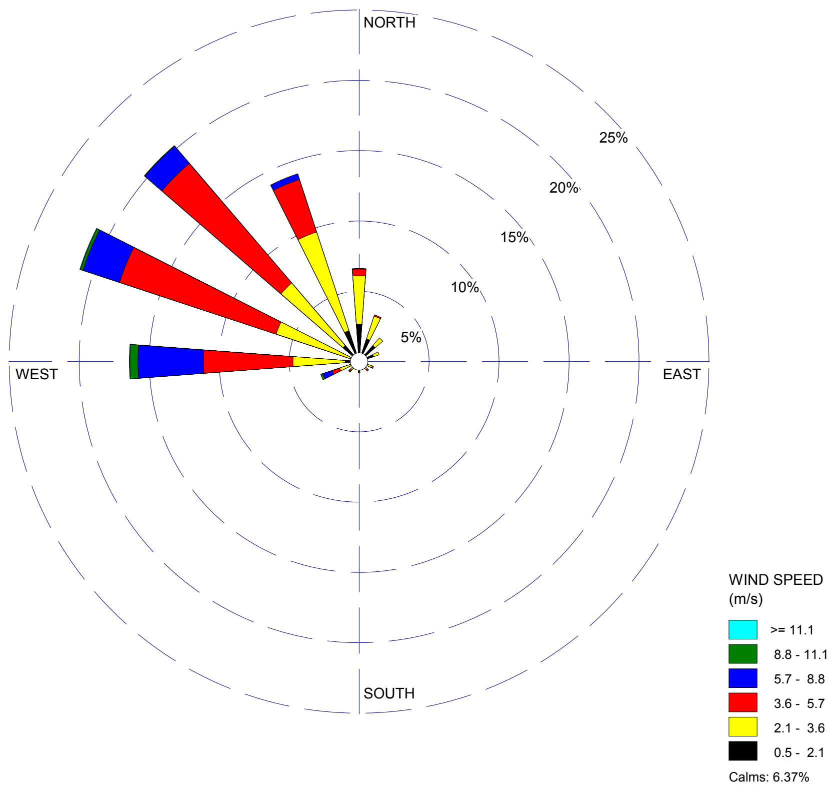
Figure 8.1B-2C 2000 3rd Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:	DISPLAY:
Stockton, CA - Third Quarter, 2000 **July 1, 2000 through September 30, 2000**	**Wind Speed** **Direction (blowing from)**



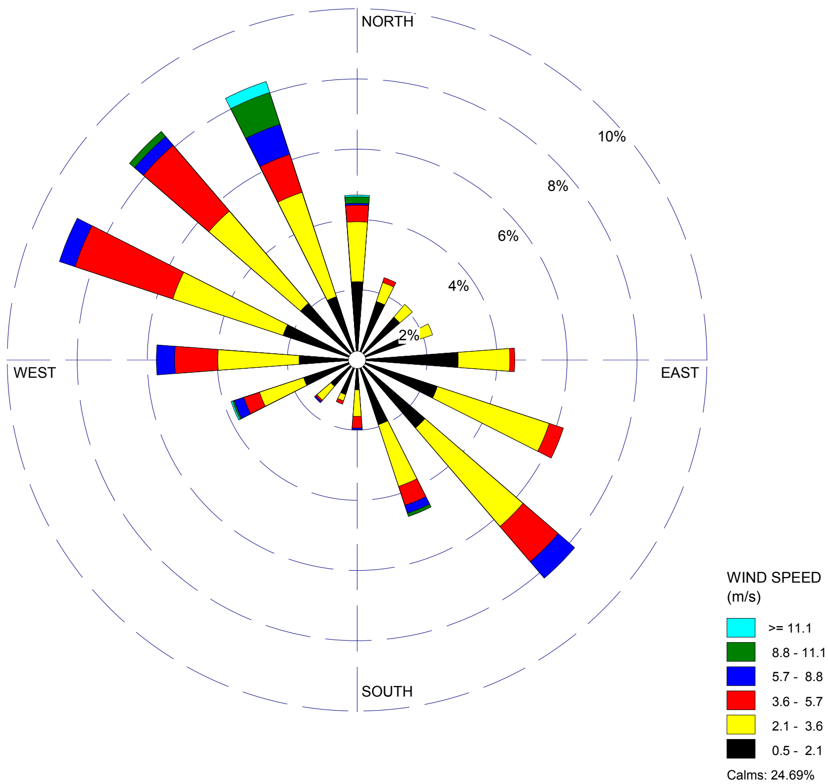
COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2000 **Jul 1 - Sep 30** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **6.37%**	TOTAL COUNT: **2118 hrs.**	
	AVG. WIND SPEED: **3.72 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 8.1B-2D 2000 4th Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:
Stockton, CA - Fourth Quarter, 2000
October 1, 2000 through December 31, 2000

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2000 **Oct 1 - Dec 31** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **24.69%**	TOTAL COUNT: **2114 hrs.**	
	AVG. WIND SPEED: **2.36 m/s**	DATE: **5/1/2008**	PROJECT NO.:

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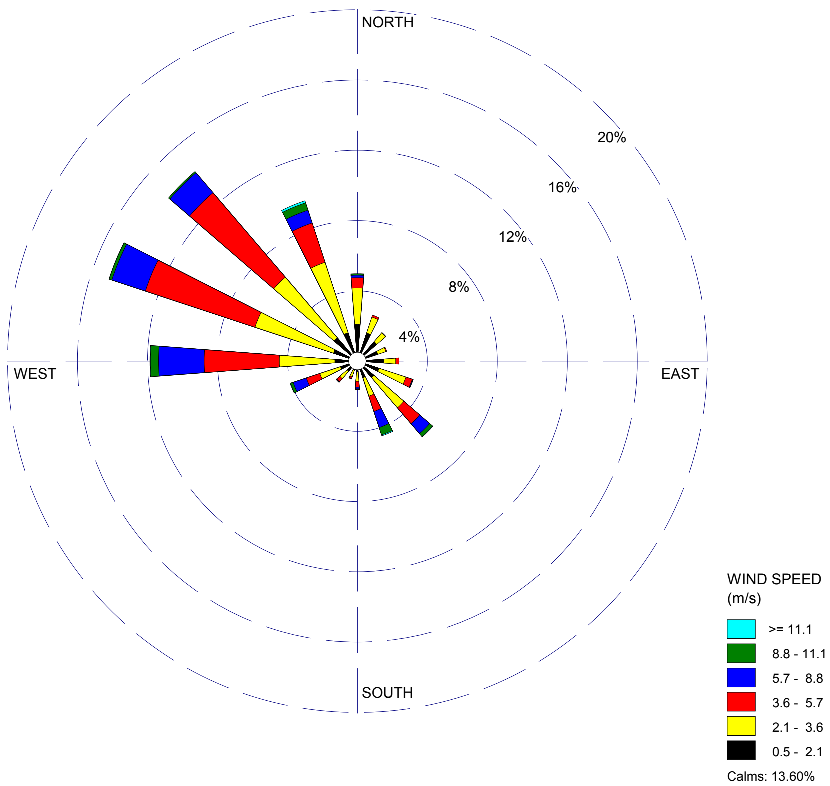
Figure 8.1B-2E 2000 Annual Wind Rose, Stockton, CA

WIND ROSE PLOT:
Stockton, CA - 2000
January 1, 2000 through December 31, 2000

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:

DATA PERIOD:
2000
Jan 1 - Dec 31
00:00 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:
13.60%

TOTAL COUNT:
8420 hrs.

AVG. WIND SPEED:
3.34 m/s

DATE:
5/1/2008

PROJECT NO.:

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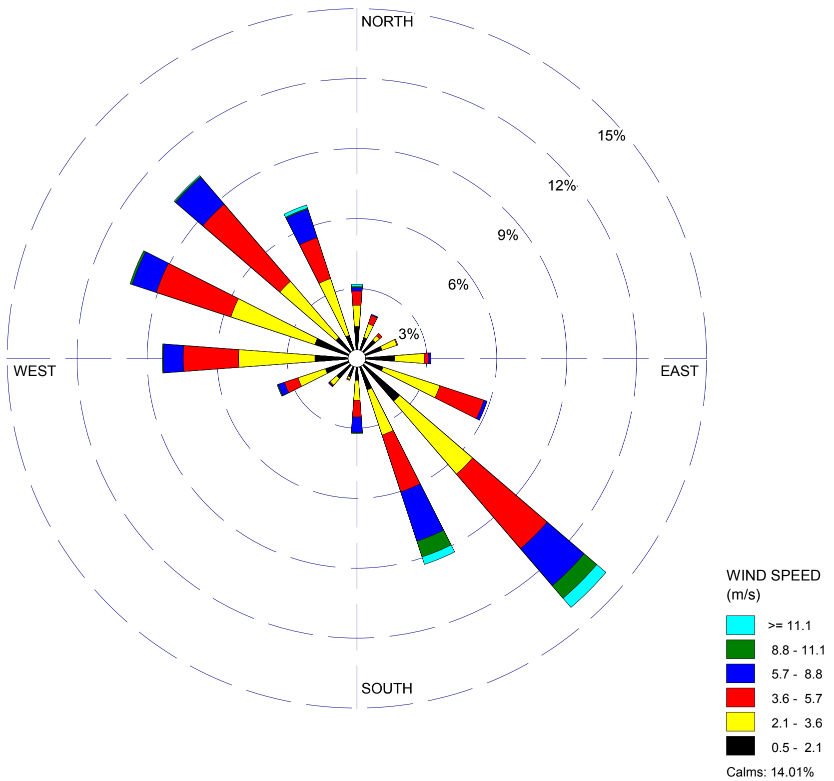
Figure 8.1B-3A 2001 1st Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:	DISPLAY:
Stockton, CA - First Quarter, 2001 **January 1, 2001 through March 31, 2001**	**Wind Speed** **Direction (blowing from)**



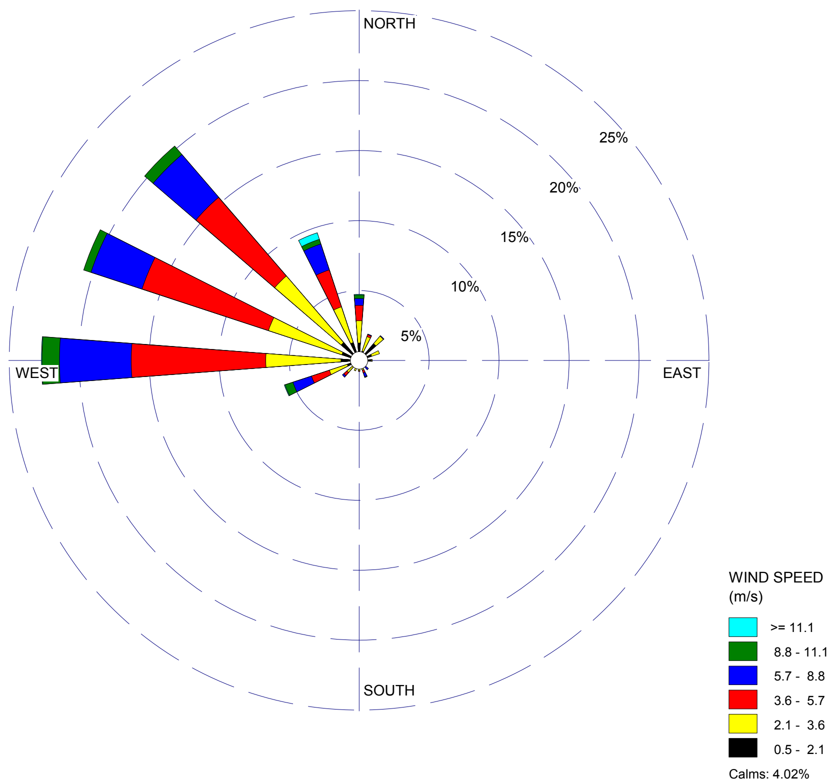
COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2001 **Jan 1 - Mar 31** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **14.01%**	TOTAL COUNT: **2113 hrs.**	
	AVG. WIND SPEED: **3.40 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 8.1B-3B 2001 2nd Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:
Stockton, CA - Second Quarter, 2001
April 1, 2001 through June 30, 2001

DISPLAY:
Wind Speed
Direction (blowing from)



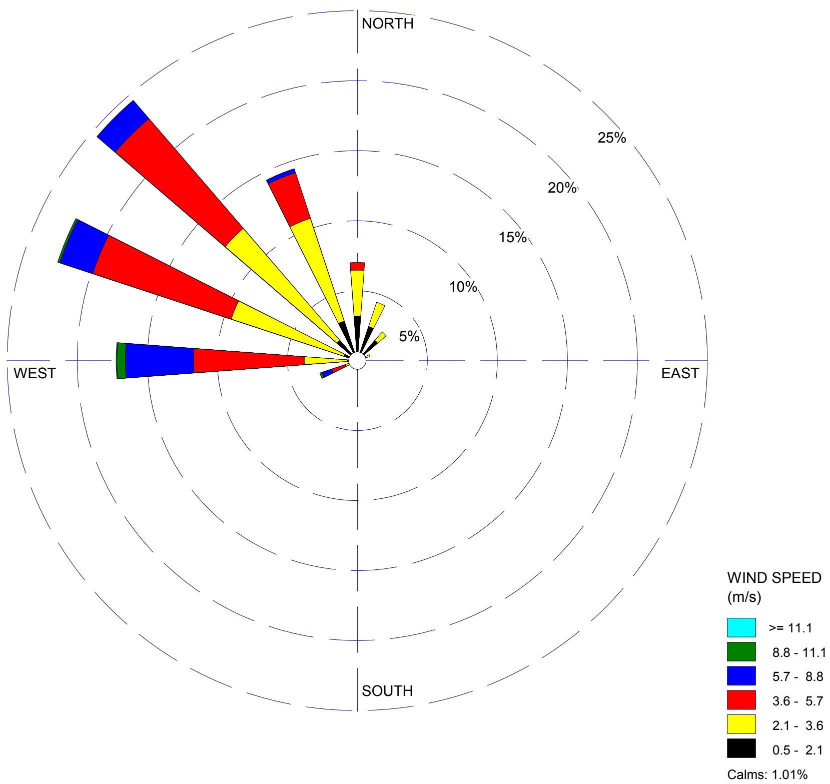
COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2001 **Apr 1 - Jun 30** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **4.02%**	TOTAL COUNT: **2013 hrs.**	
	AVG. WIND SPEED: **4.34 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 8.1B-3C 2001 3rd Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:
Stockton, CA - Third Quarter, 2001
July 1, 2001 through September 30, 2001

DISPLAY:
Wind Speed
Direction (blowing from)

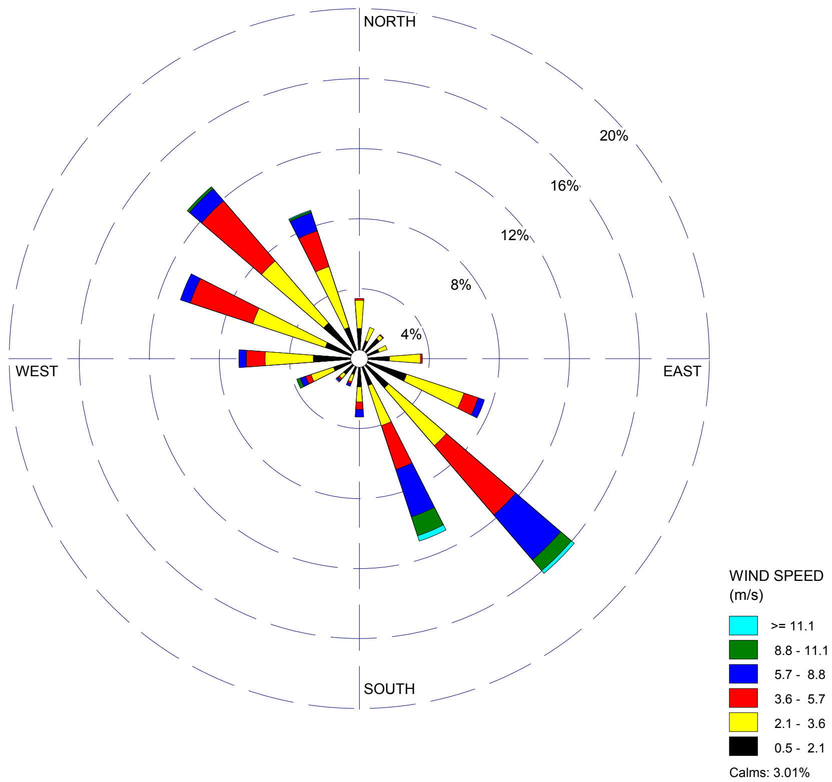


COMMENTS:	DATA PERIOD: **2001** **Jul 1 - Sep 30** **00:00 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **1.01%**	TOTAL COUNT: **1985 hrs.**	
	AVG. WIND SPEED: **3.85 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 8.1B-3D 2001 4th Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:	DISPLAY:
Stockton, CA - Fourth Quarter, 2001 **October 1, 2001 through December 31, 2001**	**Wind Speed** **Direction (blowing from)**

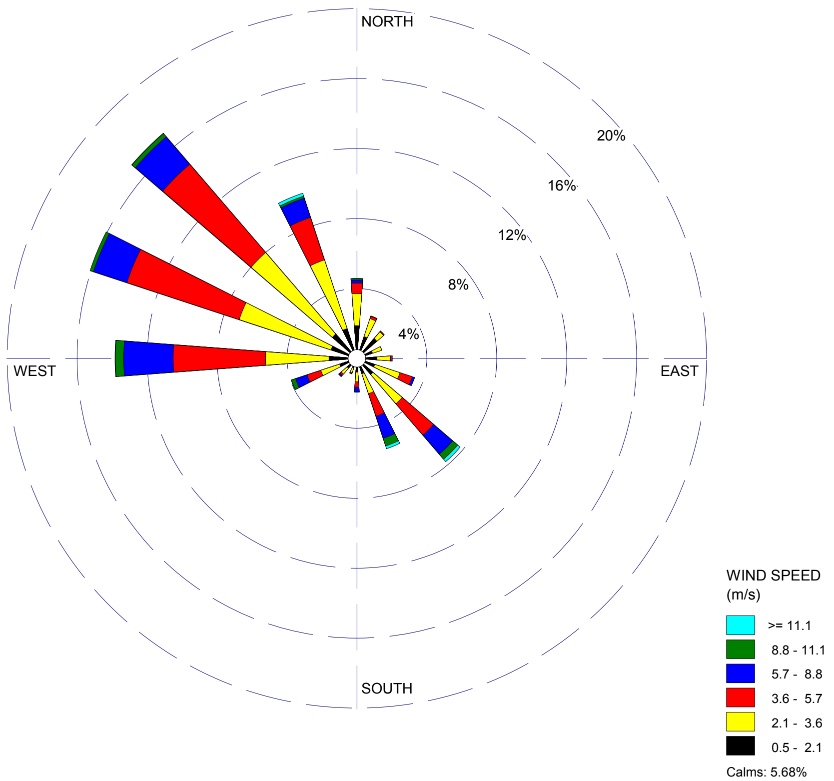


COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2001 **Oct 1 - Dec 31** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **3.01%**	TOTAL COUNT: **1863 hrs.**	
	AVG. WIND SPEED: **3.60 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 8.1B-3E 2001 Annual Wind Rose, Stockton, CA

WIND ROSE PLOT:	DISPLAY:
Stockton, CA - 2001 **January 1, 2001 through December 31, 2001**	**Wind Speed** **Direction (blowing from)**

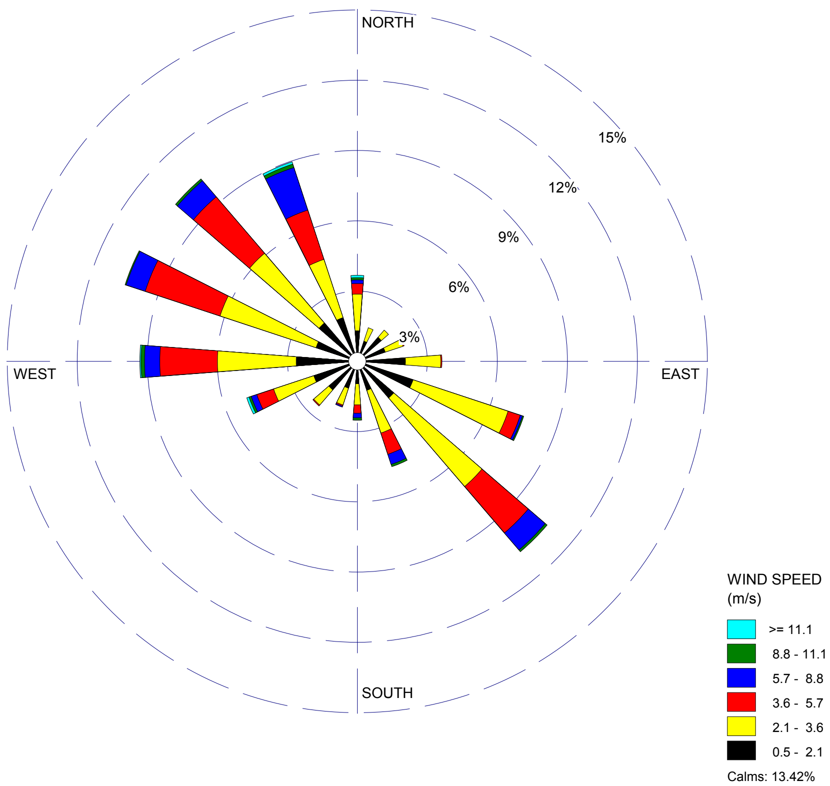


COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2001 **Jan 1 - Dec 31** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **5.68%**	TOTAL COUNT: **7974 hrs.**	
	AVG. WIND SPEED: **3.80 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 8.1B-4A 2002 1st Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:	DISPLAY:
Stockton, CA - First Quarter, 2002 **January 1, 2002 through March 31, 2002**	**Wind Speed** **Direction (blowing from)**

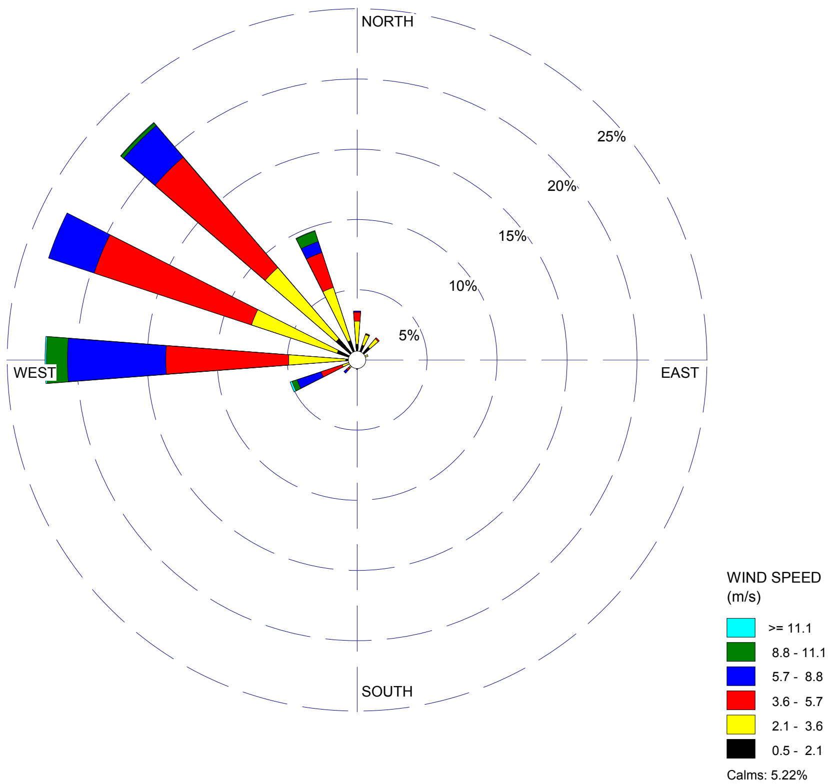


COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2002 **Jan 1 - Mar 31** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **13.42%**	TOTAL COUNT: **1990 hrs.**	
	AVG. WIND SPEED: **2.93 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 8.1B-4B 2002 2nd Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:	DISPLAY:
Stockton, CA - Second Quarter, 2002 **April 1, 2002 through June 30, 2002**	**Wind Speed** **Direction (blowing from)**

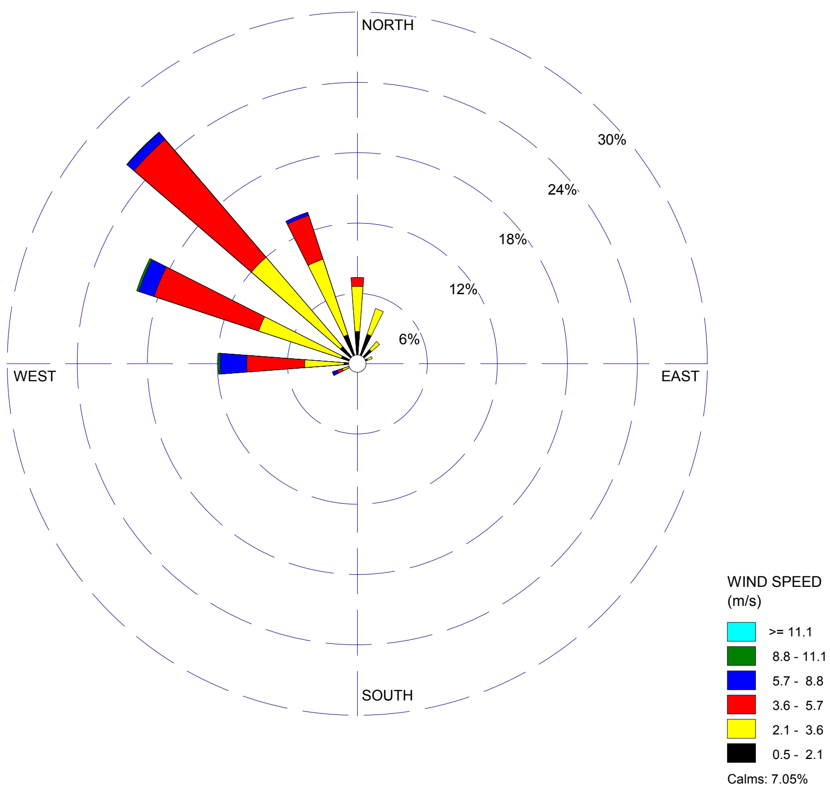


COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2002 **Apr 1 - Jun 30** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **5.22%**	TOTAL COUNT: **2068 hrs.**	
	AVG. WIND SPEED: **4.27 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 8.1B-4C 2002 3rd Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:	DISPLAY:
Stockton, CA - Third Quarter, 2002 **July 1, 2002 through September 30, 2002**	**Wind Speed** **Direction (blowing from)**



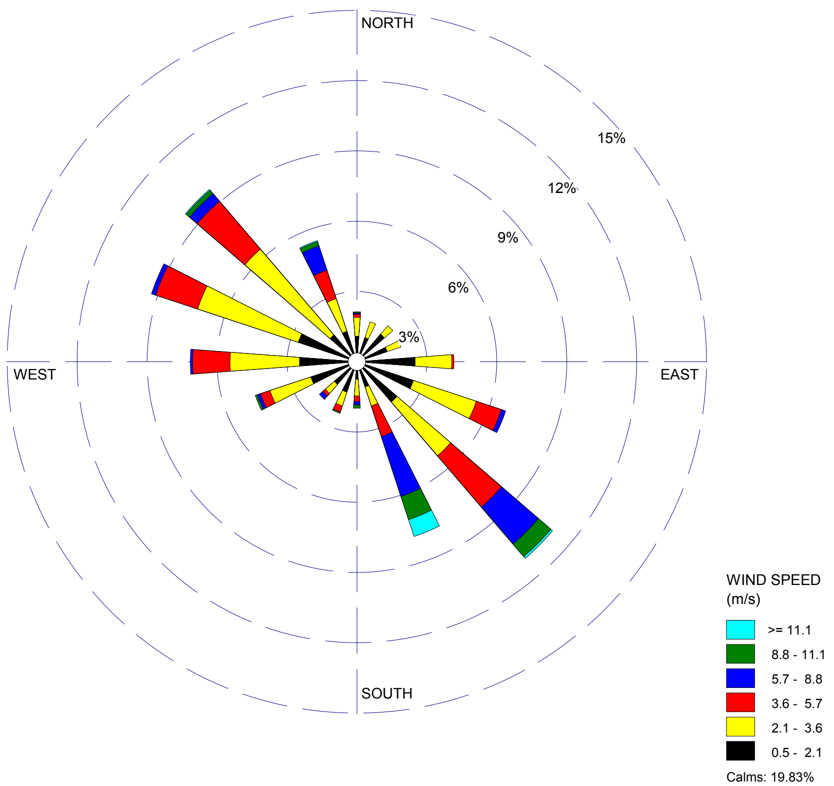
COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2002 **Jul 1 - Sep 30** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **7.05%**	TOTAL COUNT: **2084 hrs.**	
	AVG. WIND SPEED: **3.40 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 8.1B-4D 2002 4th Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:
Stockton, CA - Fourth Quarter, 2002
October 1, 2002 through December 31, 2002

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:

DATA PERIOD:
2002
Oct 1 - Dec 31
00:00 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:
19.83%

TOTAL COUNT:
2118 hrs.

AVG. WIND SPEED:
2.88 m/s

DATE:
5/1/2008

PROJECT NO.:

WRPLOT View - Lakes Environmental Software

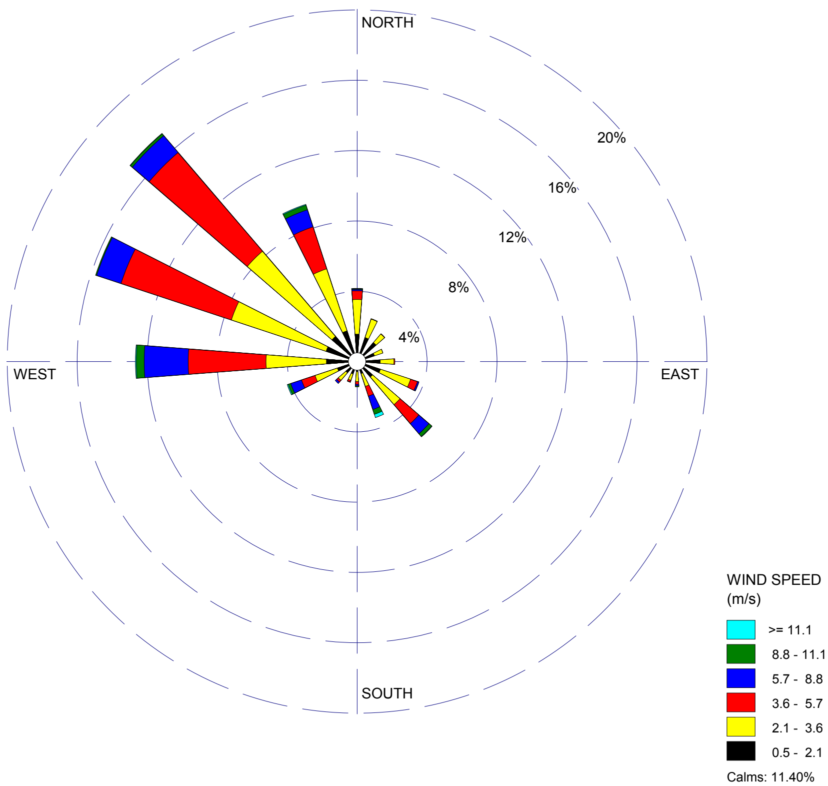
Figure 8.1B-4E 2002 Annual Wind Rose, Stockton, CA

WIND ROSE PLOT:

Stockton, CA - 2002
January 1, 2002 through December 31, 2002

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

DATA PERIOD:

2002
Jan 1 - Dec 31
00:00 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:

11.40%

TOTAL COUNT:

8260 hrs.

AVG. WIND SPEED:

3.37 m/s

DATE:

5/1/2008

PROJECT NO.:

WRPLOT View - Lakes Environmental Software

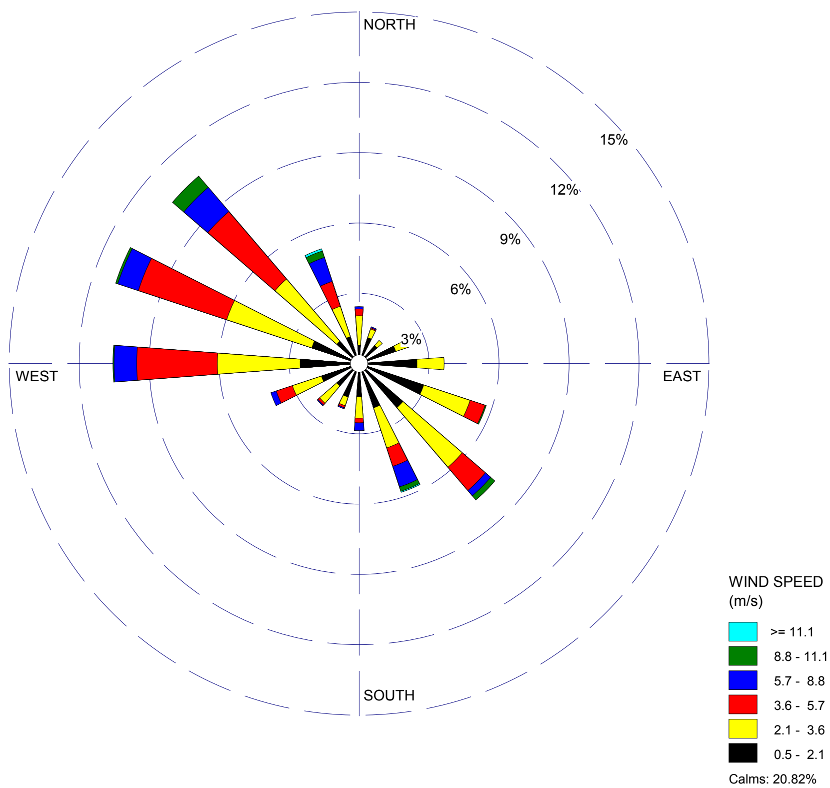
Figure 8.1B-5A 2003 1st Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:

Stockton, CA - First Quarter, 2003
January 1, 2003 through March 31, 2003

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2003 **Jan 1 - Mar 31** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **20.82%**	TOTAL COUNT: **2061 hrs.**	
	AVG. WIND SPEED: **2.70 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

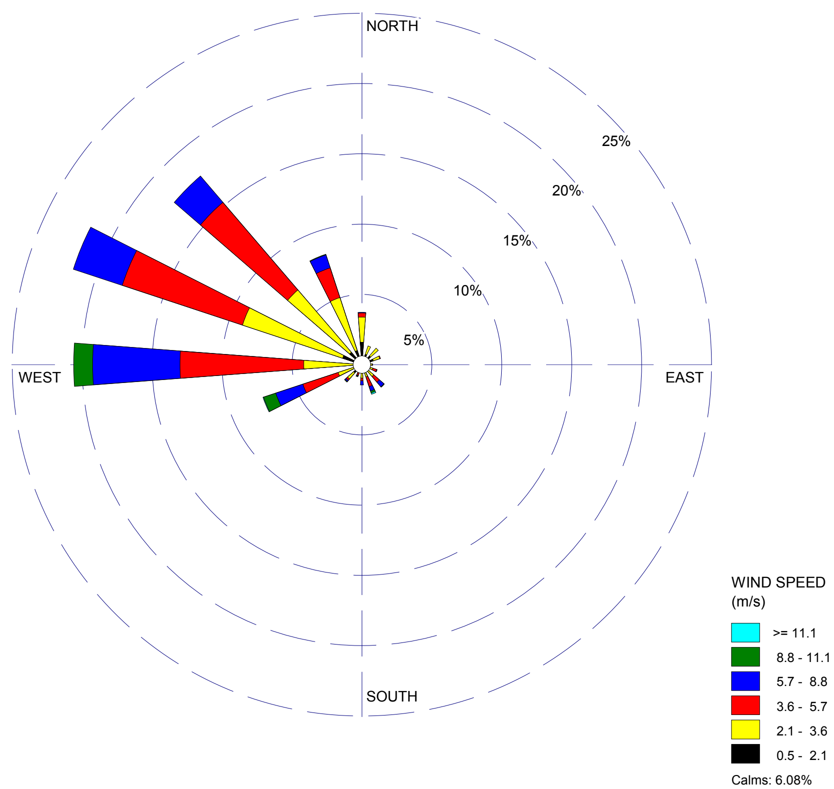
Figure 8.1B-5B 2003 2nd Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:

Stockton, CA - Second Quarter, 2003
April 1, 2003 through June 30, 2003

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD: **2003** **Apr 1 - Jun 30** **00:00 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **6.08%**	TOTAL COUNT: **2072 hrs.**	
	AVG. WIND SPEED: **4.15 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

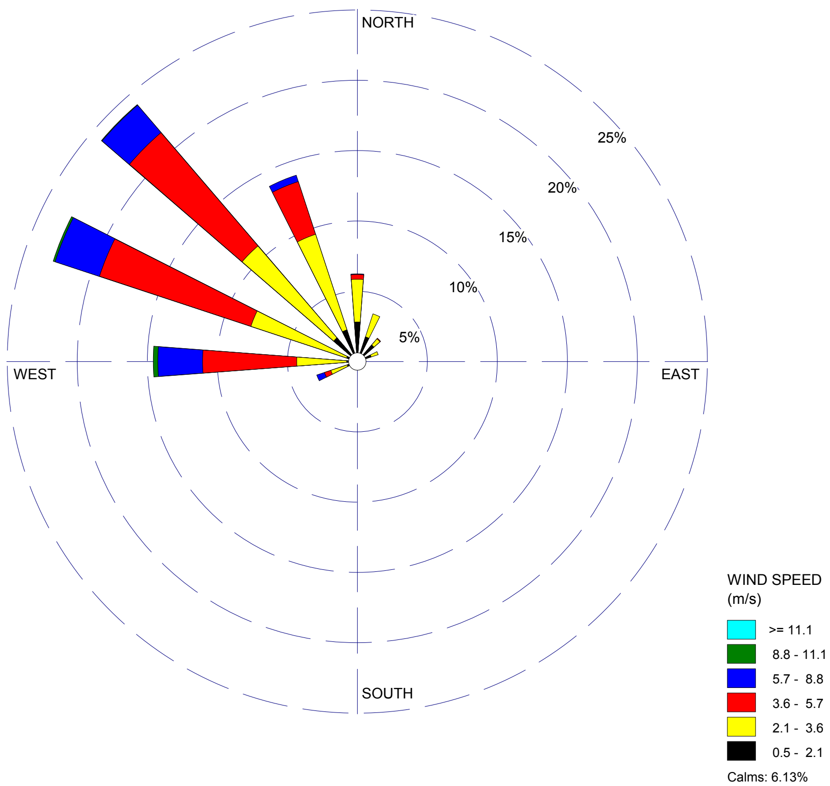
Figure 8.1B-5C 2003 3rd Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:

Stockton, CA - Third Quarter, 2003
July 1, 2003 through September 30, 2003

DISPLAY:

Wind Speed
Direction (blowing from)



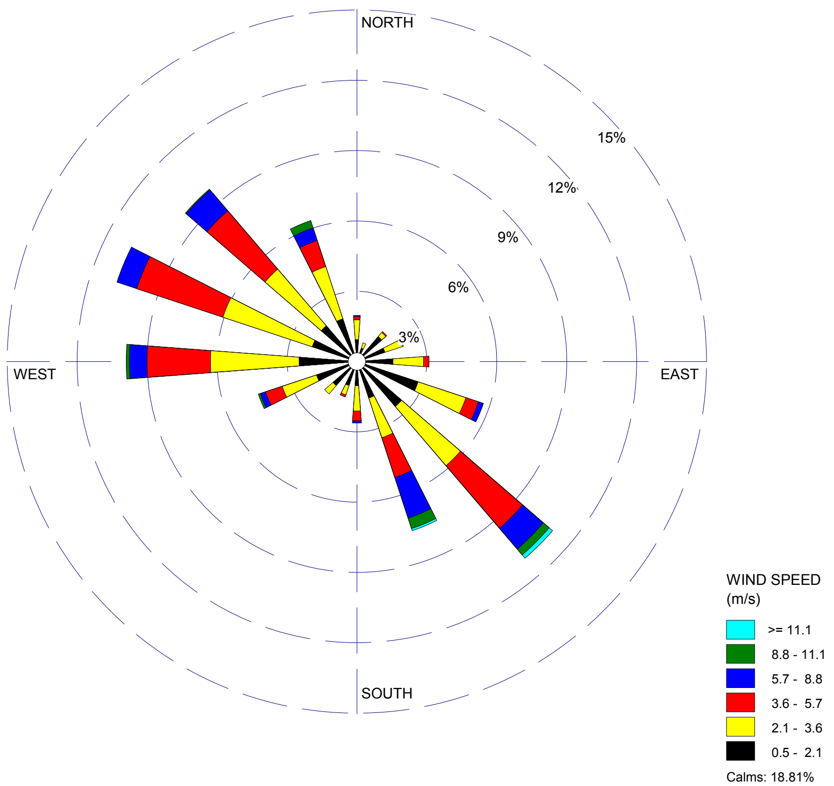
COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2003 **Jul 1 - Sep 30** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **6.13%**	TOTAL COUNT: **2104 hrs.**	
	AVG. WIND SPEED: **3.68 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 8.1B-5D 2003 4th Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:
Stockton, CA - Fourth Quarter, 2003
October 1, 2003 through December 31, 2003

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2003 **Oct 1 - Dec 31** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **18.81%**	TOTAL COUNT: **2137 hrs.**	
	AVG. WIND SPEED: **2.86 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

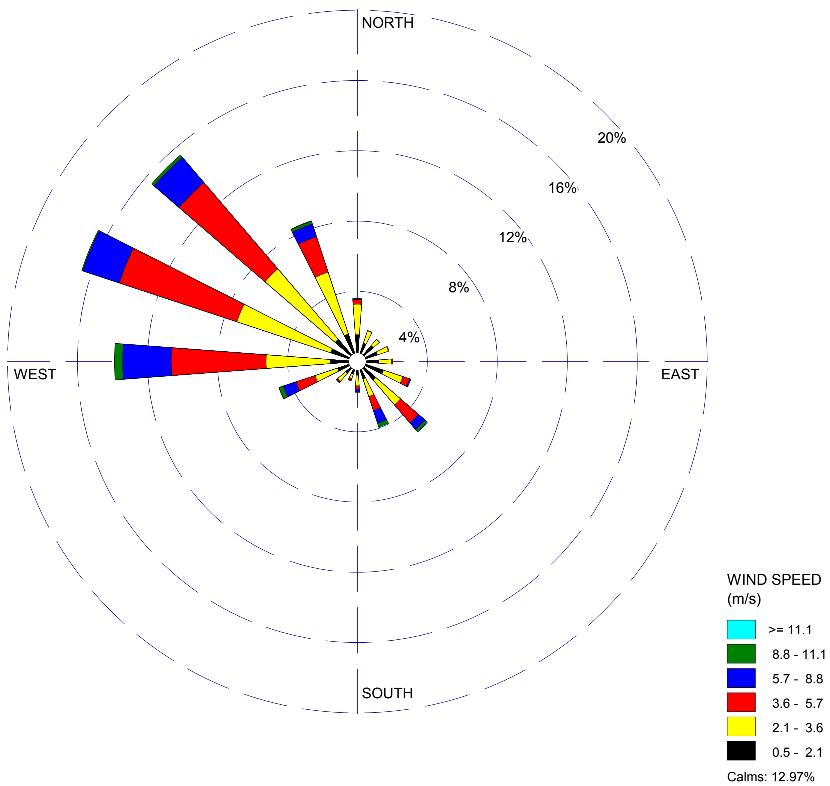
Figure 8.1B-5E 2003 Annual Wind Rose, Stockton, CA

WIND ROSE PLOT:

Stockton, CA - 2003
January 1, 2003 through December 31, 2003

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2003 **Jan 1 - Dec 31** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **12.97%**	TOTAL COUNT: **8374 hrs.**	
	AVG. WIND SPEED: **3.35 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

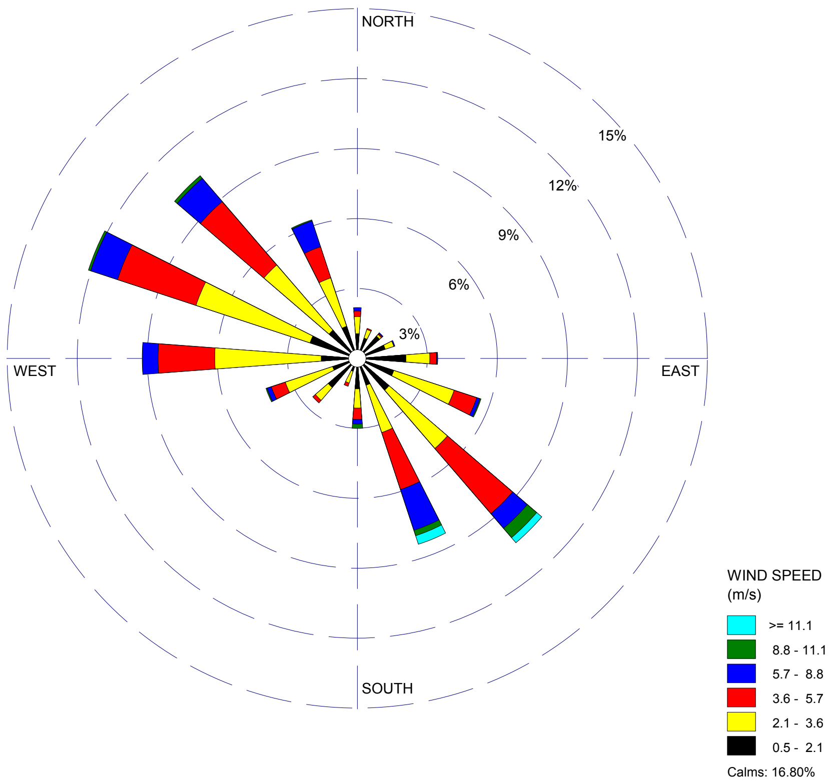
Figure 8.1B-6A 2004 1st Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:

Stockton, CA - First Quarter, 2004
January 1, 2004 through March 31, 2004

DISPLAY:

Wind Speed
Direction (blowing from)



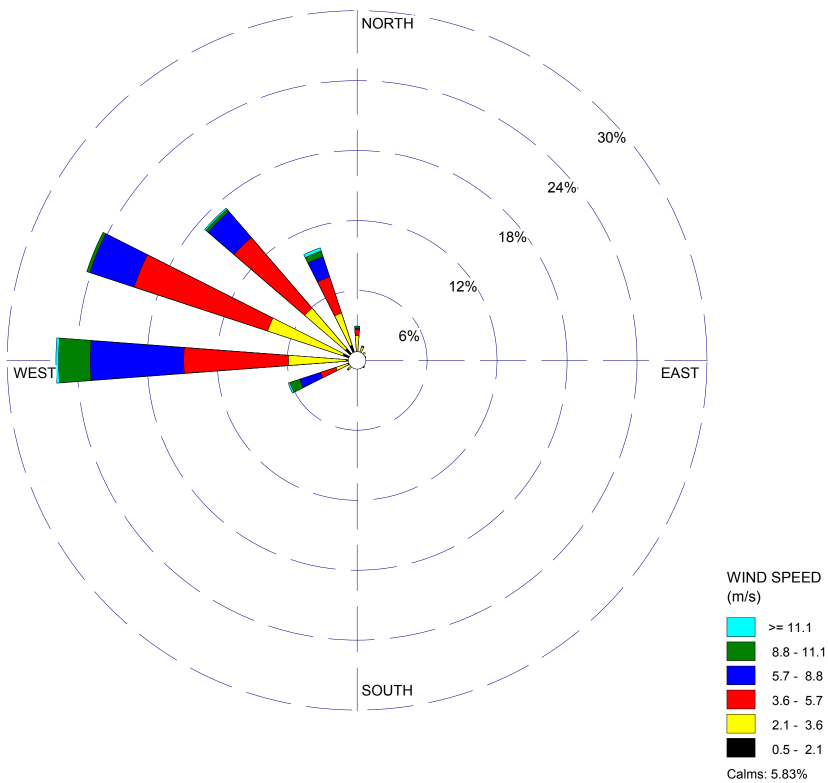
COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2004 **Jan 1 - Mar 31** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **16.80%**	TOTAL COUNT: **2066 hrs.**	
	AVG. WIND SPEED: **3.04 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 8.1B-6B 2004 2nd Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:
Stockton, CA - Second Quarter, 2004
April 1, 2004 through June 30, 2004

DISPLAY:
Wind Speed
Direction (blowing from)

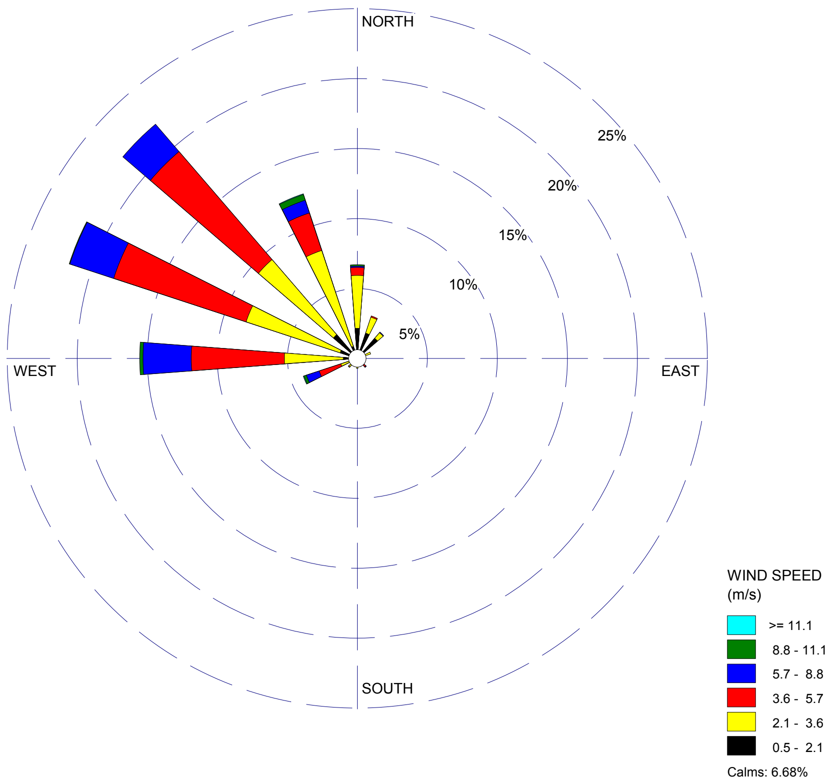


COMMENTS:	DATA PERIOD: **2004** **Apr 1 - Jun 30** **00:00 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **5.83%**	TOTAL COUNT: **2111 hrs.**	
	AVG. WIND SPEED: **4.51 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 8.1B-6C 2004 3rd Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:	DISPLAY:
Stockton, CA - Third Quarter, 2004 **July 1, 2004 through September 30, 2004**	**Wind Speed** **Direction (blowing from)**



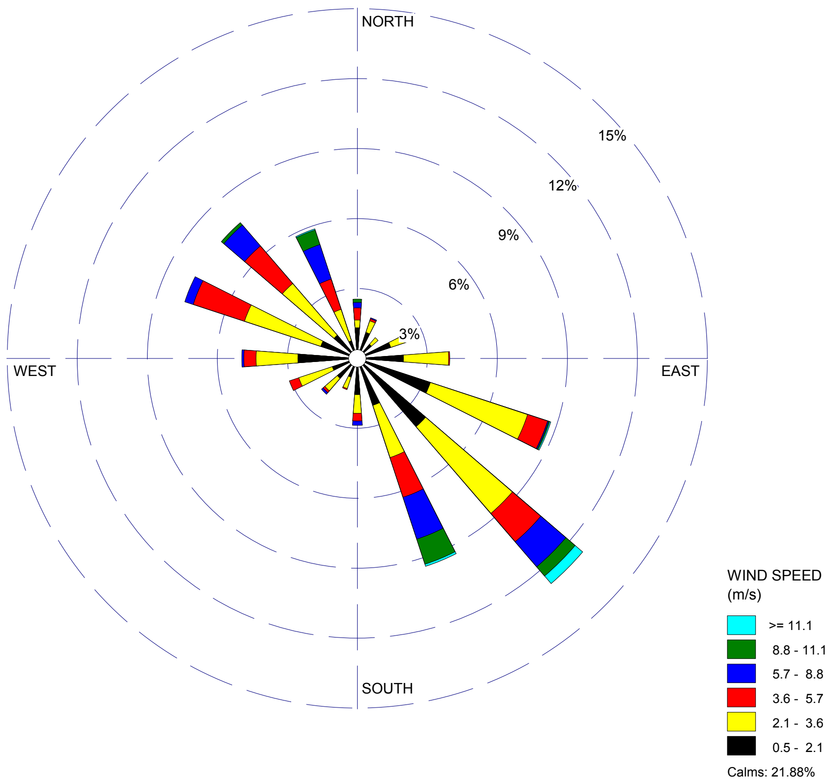
COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2004 **Jul 1 - Sep 30** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **6.68%**	TOTAL COUNT: **2096 hrs.**	
	AVG. WIND SPEED: **3.77 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

Figure 8.1B-6D 2004 4th Quarter Wind Rose, Stockton, CA

WIND ROSE PLOT:
Stockton, CA - Fourth Quarter, 2004
October 1, 2004 through December 31, 2004

DISPLAY:
Wind Speed
Direction (blowing from)



COMMENTS:

DATA PERIOD:
2004
Oct 1 - Dec 31
00:00 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:
21.88%

TOTAL COUNT:
2125 hrs.

AVG. WIND SPEED:
2.74 m/s

DATE:
5/1/2008

PROJECT NO.:

WRPLOT View - Lakes Environmental Software

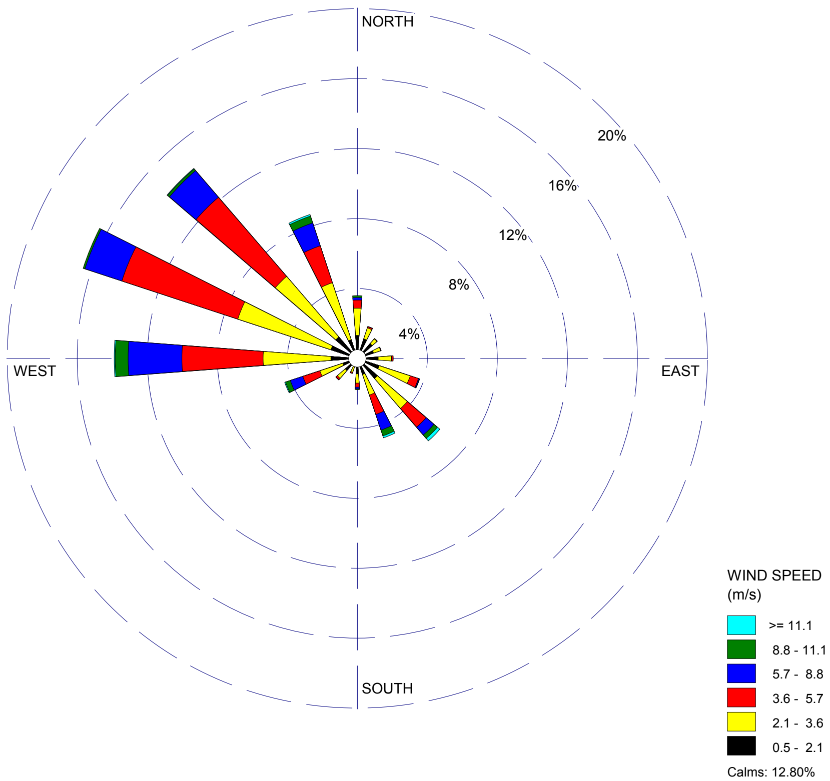
Figure 8.1B-6E 2004 Annual Wind Rose, Stockton, CA

WIND ROSE PLOT:

Stockton, CA - 2004
January 1, 2004 through December 31, 2004

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
	2004 **Jan 1 - Dec 31** **00:00 - 23:00**	MODELER:	
	CALM WINDS: **12.80%**	TOTAL COUNT: **8398 hrs.**	
	AVG. WIND SPEED: **3.52 m/s**	DATE: **5/1/2008**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

2000: ANNUAL
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	1146	81	179	89	35	14	7	3	9	1563
NNE	1	63	134	24	9	1	0	0	0	232
NE	1	68	93	17	2	0	0	0	0	181
ENE	1	50	83	10	3	1	0	0	0	148
E	4	68	82	31	11	4	0	0	0	200
ESE	0	52	124	70	23	9	2	1	2	283
SE	0	58	115	122	60	40	26	23	34	478
SSE	0	43	76	58	38	39	36	37	50	377
S	0	25	42	30	16	12	5	2	5	137
SSW	0	24	39	17	9	0	0	0	2	91
SW	0	33	60	18	14	6	3	0	1	135
WSW	0	29	101	60	37	31	29	23	30	340
W	0	47	152	176	204	157	108	85	67	996
WNW	0	50	167	301	335	219	117	40	27	1256
NW	0	47	202	281	335	198	80	38	15	1196
NNW	0	53	208	236	141	57	43	17	52	807
Sub-Total:	1153	791	1857	1540	1272	788	456	269	294	8420

Average Wind Speed: 3.34m/s

2000: FIRST QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	357	19	22	15	7	5	4	2	3	434
NNE	1	14	20	6	0	1	0	0	0	42
NE	1	18	22	4	1	0	0	0	0	46
ENE	0	10	18	5	1	1	0	0	0	35
E	3	14	33	12	7	1	0	0	0	70
ESE	0	19	40	26	14	4	1	1	1	106
SE	0	11	50	59	33	31	17	18	27	246
SSE	0	13	24	26	24	35	31	34	41	228
S	0	7	17	16	12	7	4	2	5	70
SSW	0	6	15	8	5	0	0	0	2	36
SW	0	12	20	6	10	3	1	0	1	53
WSW	0	7	32	18	12	7	7	4	4	91
W	0	11	55	31	16	19	7	9	10	158
WNW	0	19	36	52	44	15	12	3	3	184
NW	0	13	49	45	44	22	4	3	4	184
NNW	0	12	41	33	25	6	14	6	22	159
Sub-Total:	362	205	494	362	255	157	102	82	123	2142

Average Wind Speed: 3.29m/s

2000: SECOND QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	131	14	45	23	13	4	2	1	0	233
NNE	0	13	40	7	4	0	0	0	0	64
NE	0	12	24	7	1	0	0	0	0	44
ENE	1	10	19	1	2	0	0	0	0	33
E	0	8	10	3	2	2	0	0	0	25
ESE	0	2	11	5	2	1	1	0	1	23
SE	0	8	9	10	3	2	2	1	5	40
SSE	0	8	10	7	3	1	2	2	6	39
S	0	5	0	3	0	0	0	0	0	8
SSW	0	5	6	3	1	0	0	0	0	15
SW	0	4	17	3	1	2	0	0	0	27
WSW	0	4	17	19	13	14	13	11	17	108
W	0	6	30	58	91	74	52	25	34	370
WNW	0	9	42	111	98	86	59	20	14	439
NW	0	4	50	95	99	79	49	22	5	403
NNW	0	6	41	53	34	26	11	4	0	175
Sub-Total:	132	118	371	408	367	291	191	86	82	2046

Average Wind Speed: 4.00m/s

2000: THIRD QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	135	25	66	38	6	4	1	0	0	275
NNE	0	14	51	7	2	0	0	0	0	74
NE	0	16	28	3	0	0	0	0	0	47
ENE	0	13	16	3	0	0	0	0	0	32
E	0	4	6	0	0	0	0	0	0	10
ESE	0	6	15	0	1	1	0	0	0	23
SE	0	5	6	5	1	2	0	0	0	19
SSE	0	4	5	0	2	0	0	0	0	11
S	0	5	6	4	1	1	0	0	0	17
SSW	0	1	7	3	1	0	0	0	0	12
SW	0	2	11	4	2	1	1	0	0	21
WSW	0	5	18	8	7	5	6	6	6	61
W	0	8	37	55	79	56	44	45	23	347
WNW	0	4	36	92	150	99	37	16	10	444
NW	0	13	48	95	155	82	25	8	2	428
NNW	0	19	86	100	64	19	8	1	0	297
Sub-Total:	135	144	442	417	471	270	122	76	41	2118

Average Wind Speed: 3.72m/s

2000: FOURTH QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	523	23	46	13	9	1	0	0	6	621
NNE	0	22	23	4	3	0	0	0	0	52
NE	0	22	19	3	0	0	0	0	0	44
ENE	0	17	30	1	0	0	0	0	0	48
E	1	42	33	16	2	1	0	0	0	95
ESE	0	25	58	39	6	3	0	0	0	131
SE	0	34	50	48	23	5	7	4	2	173
SSE	0	18	37	25	9	3	3	1	3	99
S	0	8	19	7	3	4	1	0	0	42
SSW	0	12	11	3	2	0	0	0	0	28
SW	0	15	12	5	1	0	1	0	0	34
WSW	0	13	34	15	5	5	3	2	3	80
W	0	22	30	32	18	8	5	6	0	121
WNW	0	18	53	46	43	19	9	1	0	189
NW	0	17	55	46	37	15	2	5	4	181
NNW	0	16	40	50	18	6	10	6	30	176
Sub-Total:	524	324	550	353	179	70	41	25	48	2114

Average Wind Speed: 2.36m/s

2001: ANNUAL
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	453	62	149	84	35	13	7	4	11	818
NNE	0	43	117	31	7	4	2	0	0	204
NE	1	57	90	12	3	1	1	0	0	165
ENE	2	39	66	12	0	1	0	0	0	120
E	0	53	66	35	5	1	2	0	0	162
ESE	0	39	93	75	40	19	5	5	1	277
SE	0	41	122	110	105	83	51	46	62	620
SSE	0	33	72	64	60	48	41	43	72	433
S	0	32	53	21	14	11	11	6	6	154
SSW	0	21	40	8	3	0	2	1	0	75
SW	0	31	47	16	4	5	4	2	1	110
WSW	0	32	98	43	32	34	19	32	25	315
W	0	56	153	207	232	188	114	94	57	1101
WNW	0	49	187	328	346	192	93	53	30	1278
NW	0	57	224	355	317	213	106	47	32	1351
NNW	0	53	211	208	120	83	50	32	34	791
Sub-Total:	456	698	1788	1609	1323	896	508	365	331	7974

Average Wind Speed: 3.8 m/s

2001: FIRST QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	296	13	23	12	7	6	2	1	3	363
NNE	0	9	19	5	6	2	1	0	0	42
NE	1	11	14	1	2	1	0	0	0	30
ENE	1	12	21	4	0	1	0	0	0	39
E	0	21	25	15	3	1	2	0	0	67
ESE	0	12	34	33	32	10	1	1	1	124
SE	0	22	62	54	49	40	20	19	31	297
SSE	0	10	33	30	26	28	16	21	32	196
S	0	7	22	9	7	8	8	3	4	68
SSW	0	9	11	0	1	0	0	0	0	21
SW	0	11	16	5	0	1	1	0	0	34
WSW	0	13	32	11	8	5	2	3	2	76
W	0	12	49	46	28	22	7	9	3	176
WNW	0	17	51	52	50	21	11	10	4	216
NW	0	13	34	45	61	31	11	17	6	218
NNW	0	8	30	38	23	16	14	10	7	146
Sub-Total:	298	200	476	360	303	193	96	94	93	2113

Average Wind Speed: 3.4 m/s

2001: SECOND QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	81	14	23	20	18	4	5	3	8	176
NNE	0	5	23	8	1	2	1	0	0	40
NE	0	15	25	6	0	0	1	0	0	47
ENE	1	11	15	4	0	0	0	0	0	31
E	0	11	7	1	0	0	0	0	0	19
ESE	0	1	6	0	0	0	0	1	0	8
SE	0	2	2	6	1	0	2	5	0	18
SSE	0	4	7	4	0	4	3	3	1	26
S	0	5	8	2	1	0	0	0	0	16
SSW	0	5	7	4	0	0	0	0	0	16
SW	0	5	10	8	3	3	3	0	0	32
WSW	0	3	26	16	13	14	9	17	15	113
W	0	9	44	81	100	93	52	41	36	456
WNW	0	10	42	85	120	71	46	23	19	416
NW	0	10	57	93	82	67	49	25	23	406
NNW	0	12	31	38	28	28	19	15	22	193
Sub-Total:	82	122	333	376	367	286	190	133	124	2013

Average Wind Speed: 4.3 m/s

2001: THIRD QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	20	19	75	34	9	2	0	0	0	159
NNE	0	21	53	13	0	0	0	0	0	87
NE	0	14	36	4	0	0	0	0	0	54
ENE	0	6	11	2	0	0	0	0	0	19
E	0	6	3	0	0	0	0	0	0	9
ESE	0	0	4	0	1	0	0	0	0	5
SE	0	0	3	0	1	0	0	0	0	4
SSE	0	1	4	1	1	0	0	0	0	7
S	0	2	3	2	1	0	0	0	0	8
SSW	0	0	6	1	0	0	0	0	0	7
SW	0	2	7	2	0	0	0	0	0	11
WSW	0	2	10	6	7	13	5	9	4	56
W	0	7	19	49	90	67	49	42	18	341
WNW	0	6	53	129	127	79	29	17	6	446
NW	0	14	75	158	124	81	32	2	0	486
NNW	0	20	100	92	41	27	6	0	0	286
Sub-Total:	20	120	462	493	402	269	121	70	28	1985

Average Wind Speed: 3.85 m/s

2001: FOURTH QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	56	16	28	18	1	1	0	0	0	120
NNE	0	8	22	5	0	0	0	0	0	35
NE	0	17	15	1	1	0	0	0	0	34
ENE	0	10	19	2	0	0	0	0	0	31
E	0	15	31	19	2	0	0	0	0	67
ESE	0	26	49	42	7	9	4	3	0	140
SE	0	17	55	50	54	43	29	22	31	301
SSE	0	18	28	29	33	16	22	19	39	204
S	0	18	20	8	5	3	3	3	2	62
SSW	0	7	16	3	2	0	2	1	0	31
SW	0	13	14	1	1	1	0	2	1	33
WSW	0	14	30	10	4	2	3	3	4	70
W	0	28	41	31	14	6	6	2	0	128
WNW	0	16	41	62	49	21	7	3	1	200
NW	0	20	58	59	50	34	14	3	3	241
NNW	0	13	50	40	28	12	11	7	5	166
Sub-Total:	56	256	517	380	251	148	101	68	86	1863

Average Wind Speed: 3.6 m/s

2002: ANNUAL
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	942	58	148	85	34	7	2	2	7	1285
NNE	1	53	119	37	1	0	0	0	1	212
NE	1	61	92	17	2	0	0	0	0	173
ENE	0	44	72	12	1	0	0	0	0	129
E	0	62	80	32	4	0	0	0	0	178
ESE	0	45	131	89	25	10	5	0	2	307
SE	0	38	134	95	52	65	37	22	23	466
SSE	0	31	59	33	19	29	37	18	51	277
S	0	24	42	28	7	6	1	3	8	119
SSW	0	23	52	18	7	1	1	0	1	103
SW	0	44	47	26	7	3	5	3	1	136
WSW	0	40	105	64	39	28	24	25	22	347
W	0	63	172	194	198	169	104	79	65	1044
WNW	0	75	198	351	349	198	87	28	11	1297
NW	0	56	253	374	392	218	75	24	19	1411
NNW	0	55	194	209	123	84	44	31	36	776
Sub-Total:	944	772	1898	1664	1260	818	422	235	247	8260

Average Wind Speed: 3.37 m/s

2002: FIRST QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	267	16	29	12	8	1	1	1	5	340
NNE	0	8	17	5	0	0	0	0	0	30
NE	0	17	18	0	0	0	0	0	0	35
ENE	0	12	25	4	1	0	0	0	0	42
E	0	19	38	14	1	0	0	0	0	72
ESE	0	16	64	55	9	2	2	0	1	149
SE	0	12	72	56	27	25	11	5	5	213
SSE	0	13	33	18	11	8	6	2	3	94
S	0	10	16	11	4	3	1	2	3	50
SSW	0	7	22	10	1	0	1	0	0	41
SW	0	21	21	7	1	0	0	0	0	50
WSW	0	14	37	24	11	4	2	3	4	99
W	0	19	64	36	31	18	6	6	5	185
WNW	0	17	44	62	46	21	12	5	1	208
NW	0	12	59	50	46	17	13	4	3	204
NNW	0	17	40	34	23	21	22	14	7	178
Sub-Total:	267	230	599	398	220	120	77	42	37	1990

Average Wind Speed: 2.93 m/s

2002: SECOND QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	108	8	33	16	8	5	1	0	1	180
NNE	0	8	27	4	1	0	0	0	1	41
NE	0	11	25	5	2	0	0	0	0	43
ENE	0	7	9	1	0	0	0	0	0	17
E	0	5	3	0	1	0	0	0	0	9
ESE	0	3	3	1	0	0	0	0	0	7
SE	0	3	3	2	1	2	0	0	0	11
SSE	0	2	4	4	0	0	0	0	0	10
S	0	3	5	5	1	0	0	0	0	14
SSW	0	1	5	0	1	0	0	0	0	7
SW	0	2	6	8	3	2	3	2	0	26
WSW	0	2	8	13	18	15	18	16	14	104
W	0	5	25	71	84	97	66	60	52	460
WNW	0	14	43	107	153	91	51	17	3	479
NW	0	14	62	103	114	100	46	14	7	460
NNW	0	8	46	58	31	23	7	9	18	200
Sub-Total:	108	96	307	398	418	335	192	118	96	2068

Average Wind Speed: 4.27 m/s

2002: THIRD QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	147	24	67	46	15	1	0	0	0	300
NNE	0	26	55	22	0	0	0	0	0	103
NE	0	13	32	7	0	0	0	0	0	52
ENE	0	10	15	3	0	0	0	0	0	28
E	0	6	3	0	0	0	0	0	0	9
ESE	0	4	4	1	0	0	0	0	0	9
SE	0	2	3	2	1	0	0	0	0	8
SSE	0	3	2	2	0	0	0	0	0	7
S	0	3	9	1	0	0	0	0	0	13
SSW	0	3	3	0	0	0	0	0	0	6
SW	0	4	6	4	0	1	0	0	0	15
WSW	0	2	16	10	5	5	2	5	2	47
W	0	13	31	50	62	41	31	12	8	248
WNW	0	14	49	122	121	75	22	4	7	414
NW	0	15	80	154	184	92	14	1	2	542
NNW	0	19	80	96	50	32	5	1	0	283
Sub-Total:	147	161	455	520	438	247	74	23	19	2084

Average Wind Speed: 3.4 m/s

2002: FOURTH QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	420	10	19	11	3	0	0	1	1	465
NNE	1	11	20	6	0	0	0	0	0	38
NE	1	20	17	5	0	0	0	0	0	43
ENE	0	15	23	4	0	0	0	0	0	42
E	0	32	36	18	2	0	0	0	0	88
ESE	0	22	60	32	16	8	3	0	1	142
SE	0	21	56	35	23	38	26	17	18	234
SSE	0	13	20	9	8	21	31	16	48	166
S	0	8	12	11	2	3	0	1	5	42
SSW	0	12	22	8	5	1	0	0	1	49
SW	0	17	14	7	3	0	2	1	1	45
WSW	0	22	44	17	5	4	2	1	2	97
W	0	26	52	37	21	13	1	1	0	151
WNW	0	30	62	60	29	11	2	2	0	196
NW	0	15	52	67	48	9	2	5	7	205
NNW	0	11	28	21	19	8	10	7	11	115
Sub-Total:	422	285	537	348	184	116	79	52	95	2118

Average Wind Speed: 2.88 m/s

2003: ANNUAL
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	1086	60	138	75	18	4	2	3	0	1386
NNE	0	29	104	21	1	0	1	0	0	156
NE	3	53	66	17	2	0	0	0	0	141
ENE	0	54	79	24	3	0	0	0	0	160
E	0	48	77	38	4	2	0	0	0	169
ESE	0	61	108	60	22	11	5	1	1	269
SE	0	55	112	105	72	41	21	16	20	442
SSE	0	39	96	40	36	34	39	21	27	332
S	0	39	51	25	14	3	5	3	7	147
SSW	0	34	41	10	6	3	1	1	1	97
SW	0	38	57	28	5	1	0	2	2	133
WSW	0	43	104	66	55	41	26	25	35	395
W	0	61	156	219	234	219	123	88	60	1160
WNW	0	51	189	366	377	214	134	41	14	1386
NW	0	53	211	318	298	243	96	50	27	1296
NNW	0	53	182	213	111	66	32	19	29	705
Sub-Total:	1089	771	1771	1625	1258	882	485	270	223	8374

Average Wind Speed: 3.35 m/s

2003: FIRST QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	429	10	21	11	5	1	1	1	0	479
NNE	0	6	23	3	1	0	1	0	0	34
NE	2	13	8	4	0	0	0	0	0	27
ENE	0	18	27	7	1	0	0	0	0	53
E	0	26	36	13	0	0	0	0	0	75
ESE	0	32	46	25	13	1	0	0	1	118
SE	0	23	50	47	20	7	4	2	5	158
SSE	0	17	52	9	10	7	13	5	6	119
S	0	18	20	10	4	0	2	1	4	59
SSW	0	15	22	2	1	1	1	0	0	42
SW	0	12	23	11	2	0	0	1	0	49
WSW	0	13	35	14	12	3	3	2	0	82
W	0	24	54	47	42	29	12	7	2	217
WNW	0	14	56	53	59	23	12	6	3	226
NW	0	12	42	44	47	31	14	12	15	217
NNW	0	14	19	20	10	13	10	6	14	106
Sub-Total:	431	267	534	320	227	116	73	43	50	2061

Average Wind Speed: 2.7 m/s

2003: SECOND QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	126	15	34	21	5	1	0	1	0	203
NNE	0	3	24	2	0	0	0	0	0	29
NE	0	9	17	6	0	0	0	0	0	32
ENE	0	10	15	3	1	0	0	0	0	29
E	0	5	6	4	0	1	0	0	0	16
ESE	0	5	6	6	3	3	1	0	0	24
SE	0	5	6	12	5	6	4	5	1	44
SSE	0	2	10	7	10	5	5	2	5	46
S	0	8	8	4	2	2	3	1	2	30
SSW	0	6	1	5	3	2	0	1	1	19
SW	0	8	11	9	2	1	0	1	2	34
WSW	0	5	13	19	26	29	12	21	29	154
W	0	6	25	55	87	96	74	46	37	426
WNW	0	7	48	131	106	81	55	19	2	449
NW	0	7	47	91	89	81	29	14	8	366
NNW	0	10	40	54	30	16	8	9	4	171
Sub-Total:	126	111	311	429	369	324	191	120	91	2072

Average Wind Speed: 4.15 m/s

2003: THIRD QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	129	26	61	36	6	1	1	0	0	260
NNE	0	13	47	15	0	0	0	0	0	75
NE	0	18	22	5	1	0	0	0	0	46
ENE	0	9	20	4	0	0	0	0	0	33
E	0	3	8	1	0	0	0	0	0	12
ESE	0	2	2	0	0	1	0	0	0	5
SE	0	2	2	0	0	0	0	0	0	4
SSE	0	2	3	0	0	0	0	0	0	5
S	0	1	1	0	0	0	0	0	0	2
SSW	0	1	1	0	0	0	0	0	0	2
SW	0	2	4	4	1	0	0	0	0	11
WSW	0	7	20	15	5	5	8	2	2	64
W	0	3	33	55	74	67	28	31	15	306
WNW	0	6	38	124	160	79	53	13	7	480
NW	0	13	77	138	129	94	38	15	2	506
NNW	0	10	85	105	55	28	9	1	0	293
Sub-Total:	129	118	424	502	431	275	137	62	26	2104

Average Wind Speed: 3.68 m/s

2003: FOURTH QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	402	9	22	7	2	1	0	1	0	444
NNE	0	7	10	1	0	0	0	0	0	18
NE	1	13	19	2	1	0	0	0	0	36
ENE	0	17	17	10	1	0	0	0	0	45
E	0	14	27	20	4	1	0	0	0	66
ESE	0	22	54	29	6	6	4	1	0	122
SE	0	25	54	46	47	28	13	9	14	236
SSE	0	18	31	24	16	22	21	14	16	162
S	0	12	22	11	8	1	0	1	1	56
SSW	0	12	17	3	2	0	0	0	0	34
SW	0	16	19	4	0	0	0	0	0	39
WSW	0	18	36	18	12	4	3	0	4	95
W	0	28	44	62	31	27	9	4	6	211
WNW	0	24	47	58	52	31	14	3	2	231
NW	0	21	45	45	33	37	15	9	2	207
NNW	0	19	38	34	16	9	5	3	11	135
Sub-Total:	403	275	502	374	231	167	84	45	56	2137

Average Wind Speed: 2.86m/s

2004: ANNUAL
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	1075	42	119	80	25	14	9	3	9	1376
NNE	0	44	88	22	5	1	2	0	0	162
NE	0	52	63	9	1	0	1	1	0	127
ENE	1	54	55	8	2	0	1	0	0	121
E	1	49	90	24	7	0	0	1	0	172
ESE	0	59	116	92	28	13	3	1	3	315
SE	0	63	132	122	78	40	20	25	41	521
SSE	0	38	78	69	56	42	33	27	58	401
S	0	38	59	22	11	8	4	4	4	150
SSW	0	28	30	12	4	2	1	0	0	77
SW	0	41	59	27	5	3	2	0	0	137
WSW	0	35	86	68	48	38	26	24	41	366
W	0	59	170	222	207	182	128	84	112	1164
WNW	0	57	211	335	328	256	125	52	18	1382
NW	0	47	200	272	271	229	111	45	26	1201
NNW	0	32	154	196	117	69	56	43	59	726
Sub-Total:	1077	738	1710	1580	1193	897	522	310	371	8398

Average Wind Speed: 3.52 m/s

2004: FIRST QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	347	11	17	9	3	2	2	1	0	392
NNE	0	9	15	3	1	0	0	0	0	28
NE	0	15	12	1	1	0	0	1	0	30
ENE	1	18	14	1	0	0	1	0	0	35
E	0	23	33	8	6	0	0	1	0	71
ESE	0	16	43	31	13	8	2	1	1	115
SE	0	22	41	42	53	23	10	6	18	215
SSE	0	10	31	28	33	20	18	11	22	173
S	0	13	22	9	7	3	2	2	4	62
SSW	0	10	10	3	2	1	0	0	0	26
SW	0	20	20	9	2	1	0	0	0	52
WSW	0	11	33	23	13	0	2	1	2	85
W	0	10	53	63	27	23	10	3	1	190
WNW	0	19	56	75	47	26	17	6	4	250
NW	0	12	48	49	43	31	15	10	5	213
NNW	0	11	37	27	22	7	10	10	5	129
Sub-Total:	348	230	485	381	273	145	89	53	62	2066

Average Wind Speed: 3.04 m/s

2004: SECOND QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	123	6	20	19	7	4	2	0	4	185
NNE	0	5	15	6	1	0	1	0	0	28
NE	0	9	8	3	0	0	0	0	0	20
ENE	0	9	8	0	0	0	0	0	0	17
E	0	4	3	1	0	0	0	0	0	8
ESE	0	0	5	3	0	0	0	0	0	8
SE	0	4	4	5	2	2	0	1	0	18
SSE	0	5	1	4	3	2	0	1	0	16
S	0	5	5	0	2	0	0	0	0	12
SSW	0	4	3	2	0	0	0	0	0	9
SW	0	6	8	8	1	1	0	0	0	24
WSW	0	3	20	17	15	15	15	17	29	131
W	0	7	42	75	94	95	79	57	95	544
WNW	0	12	47	111	136	118	58	23	9	514
NW	0	7	48	70	79	89	42	17	11	363
NNW	0	9	38	43	34	35	21	13	21	214
Sub-Total:	123	95	275	367	374	361	218	129	169	2111

Average Wind Speed: 4.51 m/s

2004: THIRD QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	140	16	61	47	8	4	2	0	2	280
NNE	0	14	43	8	2	0	0	0	0	67
NE	0	18	30	3	0	0	1	0	0	52
ENE	0	4	15	2	0	0	0	0	0	21
E	0	4	5	0	0	0	0	0	0	9
ESE	0	1	4	1	1	0	0	0	0	7
SE	0	1	4	8	3	1	1	0	0	18
SSE	0	4	3	4	2	0	0	0	0	13
S	0	2	8	5	0	0	0	0	0	15
SSW	0	2	4	3	1	1	1	0	0	12
SW	0	3	9	5	1	0	0	0	0	18
WSW	0	6	6	14	14	20	9	6	10	85
W	0	11	31	67	77	62	39	23	15	325
WNW	0	6	62	107	118	90	44	22	4	453
NW	0	12	66	117	120	93	41	10	3	462
NNW	0	5	53	112	39	20	11	6	13	259
Sub-Total:	140	109	404	503	386	291	149	67	47	2096

Average Wind Speed: 3.77 m/s

2004: FOURTH QUARTER
WIND SPEEDS AT 10 METER HEIGHT (m/s)

SECTOR	0-1	1-2	2-3	3-4	4-5	5-6	6-7	7-8	>=8	Total
N	465	9	21	5	7	4	3	2	3	519
NNE	0	16	15	5	1	1	1	0	0	39
NE	0	10	13	2	0	0	0	0	0	25
ENE	0	23	18	5	2	0	0	0	0	48
E	1	18	49	15	1	0	0	0	0	84
ESE	0	42	64	57	14	5	1	0	2	185
SE	0	36	83	67	20	14	9	18	23	270
SSE	0	19	43	33	18	20	15	15	36	199
S	0	18	24	8	2	5	2	2	0	61
SSW	0	12	13	4	1	0	0	0	0	30
SW	0	12	22	5	1	1	2	0	0	43
WSW	0	15	27	14	6	3	0	0	0	65
W	0	31	44	17	9	2	0	1	1	105
WNW	0	20	46	42	27	22	6	1	1	165
NW	0	16	38	36	29	16	13	8	7	163
NNW	0	7	26	14	22	7	14	14	20	124
Sub-Total:	466	304	546	329	160	100	66	61	93	2125

Average Wind Speed: 2.74 m/s

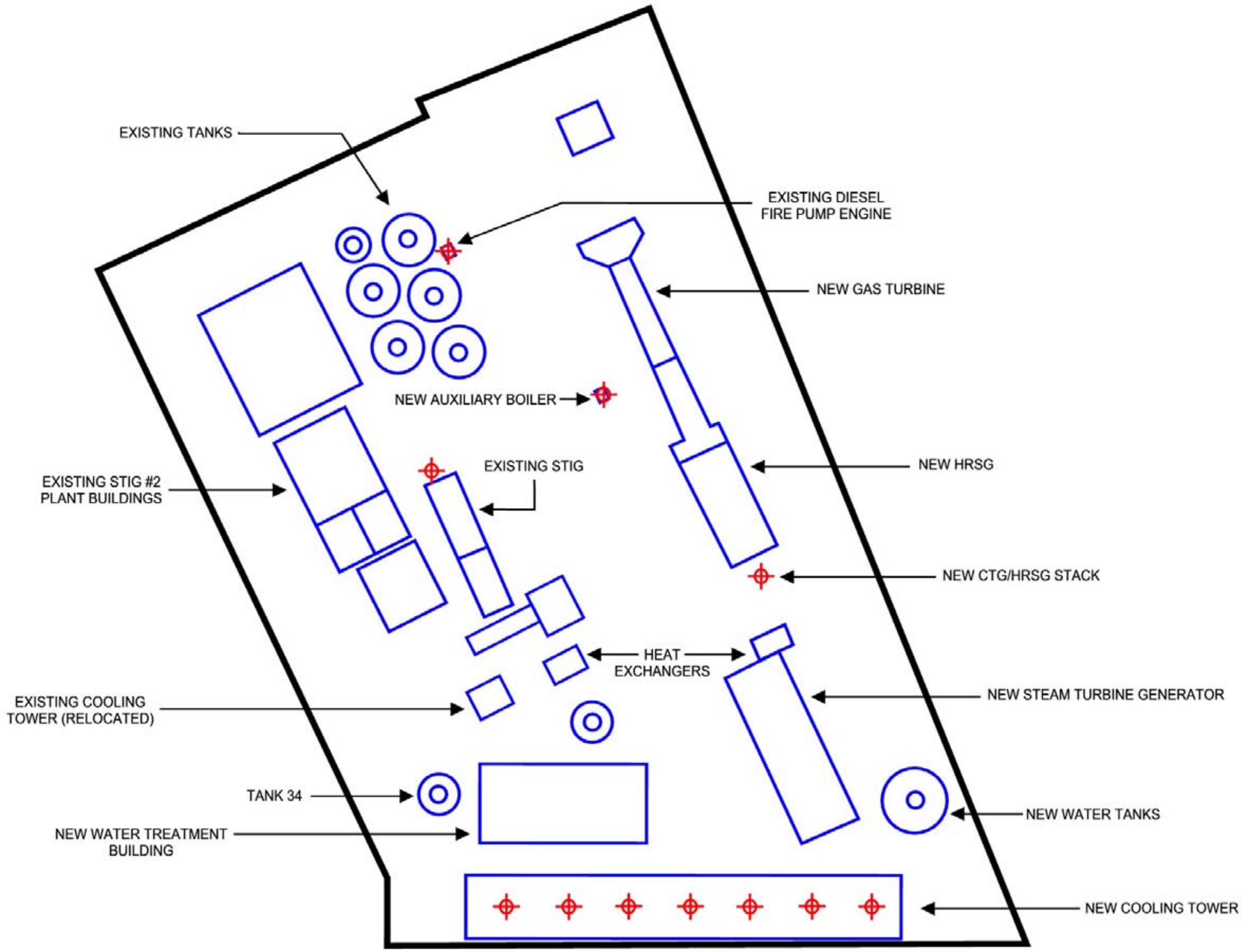


FIGURE 5.1B-7R
Building Layout for GEP Analysis

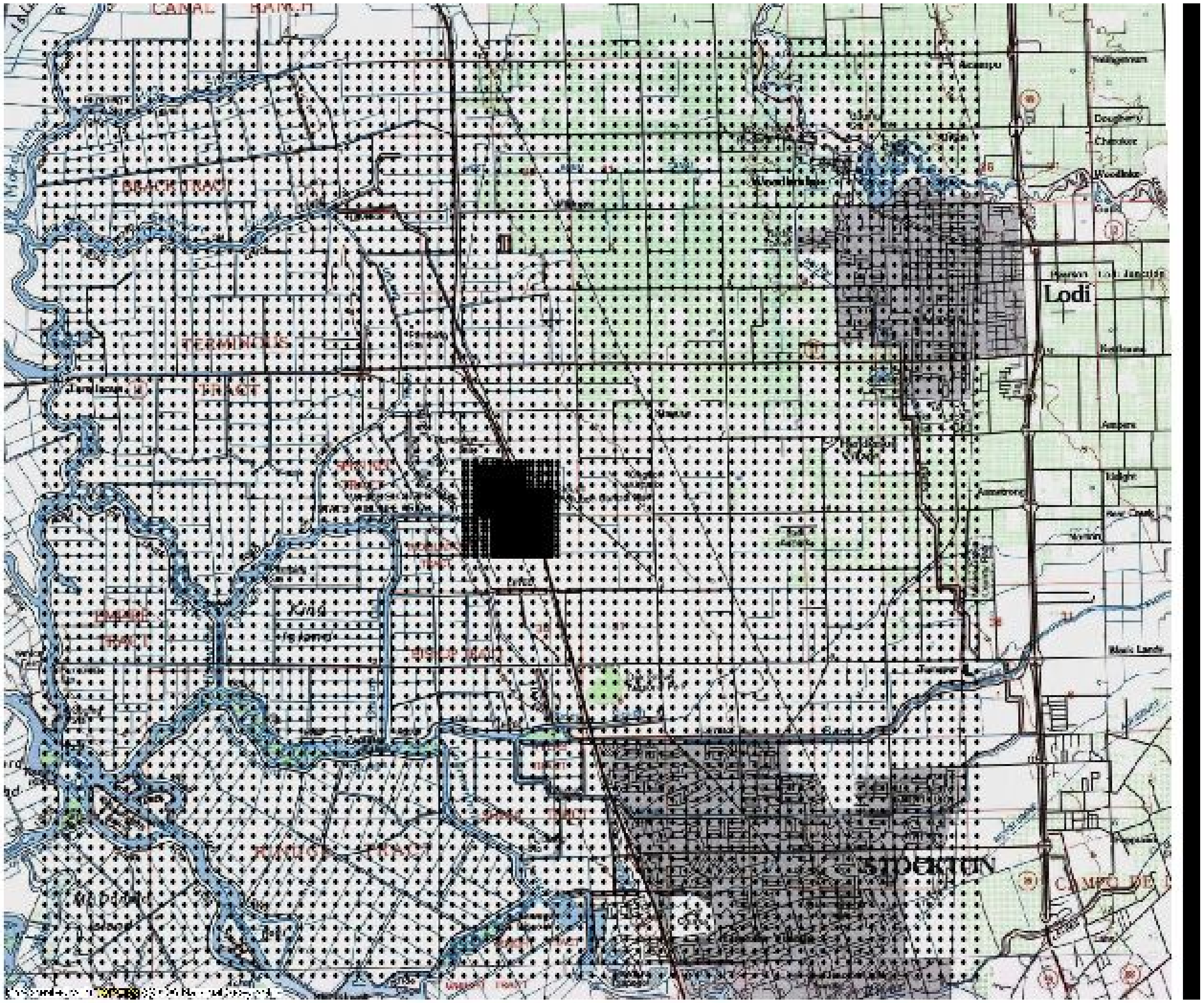


FIGURE 5.1B-8
Layout of the Receptor Grids

APPENDIX 5.1C

Evaluation of Best Available Control Technology

The LEC project is required to use best available control technology on the combustion turbine/HRSG, the auxiliary boiler, and the cooling tower for various pollutants, in accordance with the requirements of the federal PSD and the District new source review programs. The applicability of BACT requirements under PSD regulations is discussed in Section 5.1.7.1. For sources subject to PSD, BACT is defined in 40 CFR 52.21(j) as:

> "an emissions limitation…based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant…"

The applicability of BACT requirements under District regulations is discussed in Section 5.1.7.3. The SJVAPCD defines BACT as:

> "the most stringent emission limitation or control technique of the following:

- Achieved in practice for such category and class of source;
- Contained in any State Implementation Plan approved by the Environmental Protection Agency for such category and class of source. A specific limitation or control technique shall not apply if the owner of the proposed emissions unit demonstrates to the satisfaction of the APCO that such a limitation or control technique is not presently achievable; or
- Contained in an applicable federal New Source Performance Standard; or
- Any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found by the APCO to be cost effective and technologically feasible for such class or category of sources or for a specific source." [Rule 2201, Section 3.9]

The federal PSD BACT requirement is applicable for NOx and CO, while the District BACT requirement is applicable for all pollutants. The emission rates and control technologies determined to be BACT for this project are discussed in detail in the following sections. For the CTG/HRSG, separate determinations are provided for normal operation and startup/shutdown operation.

5.1C.1 BACT for the CTG/HRSG: Normal Operations

5.1C.1.1 NOx Emissions

5.1C.1.1.1 Achievable Controlled Levels and Available Control Options

The most recent NOx BACT listings for combined-cycle combustion turbines in this size range are summarized in Table 5.1C-1. The most stringent NOx limit in these recent BACT determinations is a 2.0 ppm[1] limit averaged over a 1-hour averaging period, excluding startups and shutdowns. This level is achieved using DLN combustors and SCR. The Elk Hills project was given the option of using SCONOx instead of SCR, with a NOx limit of 2.5 ppm.

The SJVAPCD adopted Rule 4703 (Stationary Gas Turbines) to limit NOx emissions from these devices. Rule 4703 specifies an enhanced Tier II NOx emission limit of 3 ppmv @ 15% O_2 for natural gas-fired combustion gas turbines rated at no less than 10 MW and equipped with SCR (April 30, 2008 deadline).

SCONOx is a NOx reduction system produced by Goal Line Environmental Technologies. It is now distributed by EmeraChem as EMx. This system uses a single catalyst to oxidize both NOx and CO and then a regeneration system to convert the NO_2 to N_2 and water vapor. The system does not use ammonia as a reagent. The EMx process has been demonstrated in practice on much smaller gas turbines, including Redding Electric Utility's (REU) Unit 5, a 43-MW Alstom GTX100 combined-cycle gas turbine. While the technology has never been demonstrated on a gas turbine the size of the 7FA, the technology is considered by the manufacturer to be scalable.

The SCR system uses ammonia injection to reduce NOx emissions. SCR systems have been widely used in combined-cycle gas turbine applications of all sizes, including the 7FA and the larger H-class. The SCR process involves the injection of ammonia into the flue gas stream via an ammonia injection grid upstream of a reducing catalyst. The ammonia reacts with the NOx in the exhaust stream to form N_2 and water vapor. The catalyst does not require regeneration, but must be replaced periodically—approximately every 3 years.

Either SCR or SCONOx technology, in combination with dry low-NOx (DLN) combustion, will achieve a NOx emission level of 2.0 ppmvd@ 15% O_2.

5.1C.1.1.1.1 Environmental Impacts

The use of SCR will result in ammonia emissions due to an allowable ammonia slip limit of 10 ppmvd @ 15% O_2. A health risk screening analysis of the proposed project using air dispersion modeling showed the acute hazard index and a chronic hazard index each to be much less than 1, based on an ammonia slip limit of 10 ppmv @ 15% O_2. In accordance with the District's Integrated Air Toxics program and currently accepted practice, a hazard index below 1.0 is not considered significant. Therefore, the toxic impact of the ammonia slip resulting from the use of SCR is deemed to be not significant and is not a sufficient reason to eliminate SCR as a control alternative.

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[1] All turbine/HRSG exhaust emissions concentrations shown are corrected to 15% O2.

TABLE 5.1C-1
Recent NOx BACT Determinations for Combustion Turbines/HRSGs

Facility	District/State	NOx Limit	Averaging Prd	Control Method Used	Date Permit Issued	Source
Gateway Generating Station	BAAQMD	2.0 ppmc	1 hour	DLN/SCR	July 2008 (proposed permit)	BAAQMD
Colusa Generating Station	EPA Region 9	2.0 ppmc	1 hour	DLN/SCR	May 2008	EPA AQIA
Russell City Energy Center	BAAQMD	2.0 ppmc	1 hour	DLN/SCR	June 2007	BAAQMD website
Blythe Energy LLC (Blythe II)[a]	MDAQMD	2.0 ppmc	3 hours	DLN/SCR	April 2007	PSD permit
San Joaquin Valley Energy Center	EPA Region 9	2.0 ppmc	1 hour	DLN/SCR	August 2006	PSD permit
Mountainview Power	SCAQMD	2.0 ppmc	1 hour	DLN/SCR	2004	amendment
Pastoria Energy LLC	SJVAPCD	2.5 ppmc	1 hour	DLN/SCR	2004	PSD amendment
Magnolia Power Project	SCAQMD	2.0 ppmc	3 hours	DLN/SCR	February 2004	SCAQMD website
Vernon City Power & Light	SCAQMD	2.0 ppmc	2 hour	DLN/SCR	February 2004	SCAQMD website
PSO Southwestern Power Plant	Oklahoma	9.0 ppmc	--	DLN	February 2007	EPA RBLC
Rocky Mountain Energy Center	Colorado	3.0 ppmc	1 hour	DLN/SCR	May 2006	EPA RBLC
Sierra Pacific Power Company	Nevada	2.0 ppmc	3 hours	DLN/SCR	August 2005	EPA RBLC
Wanapa Energy Center	Oregon	2.0 ppmc	3 hours	DLN/SCR	August 2005	EPA RBLC
Crescent City Power, LLC	Louisiana	3.0 ppmc	annual	DLN/SCR	June 2005	EPA RBLC
Berrien Energy, LLC	Michigan	2.5 ppmc	24 hours	DLN/SCR	April 2005	EPA RBLC
Turner Energy Center[b]	Oregon	2.0 ppmc	1 hour	DLN/SCR	January 2005	EPA RBLC

Notes:

a. Construction on hold.

b. RBLC record indicates that project will not be built.

The ammonia emissions resulting from the use of SCR may have another environmental impact through their potential to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. However, the SJVAPCD has stated that because of high background levels of ammonia, the formation of ammonium nitrate and ammonium sulfate in the San Joaquin Valley air basin is limited by the formation of nitrates and sulfates and not driven by the amount of ammonia in the atmosphere. Therefore, ammonia emissions from the proposed SCR system are not expected to contribute significantly to the formation of secondary particulate matter within the SJVAPCD.

A second potential environmental impact that may result from the use of SCR involves the storage and transport of anhydrous ammonia. Although ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident and is already being stored and used at the existing STIG #2 plant. As discussed in Section 2.0, the project will utilize the existing ammonia delivery system, which consists of an ammonia storage tank, spill containment basin, and refilling station with a spill containment basin and sump—new ammonia storage facilities will not be constructed as part of the proposed project. NCPA is already required to maintain a Risk Management Plan (RMP) and to implement a Risk Management Program to prevent accidental releases of ammonia. The RMP will be updated to include use of ammonia at the LEC (see Section 5.5 of the AFC). The RMP provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases. The accident prevention and emergency response requirements reflect existing safety regulations and sound industry safety codes and standards. Thus, the potential environmental impact due to anhydrous ammonia use at the LEC is minimal and does not justify the elimination of SCR as a control alternative.

Regeneration of the EMx catalyst is accomplished by passing hydrogen gas over an isolated catalyst module. The hydrogen gas is generated by reforming steam, so additional steam would be required beyond that for which the project is designed. This would require an increase in the size of the auxiliary boiler as well as an increase in expected boiler operation and emissions.

5.1C.1.1.1.2 Achieved in Practice Evaluation

While there are no formal "achieved in practice" criteria in the SJVAPCD, the SCAQMD has established formal criteria for determining when emission control technologies should be considered achieved in practice (AIP) for the purposes of BACT determinations. The criteria include the elements outlined below.

- Commercial Availability: At least one vendor must offer this equipment for regular or full-scale operation in the United States. A performance warranty or guarantee must be available with the purchase of the control technology, as well as parts and service.
- Reliability: All control technologies must have been installed and operated reliably for at least six months. If the operator did not require the basic equipment to operate daily, then the equipment must have at least 183 cumulative days of operation. During this period, the basic equipment must have operated (1) at a minimum of 50% design

capacity; or (2) in a manner that is typical of the equipment in order to provide an expectation of continued reliability of the control technology.

- Effectiveness: The control technology must be verified to perform effectively over the range of operation expected for that type of equipment. If the control technology will be allowed to operate at lesser effectiveness during certain modes of operation, then those modes of operation must be identified. The verification shall be based on a performance test or tests, when possible, or other performance data.

Each of these criteria is discussed separately below for SCR and for EMx.

SCR Technology – SCR has been achieved in practice at numerous combustion turbine installations throughout the world. There are several utility-scale combined cycle projects that limit NOx emissions to 2.0 ppm, including the Mountainview Power Plant in San Bernardino County; the Inland Empire Energy Center in Riverside County; and the Cosumnes Power Plant in Sacramento County. An evaluation of the proposed AIP criteria as applied to the achievement of extremely low NOx levels (2.0 ppm and lower) using SCR technology is summarized below.

- Commercial Availability: SCR technology is available with standard commercial guarantees for NOx levels at least as low as 2 ppm. Consequently, this criterion is satisfied.
- Reliability: SCR technology has been shown to be capable of achieving NOx levels consistent with a 2.0 ppm permit limit during extended, routine operations at several commercial power plants. There are no reported adverse effects of operation of the SCR system at these levels on overall plant operation or reliability.
- Effectiveness: SCR technology has been demonstrated to achieve NOx levels of 2.0 ppm and less. Short-term excursions have resulted in NOx concentrations above the permitted level of 2.0 ppm; however, these excursions have not been associated with diminished effectiveness of the SCR system. Rather, these excursions have been associated with SCR inlet NOx levels in excess of those for which the SCR system was designed.
- Conclusion: SCR technology capable of achieving NOx levels of 2.0 ppm is considered to be achieved in practice. The proposed permit limits for the proposed Lodi Energy Center CTG/HRSG include a NOx limit of 2.0 ppm. This proposed limit is consistent with the available data.

EMx Technology – EMx has been demonstrated in service in five applications: the Sunlaw Federal cogeneration plant, the Wyeth BioPharma cogeneration facility, the Montefiore Medical Center cogeneration, the University of California San Diego facility, and the Redding Power Plant. The combustion turbines at these facilities are much smaller than for the proposed LEC turbine. The largest installation of the EMx system is at the Redding Power Plant. The Redding Power Plant currently consists of a single combined cycle 43 MWe Alstom GTX100 combustion turbine with a permitted NOx emission rate of 2.5 ppm. There is a second 43 MWe unit under construction at the Redding Power Plant, but that unit has not begun operation.

A review of NOx continuous emissions monitoring (CEM) data obtained from the EPA's Acid Rain program website[2] indicates a mean NOx level for the unit of less than 1.0 ppm during the period from 2002 to 2007. After the first year of operation, Unit #5 at the REU power plant has experienced only a few hours of non-compliance per year (fewer than 0.1% of the annual operating hours exceed the NOx permit limit of 2.5 ppm). At the lower NOx limit of 2.0 ppm that will be required for the proposed LEC, the CEM data show that the number of non-compliant hours increases to approximately 0.2% of the annual operating hours. The experience at the City of Redding Plant indicates the ability of the EMx system to control NOx emissions to levels of 2.0 ppm and less.

Based on this information, the following paragraphs evaluate the proposed AIP criteria as applied to the achievement of extremely low NOx levels (2.0 ppm) using EMx technology.

- Commercial availability: While a proposal has not been sought, presumably EmeraChem Power would offer standard commercial guarantees for the proposed LEC. Consequently, this criterion is expected to be satisfied.
- Reliability: As discussed above, based on a review of the CEM data for REU Unit #5 the EMx system complied with the 2.0 ppm NOx permit limit but with a few hours each year of excess emissions (approximately 3% of annual operating hours following the first year, and approximately 2% following the second year, dropping to approximately 0.1% after 4 years). This level of performance was also associated with some significant operating and reliability issues. According to a June 23, 2005 letter from the Shasta County Air Quality Management District3, repairs to the EMx system began shortly after initial startup and have continued during several years of operation. Redesign of the EMx system was required due to a problem with the reformer reactor combustion production unit that led to sulfur poisoning of the catalyst. In addition, the EMx system catalyst washings had to occur at a frequency several times higher than anticipated during the first three years of operation, which has resulted in substantial downtime of the combustion turbine. Since the REU installation is the most representative of all of the EMx-equipped combustion turbine facilities for comparison to the proposed LEC, the problems encountered at REU bring into question the reliability of the EMx system for the proposed project.
- Effectiveness: The EMx system at the REU power plant has recently been able to demonstrate compliance with a NOx level of 2.0 ppm. However, there are no EMx-equipped facilities of a size similar to that of the proposed LEC. Consequently, due to the lack of actual performance data, there is some question regarding the effectiveness of the EMx systems on large combustion turbine projects.
- Conclusion: EMx systems are capable of achieving NOx levels of 2.0 ppm and less. However, the operating history at the Redding Power Plant does not support a conclusion that this technology is achieved in practice based on South Coast AQMD guidelines, due mainly to reliability issues.

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[2] Available at http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=prepackaged.results

[3] Letter dated June 23, 2005, from Shasta County Air Quality Management District to the Redding Electric Utility regarding Unit 5 demonstration of compliance with its NOx permit limit.

5.1C.1.1.1.3 Conclusion

Because both SCR and EMx are expected to achieve the proposed BACT NO_x emission limit of 2.0 ppmvd @ 15% O_2 averaged over one hour and neither will cause significant energy, economic, or environmental impacts, neither can be eliminated as viable control alternatives. The concern remains regarding the long-term effectiveness of EMx as a control technology as the technology has not been demonstrated on the turbine used in this project. In addition, LEC is utilizing the new Rapid Response startup process for this turbine (discussed in more detail below) so will already be challenged with integrating a new technology, with the potential for much larger emissions reductions. For these reasons, and because SCR is already in use at the facility, SCR has been selected as the NOx control technology to be used for the LEC.

5.1C.1.1.1.4 Conclusions

BACT must be at least as stringent as the most stringent level achieved in practice, federal NSPS, or district prohibitory rule. Based upon the results of this analysis, the NOx BACT determination of 2.0 ppm @ 15% O_2 on a 1-hour average basis made for recently permitted combined cycle turbine projects in SJVAPCD and elsewhere reflects the most stringent achievable NOx emission limit. The LEC facility will be designed to meet a NOx level of 2.0 ppmv @ 15% O_2 on a 1-hour average basis using SCR.

5.1C.1.2 CO Emissions

5.1C.1.2.1 Achievable Controlled Levels and Available Control Options

Oxidation catalyst technology is commonly used to control CO emissions.

The CARB's BACT guidance document for electric generating units rated at greater than 50 MW[4] indicates that BACT for the control of CO emissions from stationary gas turbines used for combined-cycle and cogeneration power plants is 6 ppmvd @ 15% O_2.

The BAAQMD's BACT guidelines specify that, for natural gas-fired combined-cycle gas turbines larger than 40 MW, a CO limit of 4 ppmv @ 15% O2 has been "achieved in practice."

The SJVAPCD's BACT guidelines contained determinations for gas turbines larger than 50 MW with uniform load and with heat recovery. The SJVAPCD concluded that a CO exhaust concentration of 6 ppmv @ 15% O_2 constituted BACT that had been achieved in practice, while 4.0 ppmv @ 15% O_2 is considered technologically feasible.

A summary of recent CO BACT determinations for large, combined-cycle gas turbines is shown in Table 5.1C-2. Similar facilities using oxidation catalysts have been permitted at between 2.0 and 4.0 ppm CO. CO emission limits for projects in the SCAQMD may be considered to go beyond BACT because (1) the District is a nonattainment area for CO, so more stringent control requirements apply; and (2) applicants in the SCAQMD are required to provide offsets for CO, so there is additional incentive to reduce CO emission levels beyond BACT to minimize offset requirements. We are not aware of any available in-use data that shows whether compliance with the 2.0 ppm limits has been demonstrated in practice.

[4] CARB, "Guidance for Power Plant Siting and Best Available Control Technology," July 1999.

Published prohibitory rules from the BAAQMD, SMAQMD, SDCAPCD, SJVAPCD, and SCAQMD were reviewed to identify the CO standards that govern existing natural gas-fired simple cycle combustion gas turbines. Of the five prohibitory rules reviewed, the SJVAPCD prohibitory rule for combustion gas turbines is the only one that includes an emission limit for CO (200 ppmv @ 15% O_2). The applicable NSPS (40 CFR 60 Subpart KKKK) does not include a CO limit.

5.1C.1.2.1.1 Conclusions

BACT must be at least as stringent as the most stringent level achieved in practice, required in a federal NSPS or district prohibitory rule, or considered technologically feasible. The proposed CO emission limit of 3 ppmvd @ 15% O_2 on a 3-hour average basis is more stringent than the level currently considered BACT, but is expected to be achievable in practice.

5.1C.1.3 VOC Emissions

5.1C.1.3.1 Achievable Controlled Levels and Available Control Options

Most VOCs emitted from natural gas-fired turbines are the result of incomplete combustion of fuel. Therefore, most of the VOCs are methane and ethane, which are not effectively controlled by an oxidation catalyst. However, oxidation catalyst technology designed to control CO can also provide some degree of control of VOC emissions, especially the more complex compounds and toxic compounds formed in the combustion process. Therefore, use of an oxidation catalyst is generally considered BACT for VOC.

The CARB's BACT guidance document for electric generating units rated at greater than 50 MW[5] indicates that BACT for the control of POC emissions for combined-cycle and cogeneration power plants is 2 ppmvd @ 15% O_2.

The BAAQMD's BACT guidelines specify that, for natural gas-fired combined cycle combustion gas turbines larger than 40 MW, a VOC limit of 2 ppmvd @ 15% O_2 has been "achieved in practice."

The SJVAPCD's BACT guidelines contained a determination for gas turbines rated at larger than 50 MW with uniform load and with heat recovery. The SJVAPCD concluded that a VOC exhaust concentration of 2.0 ppmvd @ 15% O_2 constituted BACT that had been achieved in practice, while 1.5 ppmvd @ 15% O_2 is considered technologically feasible.

The SCAQMD database contains BACT determinations for VOC emissions from two natural gas-fired combined cycle combustion gas turbines at 2.0 ppmvd @ 15% O_2.

Published prohibitory rules from the BAAQMD, SMAQMD, SDCAPCD, SJVAPCD, and SCAQMD were reviewed to identify the VOC standards that govern existing natural gas-fired simple cycle combustion gas turbines. None of the prohibitory rules for combustion gas turbines specify an emission limit for VOC. The applicable NSPS (40 CFR 60 Subpart KKKK) does not include a VOC limit.

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5 Ibid, Table I-1.

TABLE 5.1C-2

ReCent CO BACT Determinations for Combustion Turbines/HRSGs

Facility	District/State	CO Limit	Averaging Prd	Control Method Used	Date Permit Issued	Source
Gateway Generating Station	BAAQMD	4.0 ppmc	3 hours	oxidation catalyst	July 2008 (proposed permit)	BAAQMD
Colusa Generating Station	EPA Region 9	3.0 ppmc	3 hours	oxidation catalyst	May 2008	EPA AQIA
Russell City Energy Center	BAAQMD	4.0 ppmc	3 hours	oxidation catalyst	June 2007	BAAQMD website
Blythe Energy LLC (Blythe II)[a]	MDAQMD	4.0 ppmc	3 hours	oxidation catalyst	April 2007	PSD permit
San Joaquin Valley Energy Center	EPA Region 9	4.0 ppmc	1 hour	oxidation catalyst	August 2006	PSD permit
Pastoria Energy LLC	SJVAPCD	9.0 ppmc	3 hours	oxidation catalyst	2004	PSD amendment
Magnolia Power Project	SCAQMD	2.0 ppmc	1 hour	oxidation catalyst	February 2004	SCAQMD website
Vernon City Power & Light	SCAQMD	2.0 ppmc	3 hour	oxidation catalyst	February 2004	SCAQMD website
PSO Southwestern Power Plant	Oklahoma	25 ppmc	--	oxidation catalyst	February 2007	EPA RBLC
Rocky Mountain Energy Center	Colorado	3.0 ppmc	--	oxidation catalyst	May 2006	EPA RBLC
Sierra Pacific Power Company	Nevada	3.5 ppmc	3 hours	oxidation catalyst	August 2005	EPA RBLC
Wanapa Energy Center	Oregon	2.0 ppmc	3 hours	oxidation catalyst	August 2005	EPA RBLC
Crescent City Power, LLC	Louisiana	4.0 ppmc[b]	annual	oxidation catalyst	June 2005	EPA RBLC
Berrien Energy, LLC	Michigan	2.0 ppmc	3 hours	oxidation catalyst	April 2005	EPA RBLC
Turner Energy Center[c]	Oregon	2.0 ppmc / 3.0 ppmc	1 hour	oxidation catalyst	January 2005	EPA RBLC

Notes:

a. Construction on hold.

b. Separate CO limit set for duct burners; this limit is for turbines only.

c. RBLC record indicates that project will not be built.

A summary of recent VOC BACT determinations for large, combined-cycle gas turbines is shown in Table 5.1C-3. Similar facilities using oxidation catalysts have been permitted at between 1.4 and 2.0 ppm VOC. Although several facilities are shown as having been permitted below these levels, compliance with these 1.0 ppm limits has not been achieved in practice because neither the Blythe II nor the Turner plants has been constructed or operated. Further, the Crescent City limit of 1.1 ppm is not comparable to the limits imposed for the other plants cited because it is an annual average limit and not a short-term limit.

5.1C.1.3.1.1 Conclusions

BACT must be at least as stringent as the most stringent achieved in practice, required in a federal NSPS or district prohibitory rule, or considered technologically feasible. Based upon the results of this analysis, the VOC emission limits of 1.4 and 2.0 ppmv @ 15% O_2 are considered to be BACT for the proposed project.

5.1C.1.4 PM_{10}/$PM_{2.5}$ Emissions

5.1C.1.4.1 Achievable Controlled Levels and Available Control Options

PM emissions from natural gas-fired turbines and HRSGs primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions are minimized by using clean burning pipeline quality natural gas with low sulfur content.

The CARB BACT Clearinghouse, as well as the BAAQMD and SJVAPCD BACT guidelines, identify the use of natural gas as the primary fuel as “achieved in practice” for the control of PM_{10} for combustion gas turbines. The SJVAPCD also requires the use of an air inlet filter cooler and a lube oil vent coalescer to remove ambient particulate matter from the inlet air and to minimize the formation of lube oil mists.

The CARB’s BACT guidance document for stationary gas turbines used for combined-cycle and cogeneration power plant configurations[6] indicates that BACT for the control of PM emissions is an emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 standard cubic foot.

Title 40 CFR Part 60 Subpart KKKK contains the applicable NSPS for combustion gas turbines. Subpart KKKK does not regulate PM_{10} emissions.

Published prohibitory rules from the District, SCAQMD, SJVAPCD, SMAQMD, and SDCAPCD were reviewed to identify the PM_{10} standards that govern natural gas-fired combustion gas turbines. These prohibitory rules do not regulate PM_{10} emissions. The applicable NSPS (40 CFR 60 Subpart KKKK) limits SOx emissions to 0.56 lb/MWh, well above permitted limits for natural gas-fired turbines.

Recent PM_{10} BACT determinations for similarly-sized gas turbines/HRSGs are summarized in Table 5.1C-4.

[6] Ibid, Table I-2.

TABLE 5.1C-3
Recent VOC BACT Determinations for Combustion Turbines/HRSGs

Facility	District/State	VOC Limit	Averaging Prd	Duct Fired?	Date Permit Issued	Source
Gateway Generating Station	BAAQMD	2.0 ppmc	3 hours	yes	July 2008 (proposed permit)	BAAQMD
Colusa Generating Station	EPA Region 9	2.0 ppmc	1 hour	yes	May 2008	EPA AQIA
Russell City Energy Center	BAAQMD	2.0 ppmc	3 hours	yes	June 2007	BAAQMD website
Blythe Energy LLC (Blythe II)[a]	MDAQMD	1.0 ppmc	3 hours	yes	December 2005	CEC website
Magnolia Power Project	SCAQMD	2.0 ppmc	1 hour	yes	February 2004	SCAQMD website
Vernon City Power & Light	SCAQMD	2.0 ppmc	1 hour	yes	February 2004	SCAQMD website
Rocky Mountain Energy Center	Colorado	0.0029 lb/MMBtu	--	unknown	May 2006	EPA RBLC
Sierra Pacific Power Company	Nevada	4.0 ppmc	3 hours	yes	August 2005	EPA RBLC
Crescent City Power, LLC	Louisiana	1.1 ppmc	annual	no[b]	June 2005	EPA RBLC
Turner Energy Center[c]	Oregon	1.0 ppmc	3 hours	yes	January 2005	EPA RBLC

Notes:

a. Construction on hold.

b. Separate VOC limit set for duct burners; this limit is for turbines only.

c. RBLC record indicates that project will not be built.

5.1C.1.4.1.1 Conclusions
Based upon the results of this analysis, the SJVAPCD BACT guideline reflects the most stringent PM_{10} emission limit. The District established a requirement for the use of natural gas as the primary fuel to control PM_{10} emissions from combustion gas turbines. Therefore, the use of natural gas as the primary fuel source constitutes BACT for PM_{10} emissions from combustion gas turbines. Through the use of natural gas, the turbine is expected to be able to meet the proposed emission limit of 9.0 lb/hr without duct firing and 11.0 lb/hr with duct firing. These limits are consistent with or lower than the limits shown in the summary table, with the exception of the Blythe II project. Since the Blythe II project has not yet been constructed or operated and no performance data are available, this permit limit is not considered achieved in practice.

5.1C.1.5 SOx Emissions

5.1C.1.5.1 Achievable Controlled Levels and Available Control Options
The CARB BACT Clearinghouse, as well as the BAAQMD and SJVAPCD BACT guidelines, identifies the use of PUC-quality natural gas or natural gas with a limit on the sulfur content (i.e., 1 grain/100 scf) as the primary fuel as “achieved in practice” for the control of SOx for combustion gas turbines. The two most recent BACT determinations in the SCAQMD did not indicate BACT for SOx.

5.1C.1.5.1.1 Federal NSPS
Title 40 CFR Part 60 Subpart KKKK contains the applicable NSPS for combustion gas turbines. A combustion gas turbine is subject to a SO_2 emission limit of 0.56 lb/MWh.

5.1C.1.5.1.2 District Prohibitory Rules
Published prohibitory rules from the BAAQMD, SJVAPCD, and SCAQMD were reviewed to identify the SO_2 standards that govern existing gas turbines.

- BAAQMD Rule 9-9 (Nitrogen Oxides from Stationary Gas Turbines) is the BAAQMD’s only prohibitory rule that specifically addresses gas turbines but does not limit SO2 emissions. The BAAQMD adopted Rule 9-1 (Sulfur Dioxide) to limit SO2 emissions from all sources. Rule 9-1 prohibits SO2 emissions in excess of 300 ppm. No other BAAQMD Rule or Regulation contains a relevant prohibitory rule regulating either the sulfur content in the fuel or the emission of SO2 from gas turbines.
- SJVAPCD Rule 4703 (Stationary Gas Turbines) is the SJVAPCD’s only prohibitory rule that specifically addresses gas turbines but does not limit SO2 emissions. The SJVAPCD adopted Rule 4301 (Fuel Burning Equipment) to limit SO2 emissions from these devices. Rule 4301 specifies a SO2 emission limit of 200 pounds per hour. The SJVAPCD also adopted Rule 4801 (Sulfur Compounds) to limit emissions of sulfur compounds. Rule 4801 specifies a SO2 emission limit of 0.2%, or 2,000 ppm.
- SCAQMD Rule 1134 (Emissions of Oxides of Nitrogen from Stationary Gas Turbines) is the SCAQMD’s only prohibitory rule that specifically addresses gas turbines; however, it does not limit SO2 emissions. The SCAQMD adopted Rule 431.1 (Sulfur Content of Gaseous Fuels) to reduce SOx emissions from the burning of gaseous fuels in stationary equipment. Rule 431.1 specifies a sulfur limit of 16 grains/100 scf (as H2S) in natural gas sold within the SCAQMD. The SCAQMD also adopted Rule 407 (Liquid and Gaseous Air Contaminants) to limit SO2 emissions from all sources. Rule 407 specifies an emission limit of 2,000 ppm for sulfur compounds (calculated as SO2).

TABLE 5.1C-4
Recent PM_{10} BACT Determinations for Combustion Turbines/HRSGs

Facility	District/State	PM_{10} Limit, no duct firing	PM_{10} Limit, with duct firing	Date Permit Issued	Source
Colusa Generating Station	EPA Region 9	12.9 lb/hr	20.0 lb/hr	May 2008	CEC final decision
Russell City Energy Center	BAAQMD	8.6 lb/hr	11.6 lb/hr	June 2007	BAAQMD website
Blythe Energy LLC (Blythe II)	MDAQMD		6.0 lb/hr[a]	December 2005	CEC website
Magnolia Power Project	SCAQMD	--	11.0 lb/hr	February 2004	SCAQMD website
Vernon City Power & Light	SCAQMD	--	11.0 lb/hr	February 2004	SCAQMD website
Rocky Mountain Energy Center	Colorado	--	0.0074 lb/MMBtu	May 2006	EPA RBLC
Sierra Pacific Power Company	Nevada	--	0.011 lb/MMBtu	August 2005	EPA RBLC
Crescent City Power, LLC	Louisiana	29.6 lb/hr	0.01 lb/MMBtu[b]	June 2005	EPA RBLC
Turner Energy Center[c]	Oregon	--	18 lb/hr	January 2005	EPA RBLC

Notes:

a. Construction on hold.

b. Annual limit.

c. RBLC record indicates that project will not be built.

- SCAQMD Rule 1134 (Emissions of Oxides of Nitrogen from Stationary Gas Turbines) is the SCAQMD's only prohibitory rule that specifically addresses gas turbines; however, it does not limit SO2 emissions. The SCAQMD adopted Rule 431.1 (Sulfur Content of Gaseous Fuels) to reduce SOx emissions from the burning of gaseous fuels in stationary equipment. Rule 431.1 specifies a sulfur limit of 16 grains/100 scf (as H2S) in natural gas sold within the SCAQMD. The SCAQMD also adopted Rule 407 (Liquid and Gaseous Air Contaminants) to limit SO2 emissions from all sources. Rule 407 specifies an emission limit of 2,000 ppm for sulfur compounds (calculated as SO2).

5.1C.1.5.1.3 Conclusions

BACT must be at least as stringent as the most stringent limit achieved in practice, federal NSPS, or district prohibitory rule. Based upon the results of this analysis, the CARB database and BAAQMD and SJVAPCD BACT guidelines reflect the most stringent SOx emission limit. These sources established a requirement for the use of natural gas as the primary fuel to control SOx emissions from combustion gas turbines. Therefore, the use of natural gas as the primary fuel source constitutes BACT for SOx emissions from the gas turbine/HRSG.

5.1C.2 BACT for the CTG/HRSG: Startup/Shutdown

Startup and shutdown periods are a normal part of the operation of combined cycle power plants such as LEC. BACT must also be applied during the startup and shutdown periods of gas turbine/HRSG operation. The BACT limits discussed in the previous section apply to steady-state operation, when the turbine, HRSG, and steam turbine have reached stable operations and the emission control systems are fully operational.

During gas turbine startup, there are equipment and process requirements that must be met in sequential order to protect the equipment. Many of these require holding the gas turbine at low loads, where operation is inefficient and emissions are relatively high, to allow the HRSG to warm up and steam turbine seals and condenser vacuum to be established. At low turbine loads, the combustors are not yet operating in lean pre-mix mode so turbine-out NOx emission rates are also high during startup. In addition, incomplete combustion at low loads results in higher CO and VOC emission rates. Further, the post-combustion controls that are used to achieve additional emissions reductions (SCR and oxidation catalyst) require specific exhaust temperature ranges to be fully effective. The use of SCR to control NOx is not technically feasible when the surface of the SCR catalyst is below the manufacturer's recommended operating range. When surface temperatures are low, ammonia will not react completely with the NOx, resulting in excess NOx emissions or excess ammonia slip. The oxidation catalyst is not effective at controlling CO emissions when exhaust temperature is outside the optimal temperature range. Therefore, the BACT determinations for NOx, CO, and VOC during normal, steady-state operation are not applicable during startup and shutdown. However, since SO_2 and PM_{10} emissions result from the characteristics of the fuel burned and do not rely on any emissions control system, the BACT determinations for SO_2 and PM_{10} emissions are applicable during startup and shutdown as well.

Because NOx, CO, and VOC emissions during startup and shutdown are not effectively reduced by combustion controls or add-on control devices, the emission rates themselves cannot be effectively reduced. Therefore, the pound per hour NOx, CO, and VOC limits proposed by the applicant for startup and shutdown periods represent achievable emissions limits based on experience with other, similar turbine projects and are considered BACT for startup and shutdown.

Since the emission rates cannot be reduced, startup emissions must be addressed by minimizing the amount of time the gas turbine and HRSG spend in startup. Efforts have been made by turbine and HRSG manufacturers to develop ways of reducing the time required to ramp up the CTG load to where the DLN combustors will be effective and exhaust temperatures will allow the control devices to be effective. LEC is proposing to utilize a new Rapid Response process for this project. Rapid Response includes the following project features:

- HRSG design: The HRSG will be designed to optimize heat transfer to the tubes, which will allow the HRSG to heat up more quickly. This will reduce gas turbine hold time at low load, especially during cold startups.
- Auxiliary boiler: The proposed project includes an auxiliary steam boiler that will provide steam during startup. The auxiliary boiler steam will preheat the CTG fuel and provide steam turbine sealing steam prior to CTG startup, thereby allowing the condenser vacuum to be established and the condenser to be in a condition ready to accept steam earlier in the startup cycle.

Both of these project design features are expected to reduce hold times for the gas turbine and therefore to allow the gas turbine/HRSG to reduce startup times, especially for cold and warm startups. Because this Rapid Response process has not yet been demonstrated on an operating gas turbine plant, LEC cannot assume the risk that the process will not operate as advertised by GE. Therefore, the NOx, CO, and VOC emissions limits proposed for the project assume that, as a worst case, the Rapid Response process does not allow a significant reduction in startup times.

In summary, LEC is proposing to go beyond BACT for startup and shutdown emissions by installing the Rapid Response system, but the applicant is not taking credit for the expected effectiveness of the Rapid Response system in reducing startup emissions.

5.1C.3 BACT for the Auxiliary Boiler

5.1C.3.1 NOx Emissions

5.1C.3.1.1 Achievable Controlled Levels and Available Control Options

NOx is formed during combustion through two mechanisms: (1) thermal NOx, which is the oxidation of elemental nitrogen in combustion air; and (2) fuel NOx, which is the oxidation of fuel-bound nitrogen. Since natural gas is relatively free of fuel-bound nitrogen, the contribution of this second mechanism to the formation of NOx emissions in natural gas-fired equipment is minimal and thermal NOx is the chief source of NOx emissions. Thermal NOx formation is a function of residence time, oxygen level, and flame temperature, and can be minimized by controlling these elements in the design of the combustion equipment.

There are two basic means of controlling NOx emissions from boilers: combustion controls and post-combustion controls. Combustion controls act to reduce the formation of NOx during the combustion process, while post-combustion controls remove NOx from the exhaust stream. Combustion control technologies for this type of boiler application include low-NOx burners, flue gas recirculation and staged combustion. Post-combustion controls include SCR and selective non-catalytic reduction (SNCR). These are discussed below in order of most effective to least effective.

Selective Catalytic Reduction. The effectiveness of an SCR system requires the catalyst, and thus the treated exhaust stream, to be within a certain temperature range for the NOx reduction reaction to take place. The auxiliary boiler will be operated to support the Rapid Response turbine startup process and will be operated only up to 468 hours per year. The boiler is designed to provide 45,000 lb/hr of steam, with a minimum load of approximately 20,000 lb/hr to provide steam for steam turbine seals and sparging and the remaining 25,000 lb/hr for fuel gas heating. The majority of boiler operations are expected to be at low load, where the exhaust gas temperature is expected to be below the minimum needed for effective SCR control. While the boiler will operate at full load periodically, the length of time at which it will operate is expected to be so short that the SCR system could rarely, if ever, be used effectively. Therefore, this technology is not considered technically feasible for the auxiliary boiler in this application.

Selective Noncatalytic Reduction (SNCR). SNCR involves injection of ammonia or urea with proprietary conditions into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1200 to 2000°F. The exhaust temperature for the proposed auxiliary boiler is 375°F, well below the minimum SNCR operating temperature. Therefore, SNCR is not technically feasible for this application.

Ultra-Low NOx Burners with Flue Gas Recirculation (FGR). Low-NOx burners with FGR are commonly used on industrial-sized package boilers such as the LEC auxiliary boiler. These burners minimize the formation of thermal NOx and FGR reduces the oxygen in the combustion zone to further reduce NOx formation. Ultra-low NOx burners with FGR can achieve NOx emission rates of 7 to 9 ppmvd @ 3% O_2 without post-combustion controls. A 9 ppm emission rate was recently accepted as BACT for the Colusa Generating Station auxiliary boiler and was considered the lowest technologically feasible emission rate for that particular application. A summary of the permitted emissions limits for other, similar boilers is provided in Table 5.1C-5 below.

5.1C.3.1.1.1 District BACT Determinations

The SJVAPCD’s BACT determination for boilers in this size range with variable loads shows that less than 15 ppmc is considered achieved in practice while 9 ppm is considered technically feasible.

The BAAQMD has determined that 9 ppmc is achieved in practice while 7 ppmc is considered technologically feasible. However, the BAAQMD BACT guideline indicates that SCR is needed to achieve 7 ppmc, and, as discussed above, SCR is not feasible for this application.

5.1C.3.1.1.2 District Prohibitory Rules

The SJVAPCD is proposing to adopt more stringent boiler NOx control rules in the near future as part of its ozone and $PM_{2.5}$ attainment strategies. Rule 4306 would require natural gas-fired boilers of this size range and limited annual fuel use to achieve a NOx limit of 30 ppmvd @ 3% O_2. Proposed new Rule 4320 will be applicable to the proposed auxiliary boiler and will require compliance with a NOx limit of 7 ppmvd @ 3% O_2. NCPA has obtained an emissions guarantee of 7 ppm without SCR, so the new auxiliary boiler will comply with the proposed NOx limit in the new prohibitory rule.

5.1C.3.1.1.3 Conclusions

BACT must be at least as stringent as the most stringent limit achieved in practice, federal NSPS, or district prohibitory rule. Based upon the results of this analysis, the proposed 7 ppm NOx limit represents BACT for this application.

5.1C.3.2 VOC Emissions

5.1C.3.2.1 Achievable Controlled Levels and Available Control Options

VOC emissions during natural gas combustion result from incomplete combustion of the fuel gas. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. Since those practices tend to increase NOx emissions, the effectiveness of the NOx control system may affect the ability of the boiler to achieve low VOC emission rates.

5.1C.3.2.1.1 District BACT Determinations

The SJVAPCD's BACT determination for boilers in this size range with variable loads shows that the use of natural gas fuel is considered to be BACT for VOCs.

The BAAQMD has determined that BACT for boilers in this size range is the use of good combustion practices for VOC control.

5.1C.3.2.1.2 District Prohibitory Rules

SJVAPCD draft Rule 4320 does not contain a VOC limit.

5.1C.3.2.1.3 Conclusions

BACT must be at least as stringent as the most stringent limit achieved in practice, federal NSPS, or district prohibitory rule. Based upon the results of this analysis, the proposed 10 ppm VOC limit represents BACT for this application. The proposed limit is expected to be achievable through the use of good combustion practices.

5.1C.3.3 SO_2 and PM_{10} Emissions

5.1C.3.3.1 Achievable Controlled Levels and Available Control Options

SO_2 and PM_{10} emissions from natural gas combustion result from sulfur and other impurities in the fuel. Emissions of these pollutants will be minimized through the use of low sulfur pipeline quality natural gas. There are no add-on control technologies that are effective in reducing SO_2 and PM_{10} emissions from naturally low-emitting natural gas-fired boilers.

TABLE 5.1C-5
Recent NOx and CO BACT Determinations for Medium-Sized Auxiliary Boilers

Facility	District/State	Heat Input Rating (MMBtu/hr HHV)	NOx Limit	CO Limit	Date Permit Issued	Source
Colusa Generating Station	EPA Region 9	44	9	50	May 2008	CEC final decision
Genentech	BAAQMD	97	9	50	September 2005	CARB BACT Clearinghouse
Medimmune, Inc	Maryland	29.4	9	n/a	January 2008	RBLC # MD-0037
CPV Warren	Virginia	97	0.011 lb/MMBtu [a]	0.036 lb/MMBtu[c]	January 2008	RBLC # VA-0308
Minnesota Steel Industries	Minnesota	99	0.035 lb/MMBtu[b]	0.08 lb/MMBtu[d]	September 2007	RBLC # MN-0070
Thyssenkrupp Steel and Stainless USA, LLC	Alabama	64.9	0.035 lb/MMBtu[b]	0.040 lb/MMBtu[c]	August 2007	RBLC # AL-0230
Daimler Chrysler Corporation	Ohio	20.4	0.0350 lb/MMBtu[b]	0.0830 lb/MMBtu[d]	May 2007	RBLC # OH-0309

Notes:

a. Equivalent to approximately 9 ppmc NOx.

b. RBLC record shows 0.0035 lb/MMBtu, but based on rated heat input and hourly limit, this is believed to be a typographical error. This is equivalent to approximately 27 ppmc NOx.

c. Equivalent to approximately 50 ppmc CO.

d. Equivalent to approximately 100 ppmc CO.

5.1C.3.3.1.1 District BACT Determinations

The SJVAPCD and BAAQMD BACT guidelines both indicate that the use of natural gas fuel is considered BACT for boilers.

5.1C.3.3.1.2 Conclusions

Use of pipeline quality natural gas is considered BACT for this boiler application. The proposed emissions limitations are expected to be achievable with natural gas firing.

APPENDIX 5.1D

Revised July 2009

Screening Health Risk Assessment

APPENDIX 5.1D (REVISED JULY 2009)

Screening Health Risk Assessment

The screening level health risk assessment has been revised using CARB's Hotspots Analysis and Reporting Program (HARP) computer program (Version 1.4a, July 2008) and associated guidance in the OEHHA's *Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments* (August 2003). The HARP model was used to assess cancer risk as well as chronic and acute risk impacts. The most recent health database[1] provided by CARB, reflecting the RELs adopted by OEHHA in December 2008, has been used. Although the December 2008 RELs include 8-hour RELs for acetaldehyde, acrolein and formaldehyde, these 8-hour RELs have not yet been incorporated into the HARP software.

Modeling Inputs

HAP emission rates used in the screening health risk assessment are shown in Appendix 5.1A, Table 5.1A-8R (emission factors and emission rates in pounds per hour and tons per year), and in Tables 5.1D-2R, 5.1D-3R and 5.1D-4R (emission rates in grams per second for the CTG/HRSG and the auxiliary boiler and stack parameters used for modeling, respectively). Maximum hourly heat input rate was used in calculating emissions for acute impacts; annual average heat input rate was used in calculating emission rates for the chronic and cancer risk analyses. Stack parameters reflect the turbine operating cases that produced the highest 1-hour average and annual average unit impacts in the screening analysis.

Risk Analysis Method

The dispersion analysis was performed using AERMOD in accordance with the procedures outlined in Appendix 5.1B, using the modeling inputs described above. AERMOD produces output files containing modeled concentrations of each compound shown in Table 5.1D-2R at every receptor. However, because the HARP model was designed to use modeling output files from the ISCST3 model, rather than the current recommended guideline AERMOD model, the AERMOD results must be reformatted before they can be used in HARP.

The HARP On-Ramp is a tool provided by CARB that reformats output files from models other than ISCST3 so that they can be read by the HARP Risk Module. Version 1 of the On-Ramp tool was used to create files required by HARP to complete the screening health risk assessment.

Summary of Results

The results of the screening level health risk assessment are summarized in Table 5.1D-1R.

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[1] February 2009, available at http://www.arb.ca.gov/toxics/harp/data.htm.

TABLE 5.1D-1R
Screening Level Risk Assessment Results

Risk Methodology	Lodi Energy Center
Modeled Residential Cancer Risk (in one million)	
Residential: Derived (OEHHA) Method at PMI	0.4
Residential: Derived (OEHHA) Method at nearest residential receptor	0.04
Modeled Worker Cancer Risk (in one million)	
Worker Exposure: Derived (OEHHA) Method at PMI	0.07
Worker Exposure: Derived (OEHHA) Method at workplace	0.007
Modeled Acute and Chronic Impacts	
Acute HHI	0.01
Chronic HHI	0.006

As shown in Table 5.1D-1R, the cancer risk from the project is well below the significance level of 10 in one million. In addition, the acute and chronic health hazard indices are well below the significance level of one. The analysis of potential cancer risk described in this section employs extremely conservative methods and assumptions, as follows:

- The analysis includes representative weather data over 5 years to ensure that the least favorable conditions producing the highest ground-level concentration of power plant emissions are included. The analysis then assumes that these worst-case weather conditions, which in reality occurred only once in four years, will occur every year for 70 years.
- In this analysis, the power plant is assumed to operate at hourly, daily, and annual emission conditions that produce the highest ground-level concentrations. However, in reality the power plant is expected to operate at a variety of conditions that will produce lower emissions and impacts.
- The analysis assumes that a sensitive individual is at the location of the highest ground-level concentration of power plant emissions continuously over the entire 70-year period. In reality, people rarely live in their homes for 70 years, and even if they do, they leave their homes to attend school, go to work, go shopping, and so on.

The purpose of using these unrealistic assumptions is to consciously overstate the potential impacts. No one will experience exposures as great as those assumed for this analysis. By determining that even this highly overstated exposure will not be significant, there is a high degree of confidence that the much lower exposures that actual persons will experience will not result in a significant increase in cancer risk. In short, the analysis ensures that there will not be significant public health impacts at any location, under any weather condition, or under any operating condition.

The locations of the maximum acute, chronic and cancer risks are shown in Figure 5.1D-1R.

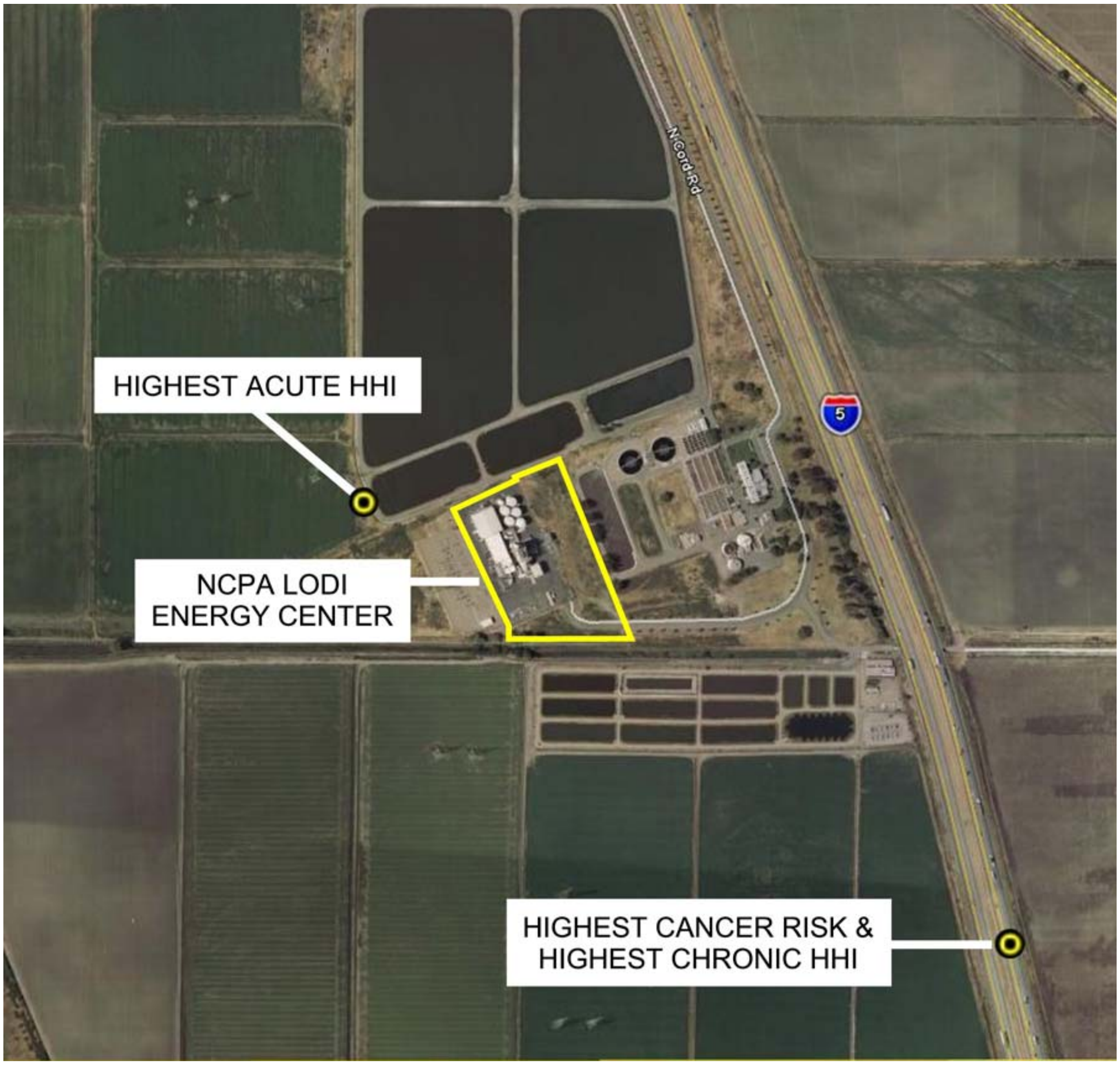

FIGURE 5.1D-1R
Location of Maximum Modeled Health Risks from the LEC Project

Table 5.1D-2R
NCPA Lodi Energy Center
Modeling Inputs for CTG/HRSG Screening Health Risk Assessment
Rev 06/09 Siemens SCC6-5000F 1x1, no duct firing

	Emission Rates, g/s	
Compound	1-hour Avg	Annual Avg
Ammonia	3.624	3.624
Propylene	0.207	0.207
Acetaldehyde	1.080E-02	1.08E-02
Acrolein	1.727E-03	1.727E-03
Benzene	3.239E-03	3.239E-03
1,3-Butadiene	1.161E-04	1.161E-04
Ethylbenzene	8.637E-03	8.637E-03
Formaldehyde	1.916E-01	1.916E-01
Hexane	6.963E-02	6.963E-02
Naphthalene	3.509E-04	3.51E-04
PAHs		
Benzo(a)anthracene	4.191E-05	4.19E-05
Benzo(a)pyrene	2.578E-05	2.58E-05
Benzo(b)fluoranthrene	2.095E-05	2.10E-05
Benzo(k)fluoranthrene	2.040E-05	2.04E-05
Chrysene	4.673E-05	4.67E-05
Dibenz(a,h)anthracene	4.358E-05	4.36E-05
Indeno(1,2,3-cd)pyrene	4.358E-05	4.36E-05
Propylene Oxide	1.285E-02	1.28E-02
Toluene	3.509E-02	3.509E-02
Xylene	1.727E-02	1.727E-02

Table 5.1D-3R
NCPA Lodi Energy Center
Cancer Risk Assessment Modeling Inputs for Aux Boiler
Rev 06/09 Siemens SCC6-5000F 1x1, no duct firing

	Emission Rates, g/s	
Compound	1-hour Avg	Annual Avg
Ammonia	--	--
Propylene	2.430E-03	1.110E-03
Acetaldehyde	1.421E-05	6.490E-06
Acrolein	1.238E-05	5.653E-06
Benzene	2.659E-05	1.214E-05
1,3-Butadiene	--	--
Ethylbenzene	3.164E-05	1.445E-05
Formaldehyde	5.640E-05	2.575E-05
Hexane	2.109E-05	9.631E-06
Naphthalene	1.376E-06	6.281E-07
PAHs		
Benzo(a)anthracene	7.240E-08	3.306E-08
Benzo(a)pyrene	4.826E-08	2.204E-08
Benzo(b)fluoranthrene	7.240E-08	3.306E-08
Benzo(k)fluoranthrene	7.240E-08	3.306E-08
Chrysene	7.240E-08	3.306E-08
Dibenz(a,h)anthracene	4.826E-08	2.204E-08
Indeno(1,2,3-cd)pyrene	7.240E-08	3.306E-08
Propylene Oxide	--	--
Toluene	1.215E-04	5.548E-05
Xylene	9.033E-05	4.125E-05

Table 5.1D-4R
NCPA Lodi Energy Center
Stack Parameters for Screening HRA
Rev 06/09 Siemens SCC6-5000F 1x1, no duct firing

Stack Parameters				
	Stack Diam (m)	Stack Ht (m)	Exhaust Temp (deg K)	Exhaust Velocity (m/s)
CTG/HRSG, Acute Impacts (Case 1)	6.706	45.720	358.556	15.836
CTG/HRSG, Chronic and Cancer Impacts (Case 5)	6.706	45.720	359.667	14.491
Auxiliary Boiler	0.762	19.812	421.889	11.186

APPENDIX 5.1E

Construction Emissions and Impact Analysis

5.1E.1 Onsite Construction

The initial construction of the LEC is expected to last approximately 24 months. Construction activities will occur in the following main phases:

Site preparation;

Foundation work;

Installation of major equipment; and

Construction/installation of major structures.

5.1E.1.1 Construction Activities

The construction of LEC will begin with site preparation activities, which include installation of drainage systems, underground utilities and conduits, grading and backfilling operations, and installation of pilings. After site preparation is finished, the construction of the foundations and structures is expected to begin. Once the foundations and structures are finished, installation and assembly of the mechanical and electrical equipment are scheduled to commence.

Fugitive dust emissions from the construction of the project will result from:

- Dust entrained during site preparation and grading/excavation at the construction site;
- Dust entrained during onsite travel on paved and unpaved surfaces;
- Dust entrained during aggregate and soil loading and unloading operations; and
- Wind erosion of areas disturbed during construction activities.
- Combustion emissions during construction will result from:
- Exhaust from the diesel construction equipment used for site preparation, grading, excavation, trenching, and construction of onsite structures;
- Exhaust from water trucks used to control construction dust emissions;
- Exhaust from portable welding machines;
- Exhaust from pickup trucks and diesel trucks used to transport workers and materials around the construction site;
- Exhaust from diesel trucks used to deliver concrete, fuel, and construction supplies to the construction site; and

- Exhaust from automobiles used by workers to commute to the construction site.

To determine the potential worst-case daily construction impacts, exhaust and dust emission rates have been evaluated for each source of emissions. Maximum short-term impacts are calculated based on the equipment mix expected during Month 16 of the construction schedule.[1] Annual emissions are based on the average equipment mix during the peak 12-month period out of the overall 24-month construction period.

5.1E.1.2 Linear Facilities

The linear facilities that will be constructed for the proposed project include a new recycled water pipeline that will be constructed in the utility corridor that links the power plant with the adjacent water treatment plant and a 2.5 mile long natural gas pipeline. These linears will be constructed prior to or simultaneously with the construction of the project.

5.1E.2 Available Mitigation Measures

The following typical mitigation measures are proposed to control exhaust emissions from the diesel heavy equipment and potential emissions of fugitive dust during construction of the project.

- Unpaved roads and disturbed areas in the project construction site will be watered as frequently as necessary to prevent fugitive dust plumes. The frequency of watering can be reduced or eliminated during periods of precipitation.
- The vehicle speed limit will be 15 miles per hour within the construction site.
- The construction site entrances shall be posted with visible speed limit signs.
- Construction equipment vehicle tires will be inspected and washed as necessary to be cleaned free of dirt prior to entering paved roadways.
- Gravel ramps of at least 20 feet in length will be provided at the tire washing/cleaning station.
- Unpaved exits from the construction site will be graveled or treated to prevent track-out to public roadways.
- Construction vehicles will enter the construction site through the treated entrance roadways, unless an alternative route has been submitted to and approved by the Compliance Project Manager.
- Construction areas adjacent to any paved roadway will be provided with sandbags or other measures as specified in the Storm Water Pollution Prevention Plan (SWPPP) to prevent run-off to roadways.
- Paved roads within the construction site will be swept at least twice daily (or less during periods of precipitation) on days when construction activity occurs to prevent the accumulation of dirt and debris.

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[1] See calculations in Attachment 5.1E-1.

- At least the first 500 feet of any public roadway exiting from the construction site shall be swept at least twice daily (or less during periods of precipitation) on days when construction activity occurs or on any other day when dirt or runoff from the construction site is visible on public roadways.
- Soil storage piles and disturbed areas that remain inactive for longer than 10 days will be covered or treated with appropriate dust suppressant compounds.
- Vehicles used to transport solid bulk material on public roadways and having the potential to cause visible emissions will be provided with a cover, or the materials will be sufficiently wetted and loaded onto the trucks in a manner to provide at least one foot of freeboard.
- Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) will be used on all construction areas that may be disturbed. Any windbreaks installed to comply with this condition shall remain in place until the soil is stabilized or permanently covered with vegetation.

An on-site Air Quality Construction Mitigation Manager will be responsible for directing and documenting compliance with construction-related mitigation conditions.

5.1E.3 Estimates of Emissions with Mitigation Measures - Onsite Construction

Tables 5.1E-1 and 5.1E-2 show the estimated maximum daily and annual heavy equipment exhaust and fugitive dust emissions with recommended mitigation measures for onsite construction activities. Detailed emission calculations are included as Attachment 5.1E-1.

TABLE 5.1E-1
Maximum Daily Emissions During Construction, Pounds Per Day

	NOx	CO	VOC	SOx	PM_{10}	$PM_{2.5}$
Onsite						
Construction Equipment	80.6	51.4	7.7	0.1	4.5	4.5
Fugitive Dust	--	--	--	--	21.0	4.9
Offsite						
Worker Travel, Truck	80.6	51.4	7.7	0.1	4.5	4.5
Deliveries[a]	--	--	--	--	21.0	4.9
Total Emissions						
Total	260.1	238.6	32.7	0.4	33.5	17.5

Note:
a. Offsite emissions.

TABLE 5.1E-2
Peak Annual Emissions During Project Construction, Tons Per Year

TABLE 5.1E-2
Peak Annual Emissions During Project Construction, Tons Per Year

	NOx	CO	VOC	SOx	PM_{10}	$PM_{2.5}$
Onsite						
Construction Equipment	7.2	4.6	0.7	0.01	0.4	0.4
Fugitive Dust	--	--	--	--	1.6	0.3
Offsite						
Worker Travel, Truck Deliveries [a]	2.3	17.7	1.7	0.02	0.2	0.2
Total Emissions						
Total	9.5	22.4	2.4	0.03	2.2	0.9

Note:
a. Offsite emissions.

5.1E.4 Analysis of Ambient Impacts from Onsite Construction

Ambient air quality impacts from emissions during construction of the project were estimated using an air quality dispersion modeling analysis. The modeling analysis considers the construction site location, the surrounding topography, and the sources of emissions during construction, including vehicle and equipment exhaust emissions and fugitive dust.

5.1E.4.1 Existing Ambient Levels

As with the modeling analysis of project operating impacts (Section 5.1.5), ambient monitoring data collected from monitoring stations in the project area were used to establish the ambient background levels for the construction impact modeling analysis. Table 5.1E-3 shows the maximum concentrations of NOx, SO_2, CO, and PM_{10} recorded for 2005 through 2007.

TABLE 5.1E-3
Modeled Background Concentrations in the Project Area

Pollutant	Averaging Prd	2005	2006	2007
NO_2	1 hour	163.6	135.4	131.6
	annual	32.1	34.0	30.2
SO_2	1 hour	46.8	23.4	44.2
	3 hour	15.6	13.0	28.6
	24 hour	7.9	7.9	10.8
	annual	2.7	2.7	2.7
CO	1 hour	5,375	5,500	4,500
	8 hour	3,178	2,500	2,567

TABLE 5.1E-3
Modeled Background Concentrations in the Project Area

Pollutant	Averaging Prd	2005	2006	2007
PM_{10}	24 hour	84	85	75
	annual	29.4	33.4	27.7
$PM_{2.5}$[a]	24 hour	44	42	48
	annual	12.5	13.1	12.9

a. 24-hour average $PM_{2.5}$ concentrations shown are 98th percentile values, based on the form of the standard.

5.1E.4.2 Dispersion Model

The EPA guideline AERMOD model was used to estimate ambient impacts from construction activities.

The emission sources for the construction site were grouped into three categories: exhaust emissions, construction dust emissions, and windblown dust emissions. The exhaust and construction dust emissions were modeled as volume sources with a vertical dimension of 6 meters. Construction dust sources were modeled as 11 volume sources in the project site area. Combustion exhaust sources were allocated to the project site area as well as to the laydown and parking areas where construction equipment activity will also occur. The horizontal dimension of each volume source was set to 65 meters, with sigma-y = 15.116 meters (based on the width of the construction area). The windblown dust emissions were modeled as area sources. For these windblown dust sources, the area covers the active construction area. An effective plume height of 0.5 meters was used in the modeling analysis.

The construction impacts modeling analysis receptor set excluded the areas under the applicant's control, including the existing NCPA property and the laydown and parking areas that will be fenced and used for equipment and worker vehicles during the construction period.

To determine the construction impacts on short-term ambient standards (24 hours and less), the worst-case daily onsite construction emission levels shown in Table 5.1E-1 were used. For pollutants with annual average ambient standards, the annual onsite emission levels shown in Table 5.1E-2 were used.

As with the refined modeling discussed in Section 5.1, the construction impact modeling was performed using the 2000 to 2004 Stockton monitoring station meteorological data set.

5.1E.4.3 Modeling Results

Based on the emission rates of NOx, SO_2, CO, and PM_{10} and the meteorological data, the AERMOD model calculates hourly and annual ambient impacts for each pollutant. As mentioned above, the modeled 1-hour, 3-hour, 8-hour, and 24-hour ambient impacts are based on the worst-case daily emission rates of NOx, SO_2, CO, and PM_{10}. The annual impacts are based on the annual emission rates of these pollutants.

The 1-hour and annual average concentrations of NO_2 were computed following the revised EPA guidance for computing these concentrations (August 9, 1995 *Federal Register,* 60 FR 40465). The OLM method was used for the 1-hour average NO_2 impacts; uncorrected 1-hour impacts are also reported for comparison. The annual average was calculated using the ambient ratio method (ARM) with the national default value of 0.75 for the annual average NO_2/NOx ratio.

The modeling analysis results are shown in Table 5.1E-4. Also included in the table are the maximum background levels that have occurred in the last 3 years and the resulting total ambient impacts. Construction impacts alone for all modeled pollutants are expected to be below the most stringent state and national standards. With the exception of the 24-hour and annual average PM_{10} standards, construction activities are not expected to cause an exceedance of state or federal ambient air quality standards. However, the state 24-hour and annual PM_{10} standards are exceeded in the absence of the construction emissions for the project.

The dust mitigation measures already proposed by the applicant are expected to be effective in minimizing fugitive dust emissions. The attached isopleth diagrams show the extent of the modeled impacts from construction PM_{10} for the 24-hour and annual averaging periods.

TABLE 5.1E-4
Modeled Maximum Onsite Construction Impacts

Pollutant	Averaging Time	Maximum Onsite Construction Impact (µg/m^3)	Background (µg/m^3)	Total Impact (µg/m^3)	State Standard (µg/m^3)	Federal Standard (µg/m^3)
NO_2[a]	1-hour	91.6	163.6	255	338	–
	Annual	3.6	34.0	38	–	100
SO_2	1-hour	0.4	46.8	47	650	–
	3-hour	0.3	28.6	29	–	1300
	24-hour	0.1	10.8	11	109	365
	Annual	0.01	2.7	2.7	–	80
CO	1-hour	210	5,500	5,710	23,000	40,000
	8-hour	94	3,178	3,272	10,000	10,000
PM_{10}[b]	24-hour	35.6	85	121	50	150
	Annual	4.2	33.4	37.6	20	--
$PM_{2.5}$[b]	24-Hour	10.2	48	58	–	35
	Annual	1.1	13.1	14.2	12	15

TABLE 5.1E-4
Modeled Maximum Onsite Construction Impacts

Pollutant	Averaging Time	Maximum Onsite Construction Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	State Standard ($\mu g/m^3$)	Federal Standard ($\mu g/m^3$)

Notes:

a. Ozone limiting method applied for 1-hour average, using concurrent O_3 data. ARM applied for annual average, using national default 0.75 ratio.

b. PM_{10} and $PM_{2.5}$ impacts shown are from fugitive dust as well as combustion sources. Annual average $PM_{2.5}/PM_{10}$ impact from combustion sources only is 0.45 $\mu g/m^3$.

As shown on these isopleth diagrams, maximum impacts occur on the project site fenceline, and concentrations decrease rapidly within a couple of hundred meters of the project site. For example, maximum modeled 24-hour average PM_{10} impacts along the fenceline are approximately 36 $\mu g/m^3$. However, impacts are reduced by half within tens of meters from the facility fenceline. Maximum impacts are reduced to 10 $\mu g/m^3$ or less at the freeway.

It is also important to note that emissions in an exhaust plume are dispersed through the entrainment of ambient air, which dilutes the concentration of the emissions as they are carried away from the source by winds. The process of mixing the pollutants with greater and greater volumes of cleaner air is controlled primarily by the turbulence in the atmosphere. This dispersion occurs both horizontally, as the exhaust plume rises above the emission point, and vertically, as winds carry the plume horizontally away from its source.

The rise of a plume above its initial point of release is a significant contributing factor to the reductions in ground-level concentrations, both because a rising plume entrains more ambient air as it travels downwind, and because it travels farther downwind (and thus also undergoes more horizontal dispersion) before it impacts the ground. Vertical plume rise occurs as a result of buoyancy (plume is hotter than ambient air, and hot air, being less dense, tends to rise) and/or momentum (plume has an initial vertical velocity).

In AERMOD, area sources are not considered to have either buoyant or momentum plume rise, and therefore the model assumes that there is no vertical dispersion taking place. Thus a significant source of plume dilution is ignored when sources are modeled as area sources. The project construction site impacts are not unusual in comparison to most construction project analyses. Construction sites that use good dust suppression techniques and low-emitting vehicles typically do not cause exceedances of air quality standards. The input and output modeling files are being provided electronically.

5.1E.4.4 Health Risk of Diesel Exhaust

The combustion portion of annual PM_{10} emissions from Table 5.1E-5 above was modeled separately to determine the annual average Diesel PM_{10} exhaust concentration. This was used with HARP-derived risk values for Diesel exhaust particulate[2] for a 9-year exposure to determine the potential carcinogenic risk from Diesel exhaust during construction.[3]

The maximum modeled annual average concentration of Diesel exhaust PM_{10} at any location is 0.45 µg/m^3. The cancer risk value obtained from HARP is 4.15x10^{-4} (derived OEHHA method). Adjusting the risk value by 9/70 to reflect a 9-year exposure yields an adjusted risk value of 5.34x10^{-5}. Using the risk value and adjustment factors described above, the carcinogenic risk due to exposure to Diesel exhaust during construction activities is expected to be approximately 24 in one million. This risk estimate is above the significance level of 10 in one million. However, these impacts are highly localized near the project site. As shown in the attached annual average Diesel combustion PM_{10} isopleth diagram (Figure 5.1E-3), the area in which the risk may exceed 10 in one million (Diesel PM_{10} impact greater than or equal to approximately 0.2 µg/m^3) barely extends l beyond the construction and laydown/parking areas and does not include any residences or sensitive receptors. This analysis remains conservative because, as discussed above, the modeled PM_{10} concentrations from construction operations are overpredicted by the AERMOD model.

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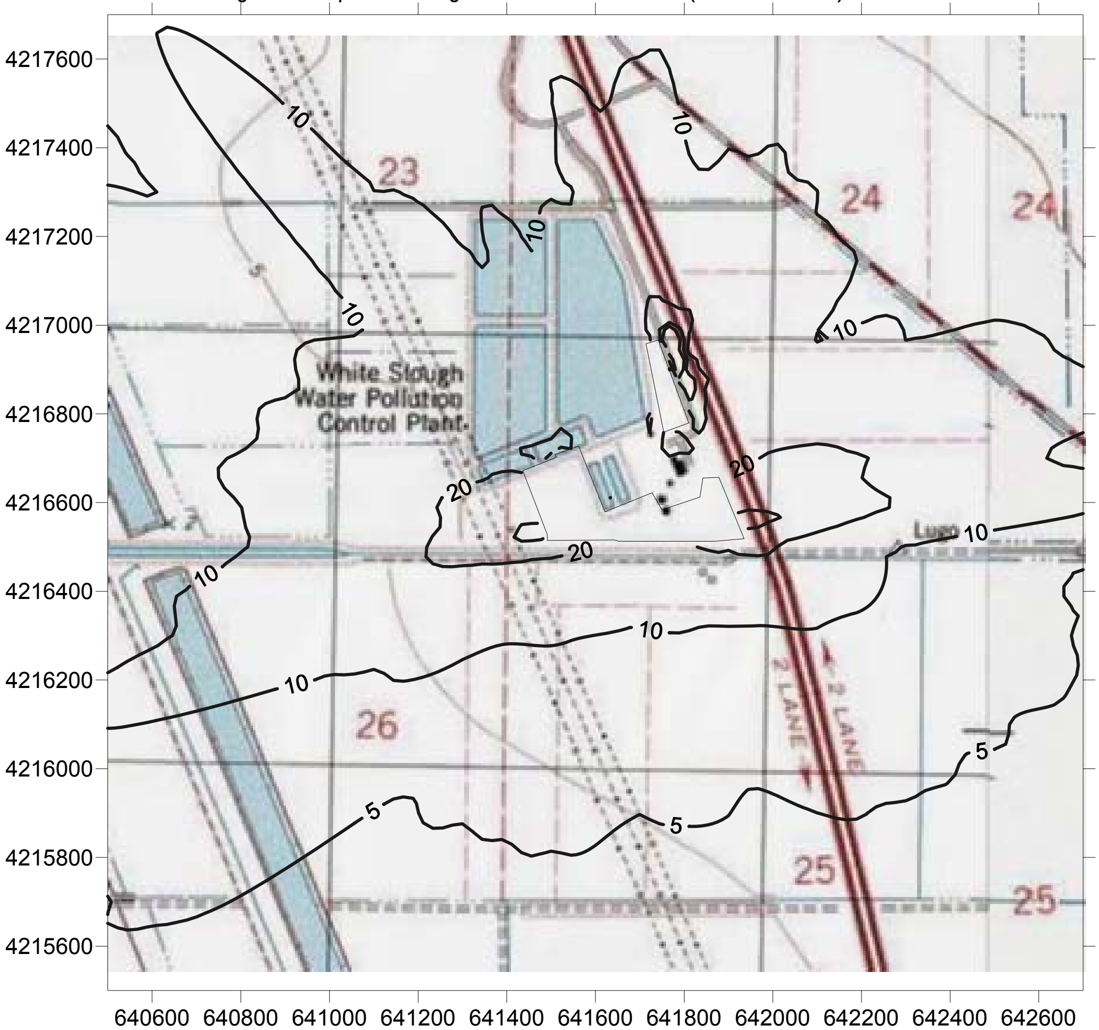
2 See Section 5.1.2.8 for a discussion of the use of the HARP model to derive cancer risk values.

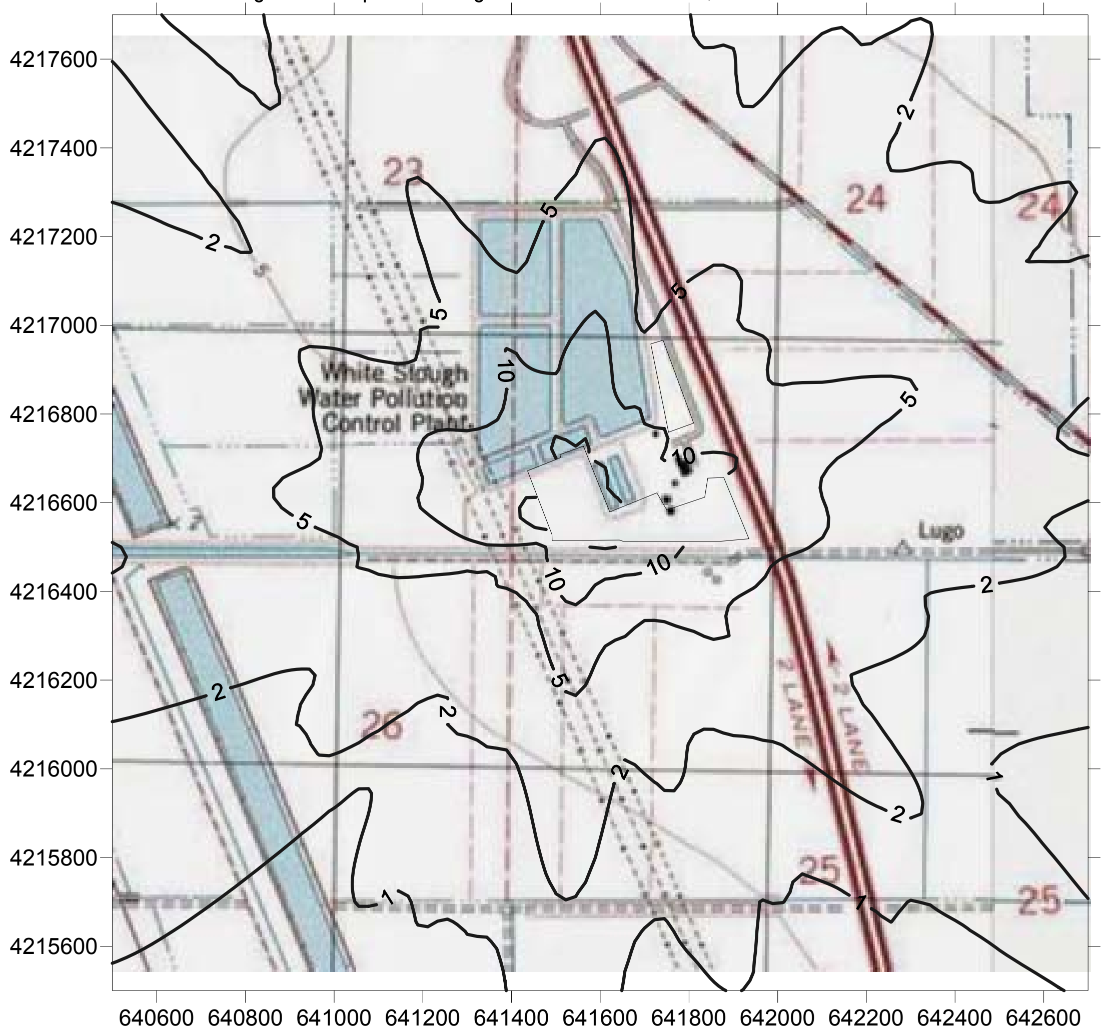
3 OEHHA, "Adoption of Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments," 10/03/03, accessed at http://www.oehha.ca.gov/air/hot_spots/HRAguidefinal.html

FIGURE 5.1E-1
Maximum 1-Hour Average NO_2 Impacts During Construction Activities (Ozone-Limited)



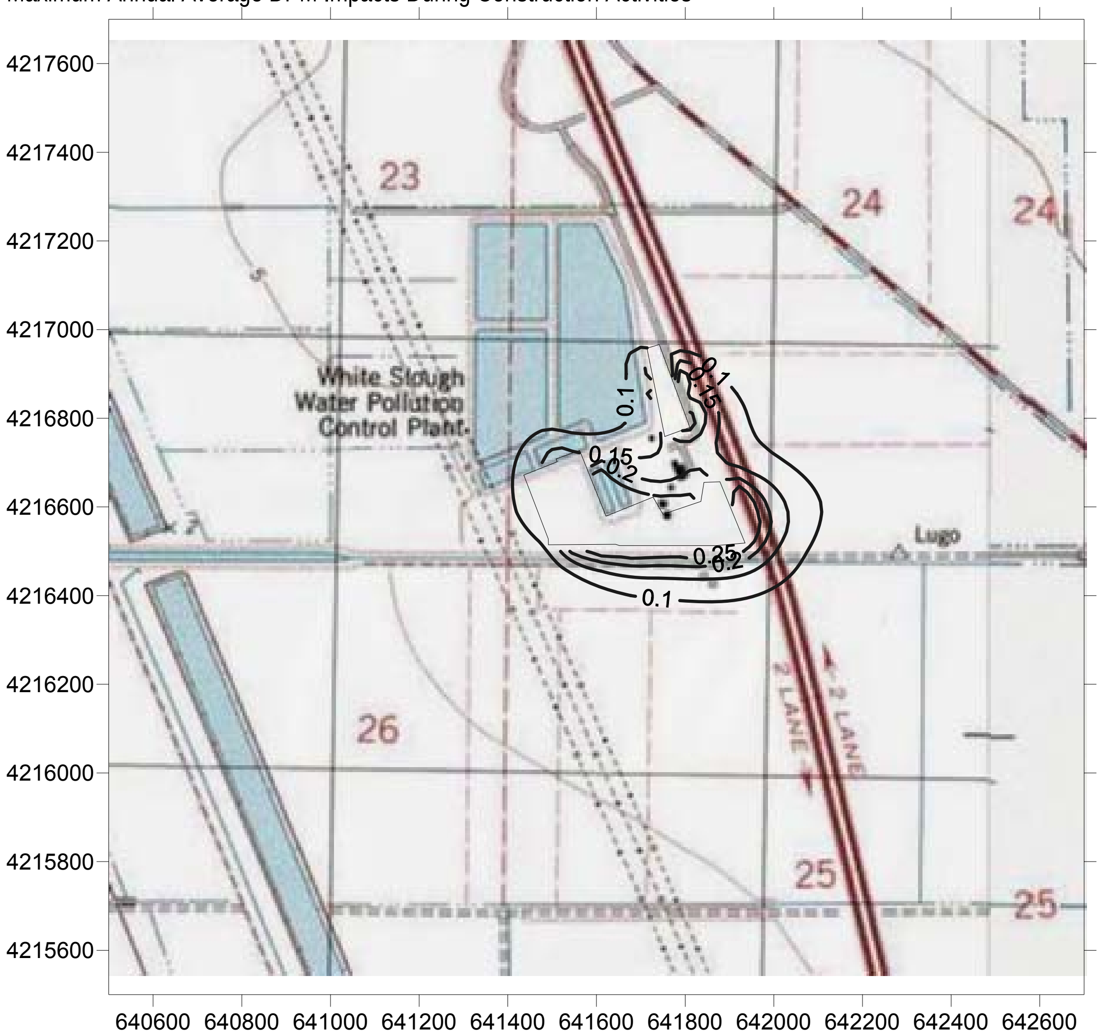
Concentrations are shown in $\mu g/m^3$.

FIGURE 5.1E-2
Maximum 24-Hour Average PM_{10} Impacts During Construction Activities, All Sources



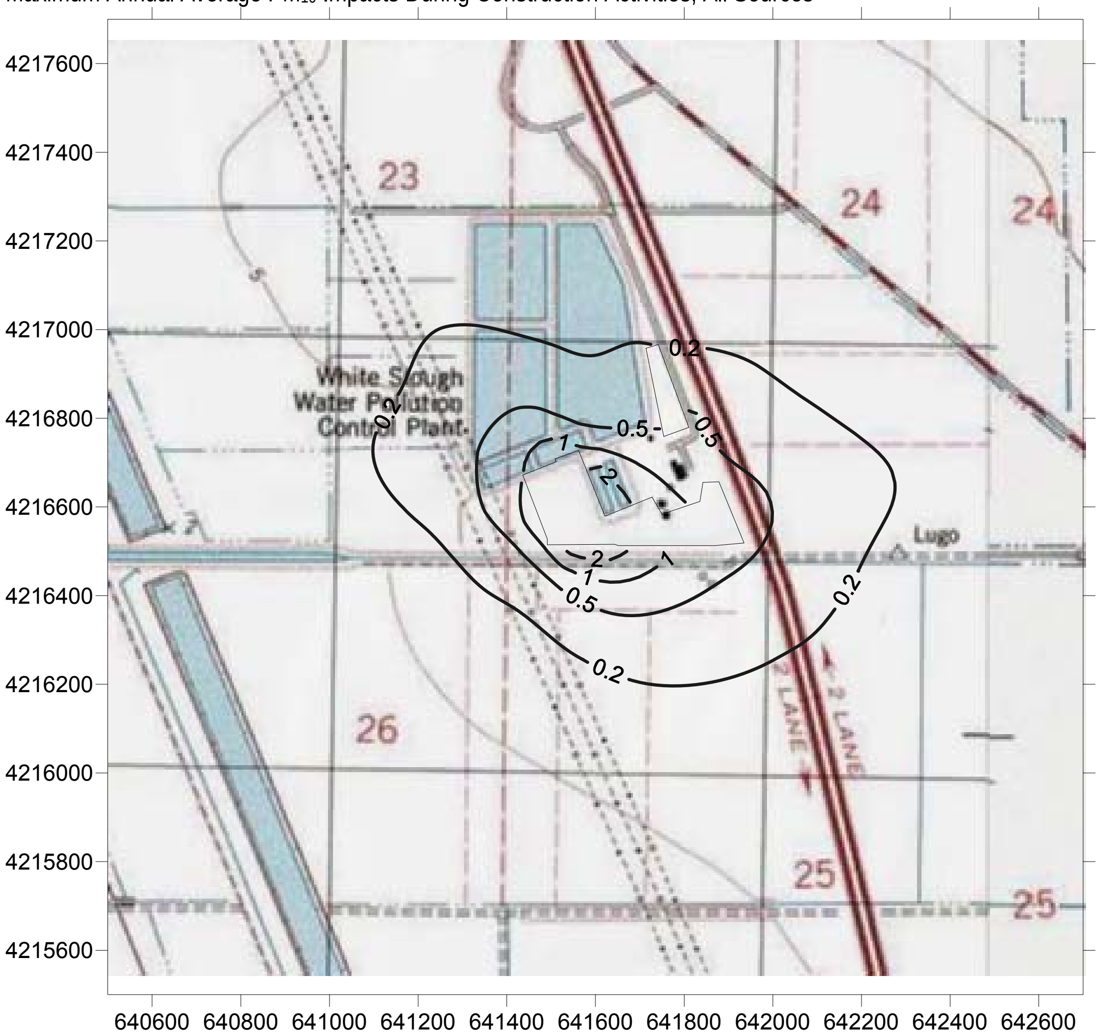
Concentrations are shown in $\mu g/m^3$.

FIGURE 5.1E-3
Maximum Annual Average DPM Impacts During Construction Activities



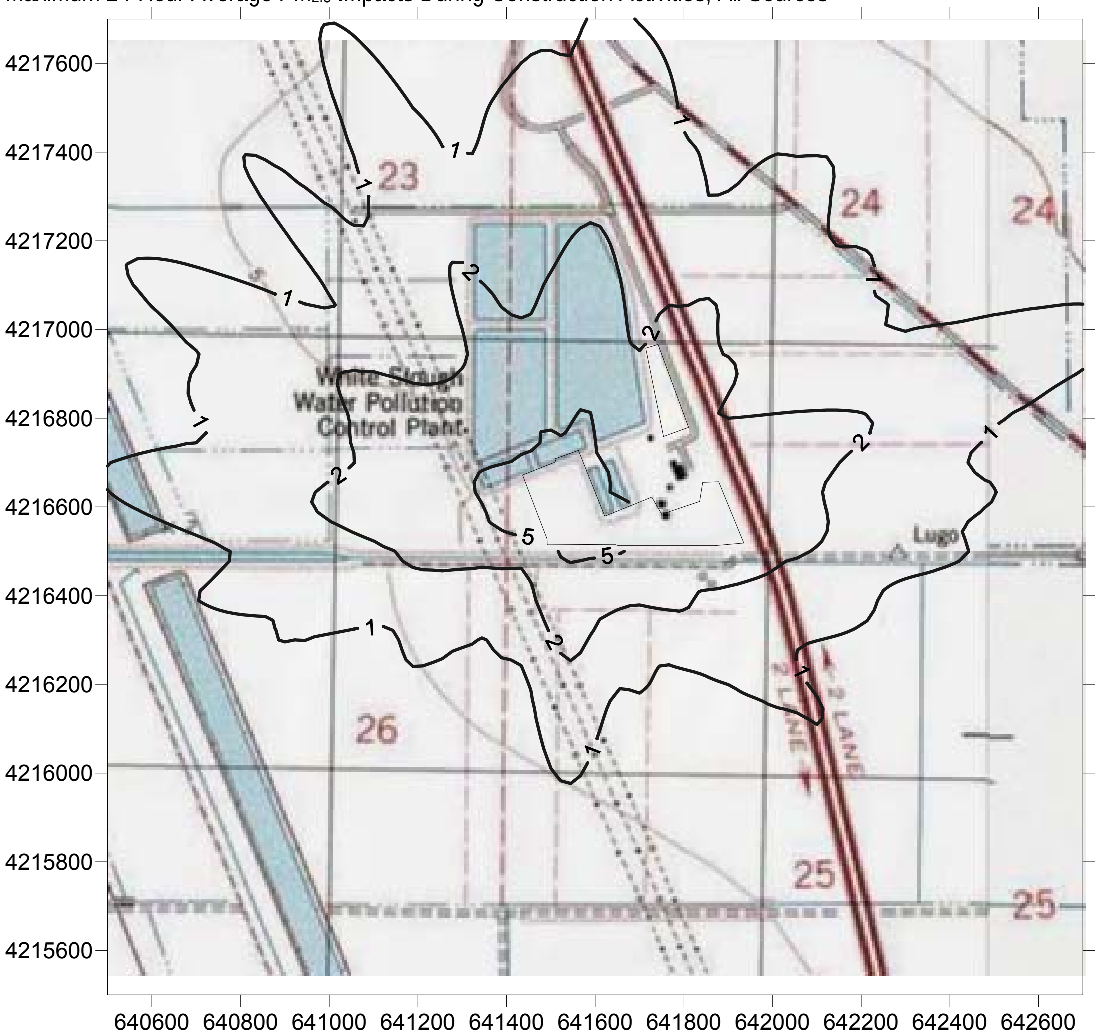
Concentrations are shown in $\mu g/m^3$.

FIGURE 5.1E-4
Maximum Annual Average PM_{10} Impacts During Construction Activities, All Sources



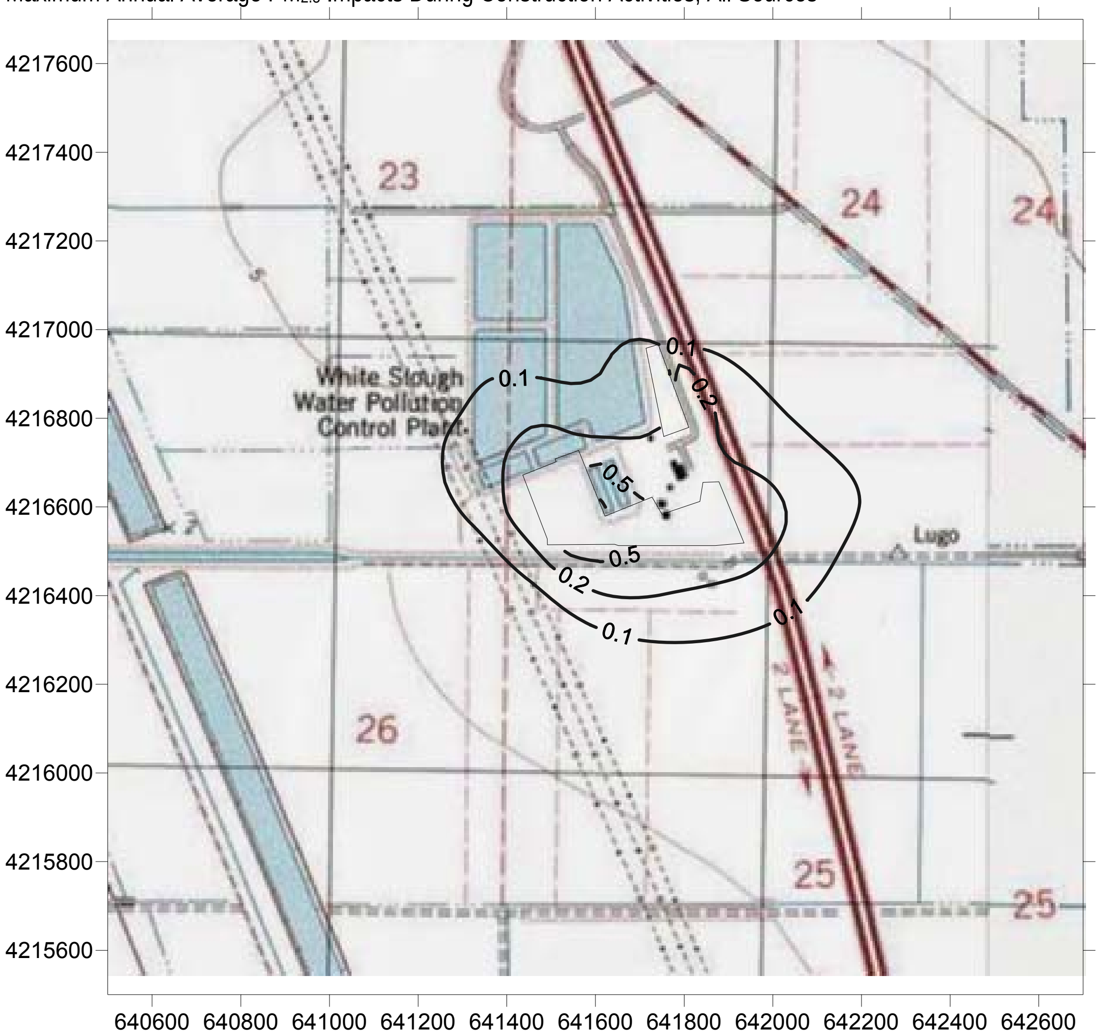
Concentrations are shown in $\mu g/m^3$.

FIGURE 5.1E-5
Maximum 24-Hour Average $PM_{2.5}$ Impacts During Construction Activities, All Sources



Concentrations are shown in $\mu g/m^3$.

FIGURE 5.1E-6
Maximum Annual Average $PM_{2.5}$ Impacts During Construction Activities, All Sources



Concentrations are shown in $\mu g/m^3$.

Attachment 5.1E-1
Detailed Construction Emissions Calculations

Daily and Annual Construction Emissions

Daily Construction Emissions (peak month) (lbs/day)						
	NOx	CO	VOC	SOx	PM2.5	PM10
Onsite						
Construction Equipment	80.61	51.42	7.72	0.10	4.46	4.46
Fugitive Dust					4.94	21.01
Subtotal =	80.61	51.42	7.72	0.10	9.40	25.47
Offsite						
Worker Travel	12.07	125.61	11.91	0.11	1.16	1.16
Truck Deliveries	167.46	61.55	13.01	0.14	6.90	6.90
Subtotal =	179.52	187.16	24.92	0.26	8.06	8.06
Total =	260.13	238.58	32.65	0.36	17.47	33.53

Peak Annual Construction Emissions (12-month period) (tons/yr)						
	NOx	CO	VOC	SOx	PM2.5	PM10
Onsite						
Construction Equipment	7.22	4.64	0.71	0.01	0.41	0.41
Fugitive Dust					0.27	1.61
Subtotal =	7.22	4.64	0.71	0.01	0.68	2.02
Offsite						
Worker Travel	1.68	17.50	1.66	0.02	0.16	0.16
Truck Deliveries	0.58	0.21	0.05	0.00	0.02	0.02
Subtotal =	2.27	17.71	1.70	0.02	0.19	0.19
Total =	9.49	22.35	2.42	0.03	0.87	2.21

LEC Construction Equipment Schedule

					1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Pile driving equipment, 255 HP	100%	8 hr/day	6 days/week	48 hrs/week	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Roller Compactor, 100 HP	100%	8 hr/day	6 days/week	48 hrs/week	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
Backhoe, 150 HP	100%	8 hr/day	6 days/week	48 hrs/week	1	2	2	2	2	3	3	3	3	3	3	2	2	2	2	2	2	1	1	1	1	1	1	1	46
Forklift, CAT V200, 175 HP	100%	8 hr/day	6 days/week	48 hrs/week	1	1	1	1	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	0	0	0	0	0	29
Bulldozer, 450G, 400 HP	100%	8 hr/day	6 days/week	48 hrs/week	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4
Motor Grader, 135 HP	100%	8 hr/day	6 days/week	48 hrs/week	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
Crane, pile lifting, 25 ton, 160 HP	100%	8 hr/day	6 days/week	48 hrs/week	0	0	0	0	0	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	0	0	0	0	25
Excavator, 195 HP	100%	8 hr/day	6 days/week	48 hrs/week	0	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9
Cranes, 230 ton, 220 HP	100%	8 hr/day	6 days/week	48 hrs/week	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	32
Cranes, 400 ton, 255 HP	100%	8 hr/day	6 days/week	48 hrs/week	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	9
Cranes, 15 ton, 101 HP	100%	8 hr/day	6 days/week	48 hrs/week	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	19
Manlift, 60ft, 30 HP	100%	8 hr/day	6 days/week	48 hrs/week	0	0	0	1	2	2	2	3	3	3	3	3	2	2	2	2	2	2	2	1	1	1	1	0	40
Scrapers, 550 HP	100%	8 hr/day	6 days/week	48 hrs/week	1	1	1	1	1	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	0	0	0	0	9
Water Truck, 225 HP	100%	8 hr/day	6 days/week	48 hrs/week	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	24
Welding Unit, 70 HP	100%	8 hr/day	6 days/week	48 hrs/week	0	1	1	3	3	3	3	3	3	3	3	3	3	3	3	2	2	2	1	1					46
Dump truck, 210 HP	100%	8 hr/day	6 days/week	48 hrs/week	2	2	2	2	2	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12
Boom truck, 220 HP	100%	8 hr/day	6 days/week	48 hrs/week	0	1	1	2	2	3	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	54
Tandem Dump Truck, 30 CY, 250 HP	100%	8 hr/day	6 days/week	48 hrs/week	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
Concrete pump truck, 350 HP	100%	8 hr/day	6 days/week	48 hrs/week	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Total vehicles					11	16	17	22	22	23	22	22	22	22	21	21	20	20	19	14	14	13	12	8	6	5	5	4	

Offsite Delivery Truck Emissions

Delivery Truck Daily Emissions (Maximum)													
Number of Deliveries Per Day	Average Round Trip Haul Distance (miles)	Vehicle Miles Traveled Per Day	Emission Factors (lbs/vmt)(1) NOx	CO	VOC	SOx	PM10	Daily Emissions (lbs/day) NOx	CO	VOC	SOx	PM10
88	49.8	4,382	0.0382	0.0140	0.0030	0.0000	0.0016	167.46	61.55	13.01	0.14	6.90
Idle exhaust (2)												0.32296

Delivery Truck Peak Annual Emissions												
Number of Deliveries Per Year	Average Round Trip Haul Distance (miles)	Vehicle Miles Traveled Per Year	Emission Factors (lbs/vmt)(1) NOx	CO	VOC	SOx	PM10	Annual Emissions (tons/yr) NOx	CO	VOC	SOx	PM10
614	49.8	30,577	0.0382	0.0140	0.0030	0.0000	0.0016	0.58	0.21	0.05	0.00	0.02
Idle exhaust (2,3)												0.00113

Notes:
(1) Emission factors for delivery trucks from Emfac2007 V2.3, San Joaquin County, model years 1966 to 2010.
(2) Peak annual number of trucks per year times 1 hr idle time per visit times 0.00367 lb/hr
(3) Based on 1.665 g/hr idle emission rate for the composite HDD truck fleet in 2010 from EMFAC2007 V2.3, San Joaquin County, 2010 fleet.

Offsite Worker Travel Emissions

Worker Travel Daily Emissions (Maximum)														
Number of Workers Per Day(1)	Average Vehicle Occupancy (person/veh.)	Number of Round Trips Per Day	Average Round Trip Distance (Miles)	Vehicle Miles Traveled Per Day (Miles)	Emission Factors (lbs/vmt)(1)					Daily Emissions (lbs/day)				
					NOx	CO	VOC	SOx	PM10	NOx	CO	VOC	SOx	PM10
302	1.1	272	49.8	13,536	0.0009	0.0093	0.0009	0.0000	0.0001	12.07	125.61	11.91	0.11	1.16

Worker Travel Peak Annual Emissions															
Average Number of Workers Per Day	Average Vehicle Occupancy (person/veh.)	Number of Round Trips Per Day	Average Round Trip Haul Distance (Miles)	Days per Year	Vehicle Miles Traveled Per Year	Emission Factors (lbs/vmt)(1)					Annual Emissions (tons/yr)				
						NOx	CO	VOC	SOx	PM10	NOx	CO	VOC	SOx	PM10
292	1.1	263	49.8	288	3,771,338	0.0009	0.0093	0.0009	0.0000	0.0001	1.68	17.50	1.66	0.02	0.16

Notes:
(1) Emission factors for worker travel from EMFAC2002, V2.2, San Diego County, model years 1965 to 2008.

Onsite Combustion Emissions

			Base Factors g/bhp, if Tier 1 >50 hp (1)						Appendix A Table A3 Adjustment (2)						Adjustment (3)	Adjusted Factors (g/bhp)					
Equipment	HP Cat.	Tier	BSFC lb/hp	NOx	CO	VOC	SOx	PM10	Adj. Type	NOx	CO	VOC	SOx	PM10	PM10 Fuel S	BSFC	NOx	CO	VOC	SOx	PM10
Pile driving equipment, 255 HP	175-300	3	0.367	2.50	0.75	0.18	0.005	0.15	None	1.10	1.00	1.00	1.00	1.00	-0.086	0.367	2.75	0.75	0.18	0.0049	0.06
Roller Compactor, 100 HP	75-100	2	0.408	4.70	2.37	0.37	0.006	0.24	Hi LF	0.95	1.53	1.05	1.01	1.23	-0.096	0.412	4.47	3.62	0.39	0.0055	0.20
Backhoe, 150 HP	100-175	3	0.367	2.50	0.87	0.18	0.005	0.22	Lo LF	1.21	2.57	2.29	1.18	2.37	-0.101	0.433	3.03	2.23	0.42	0.0057	0.42
Forklift, CAT V200, 175 HP	100-175	3	0.367	2.50	0.87	0.18	0.005	0.22	Hi LF	1.04	1.00	1.05	1.01	1.47	-0.087	0.371	2.60	0.87	0.19	0.0049	0.24
Bulldozer, 450G, 400 HP	300-600	3	0.367	2.50	0.84	0.17	0.005	0.15	Hi LF	1.04	1.00	1.05	1.01	1.47	-0.087	0.371	2.60	0.84	0.18	0.0049	0.13
Motor Grader, 135 HP	100-175	3	0.367	2.50	0.87	0.18	0.005	0.22	Hi LF	0.95	1.53	1.05	1.01	1.23	-0.087	0.371	2.38	1.33	0.19	0.0049	0.18
Crane, pile lifting, 25 ton, 160 HP	100-175	3	0.367	2.50	0.87	0.18	0.005	0.22	None	1.10	1.00	1.00	1.00	1.00	-0.086	0.367	2.75	0.87	0.18	0.0049	0.13
Excavator, 195 HP	175-300	3	0.367	2.50	0.75	0.18	0.005	0.15	Hi LF	1.04	1.00	1.05	1.01	1.47	-0.087	0.371	2.60	0.75	0.19	0.0049	0.13
Cranes, 230 ton, 220 HP	175-300	3	0.367	2.50	0.75	0.18	0.005	0.15	None	1.10	1.00	1.00	1.00	1.00	-0.086	0.367	2.75	0.75	0.18	0.0049	0.06
Cranes, 400 ton, 255 HP	175-300	3	0.367	2.50	0.75	0.18	0.005	0.15	None	1.10	1.00	1.00	1.00	1.00	-0.086	0.367	2.75	0.75	0.18	0.0049	0.06
Cranes, 15 ton, 101 HP	100-175	3	0.367	2.50	0.87	0.18	0.005	0.22	None	1.10	1.00	1.00	1.00	1.00	-0.086	0.367	2.75	0.87	0.18	0.0049	0.13
Manlift, 60ft, 30 HP	25-50	2	0.408	4.73	1.53	0.28	0.006	0.34	Lo LF	1.21	2.57	2.29	1.18	2.37	-0.113	0.481	5.72	3.94	0.64	0.0064	0.69
Scrapers, 550 HP	300-600	3	0.367	2.50	0.84	0.17	0.005	0.15	Hi LF	0.95	1.53	1.05	1.01	1.23	-0.087	0.371	2.38	1.29	0.18	0.0049	0.10
Water Truck, 225 HP	Onroad	na	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad
Welding Unit, 70 HP	50-75	2	0.408	4.44	2.16	0.44	0.0056	0.27	Hi LF	0.95	1.53	1.05	1.01	1.23	-0.096	0.412	4.22	3.31	0.46	0.0055	0.23
Dump truck, 210 HP	Onroad	na	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad
Boom truck, 220 HP	Onroad	na	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad
Tandem Dump Truck, 30 CY, 250 HP	Onroad	na	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad
Concrete pump truck, 350 HP	Onroad	na	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad	Onroad

		Adjusted factors lbs/1000 gallon (4)				
Equipment	Tier	NOx	CO	VOC	SOx	PM10
Pile driving equipment, 255 HP	3	117.29	31.88	7.83	0.21	2.74
Roller Compactor, 100 HP	2	169.60	137.47	14.65	0.21	7.55
Backhoe, 150 HP	3	109.34	80.51	15.20	0.21	15.19
Forklift, CAT V200, 175 HP	3	109.79	36.61	8.16	0.21	9.99
Bulldozer, 450G, 400 HP	3	109.79	35.60	7.40	0.21	5.65
Motor Grader, 135 HP	3	100.29	56.00	8.14	0.21	7.77
Crane, pile lifting, 25 ton, 160 HP	3	117.29	36.98	7.85	0.21	5.72
Excavator, 195 HP	3	109.79	31.57	8.14	0.21	5.65
Cranes, 230 ton, 220 HP	3	117.29	31.88	7.83	0.21	2.74
Cranes, 400 ton, 255 HP	2	117.29	31.88	7.83	0.21	2.74
Cranes, 15 ton, 101 HP	3	117.29	36.98	7.85	0.21	5.72
Manlift, 60ft, 30 HP	2	185.99	128.03	20.76	0.21	22.45
Scrapers, 550 HP	3	100.29	54.46	7.40	0.21	4.13
Water Truck, 225 HP	na	135.71	172.26	19.65	0.00	4.57
Welding Unit, 70 HP	2	160.21	125.59	17.47	0.21	8.79
Dump truck, 210 HP	na	135.71	172.26	19.65	0.00	4.57
Boom truck, 220 HP	na	135.71	172.26	19.65	0.00	4.57
Tandem Dump Truck, 30 CY, 250 HP	na	204.23	75.06	15.87	0.18	8.42
Concrete pump truck, 350 HP	na	204.23	75.06	15.87	0.18	8.42

Construction Equipment
Daily Fuel Use

Equipment	Hrs/Day Per Unit	Gals/Hr Per Unit	Daily Fuel Use (gals/day) Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9	Month 10	Month 11
Pile driving equipment, 255 HP	8.0	5.67	45.3	45.3	45.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Roller Compactor, 100 HP	8.0	2.50	20.0	20.0	20.0	20.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0
Backhoe, 150 HP	8.0	3.10	24.8	49.6	49.6	49.6	49.6	74.4	74.4	74.4	74.4	74.4	74.4
Forklift, CAT V200, 175 HP	8.0	2.50	20.0	20.0	20.0	20.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Bulldozer, 450G, 400 HP	8.0	9.70	77.6	77.6	77.6	77.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Motor Grader, 135 HP	8.0	3.30	26.4	26.4	26.4	26.4	26.4	26.4	0.0	0.0	0.0	0.0	0.0
Crane, pile lifting, 25 ton, 160 HP	8.0	3.56	0.0	0.0	0.0	0.0	0.0	56.9	56.9	56.9	56.9	56.9	56.9
Excavator, 195 HP	8.0	4.70	0.0	37.6	37.6	37.6	37.6	37.6	37.6	37.6	37.6	37.6	0.0
Cranes, 230 ton, 220 HP	8.0	4.89	0.0	0.0	0.0	78.2	78.2	78.2	78.2	78.2	78.2	78.2	78.2
Cranes, 400 ton, 255 HP	8.0	5.67	0.0	0.0	0.0	0.0	0.0	0.0	45.3	45.3	45.3	45.3	45.3
Cranes, 15 ton, 101 HP	8.0	2.24	0.0	0.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Manlift, 60ft, 30 HP	8.0	1.27	0.0	0.0	0.0	10.2	20.3	20.3	20.3	30.5	30.5	30.5	30.5
Scrapers, 550 HP	8.0	11.25	90.0	90.0	90.0	90.0	90.0	0.0	0.0	0.0	0.0	0.0	0.0
Water Truck, 225 HP	8.0	3.13	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Welding Unit, 70 HP	8.0	1.27	0.0	10.2	10.2	30.5	30.5	30.5	30.5	30.5	30.5	30.5	30.5
Dump truck, 210 HP	8.0	3.13	50.1	50.1	50.1	50.1	50.1	25.0	25.0	0.0	0.0	0.0	0.0
Boom truck, 220 HP	8.0	3.13	0.0	25.0	25.0	50.1	50.1	75.1	75.1	75.1	75.1	75.1	75.1
Tandem Dump Truck, 30 CY, 250	8.0	3.13	25.0	25.0	25.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	0.0
Concrete pump truck, 350 HP	8.0	3.13	0.0	25.0	25.0	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total =			404.3	526.9	544.9	633.3	560.8	532.5	526.4	511.6	511.6	511.6	474.0

Construction Equipment
Daily Fuel Use

Equipment	Month 12	Month 13	Month 14	Month 15	Month 16	Month 17	Month 18	Month 19	Month 20	Month 21	Month 22	Month 23	Month 24
Pile driving equipment, 255 HP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Roller Compactor, 100 HP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Backhoe, 150 HP	49.6	49.6	49.6	49.6	49.6	49.6	24.8	24.8	24.8	24.8	24.8	24.8	24.8
Forklift, CAT V200, 175 HP	40.0	40.0	40.0	20.0	20.0	20.0	20.0	20.0	0.0	0.0	0.0	0.0	0.0
Bulldozer, 450G, 400 HP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Motor Grader, 135 HP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Crane, pile lifting, 25 ton, 160 HP	56.9	56.9	56.9	56.9	28.5	28.5	28.5	28.5	28.5	0.0	0.0	0.0	0.0
Excavator, 195 HP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cranes, 230 ton, 220 HP	78.2	78.2	78.2	78.2	78.2	78.2	78.2	78.2	0.0	0.0	0.0	0.0	0.0
Cranes, 400 ton, 255 HP	45.3	45.3	45.3	45.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cranes, 15 ton, 101 HP	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	0.0	0.0	0.0
Manlift, 60ft, 30 HP	30.5	20.3	20.3	20.3	20.3	20.3	20.3	20.3	10.2	10.2	10.2	10.2	0.0
Scrapers, 550 HP	90.0	90.0	90.0	90.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Water Truck, 225 HP	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Welding Unit, 70 HP	30.5	30.5	30.5	30.5	20.3	20.3	20.3	10.2	10.2	0.0	0.0	0.0	0.0
Dump truck, 210 HP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Boom truck, 220 HP	75.1	75.1	75.1	75.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1
Tandem Dump Truck, 30 CY, 250	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Concrete pump truck, 350 HP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total =	539.2	529.0	529.0	509.0	310.0	310.0	285.2	275.0	166.6	128.0	110.1	110.1	99.9

Equipment	Daily NOx Emissions (lbs/day) Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9	Month 10	Month 11	Month 12	Month 13	Month 14	Month 15	Month 16	Month 17	Month 18	Month 19	Month 20	Month 21	Month 22	Month 23	Month 24
Pile driving equipment, 255 HP	5.32	5.32	5.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Roller Compactor, 100 HP	3.39	3.39	3.39	3.39	3.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Backhoe, 150 HP	2.71	5.42	5.42	5.42	5.42	8.13	8.13	8.13	8.13	8.13	8.13	5.42	5.42	5.42	5.42	5.42	5.42	2.71	2.71	2.71	2.71	2.71	2.71	2.71
Forklift, CAT V200, 175 HP	2.20	2.20	2.20	2.20	4.39	4.39	4.39	4.39	4.39	4.39	4.39	4.39	4.39	4.39	2.20	2.20	2.20	2.20	2.20	0.00	0.00	0.00	0.00	0.00
Bulldozer, 450G, 400 HP	8.52	8.52	8.52	8.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor Grader, 135 HP	2.65	2.65	2.65	2.65	2.65	2.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Crane, pile lifting, 25 ton, 160 HP	0.00	0.00	0.00	0.00	0.00	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	6.67	3.34	3.34	3.34	3.34	3.34	0.00	0.00	0.00	0.00
Excavator, 195 HP	0.00	4.13	4.13	4.13	4.13	4.13	4.13	4.13	4.13	4.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cranes, 230 ton, 220 HP	0.00	0.00	0.00	9.18	9.18	9.18	9.18	9.18	9.18	9.18	9.18	9.18	9.18	9.18	9.18	9.18	9.18	9.18	9.18	0.00	0.00	0.00	0.00	0.00
Cranes, 400 ton, 255 HP	0.00	0.00	0.00	0.00	0.00	0.00	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cranes, 15 ton, 101 HP	0.00	0.00	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	2.11	0.00	0.00	0.00
Manlift, 60ft, 30 HP	0.00	0.00	0.00	1.89	3.78	3.78	3.78	5.67	5.67	5.67	5.67	5.67	3.78	3.78	3.78	3.78	3.78	3.78	3.78	1.89	1.89	1.89	1.89	0.00
Scrapers, 550 HP	9.03	9.03	9.03	9.03	9.03	0.00	0.00	0.00	0.00	0.00	0.00	9.03	9.03	9.03	9.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Truck, 225 HP	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40	3.40
Welding Unit, 70 HP	0.00	1.63	1.63	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	3.26	3.26	3.26	1.63	1.63	0.00	0.00	0.00	0.00
Dump truck, 210 HP	6.80	6.80	6.80	6.80	6.80	3.40	3.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Boom truck, 220 HP	0.00	3.40	3.40	6.80	6.80	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	10.19	6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.80
Tandem Dump Truck, 30 CY, 250 HP	5.11	5.11	5.11	5.11	5.11	5.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Concrete pump truck, 350 HP	0.00	5.11	5.11	5.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total =	49.12	66.10	68.21	**80.61**	71.06	68.03	65.58	64.07	64.07	64.07	59.95	66.26	64.37	64.37	62.18	39.47	39.47	36.76	35.13	21.87	16.90	14.80	14.80	12.91
Monthly Emissions (lbs/month) =	884	1,190	1,228	1,451	1,279	1,224	1,180	1,153	1,153	1,153	1,079	1,193	1,159	1,159	1,119	710	710	662	632	394	304	266	266	232
Annual Emissions (lbs/year) =												14,168	**14,443**	14,412	14,303	13,563	12,994	12,431	11,883	11,123	10,274	9,387	8,574	7,614
Annual Emissions (tons/year) =												7.08	**7.22**	7.21	7.15	6.78	6.50	6.22	5.94	5.56	5.14	4.69	4.29	3.81

Equipment	Daily CO Emissions (lbs/day) Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9	Month 10	Month 11	Month 12	Month 13	Month 14	Month 15	Month 16	Month 17	Month 18	Month 19	Month 20	Month 21	Month 22	Month 23	Month 24
Pile driving equipment, 255 HP	1.45	1.45	1.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Roller Compactor, 100 HP	2.75	2.75	2.75	2.75	2.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Backhoe, 150 HP	2.00	3.99	3.99	3.99	3.99	5.99	5.99	5.99	5.99	5.99	5.99	3.99	3.99	3.99	3.99	3.99	3.99	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Forklift, CAT V200, 175 HP	0.73	0.73	0.73	0.73	1.46	1.46	1.46	1.46	1.46	1.46	1.46	1.46	1.46	1.46	0.73	0.73	0.73	0.73	0.73	0.00	0.00	0.00	0.00	0.00
Bulldozer, 450G, 400 HP	2.76	2.76	2.76	2.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor Grader, 135 HP	1.48	1.48	1.48	1.48	1.48	1.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Crane, pile lifting, 25 ton, 160 HP	0.00	0.00	0.00	0.00	0.00	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	1.05	1.05	1.05	1.05	1.05	0.00	0.00	0.00	0.00
Excavator, 195 HP	0.00	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cranes, 230 ton, 220 HP	0.00	0.00	0.00	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	0.00	0.00	0.00	0.00	0.00
Cranes, 400 ton, 255 HP	0.00	0.00	0.00	0.00	0.00	0.00	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cranes, 15 ton, 101 HP	0.00	0.00	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.66	0.00	0.00	0.00
Manlift, 60ft, 30 HP	0.00	0.00	0.00	1.30	2.60	2.60	2.60	3.90	3.90	3.90	3.90	3.90	2.60	2.60	2.60	2.60	2.60	2.60	2.60	1.30	1.30	1.30	1.30	0.00
Scrapers, 550 HP	4.90	4.90	4.90	4.90	4.90	0.00	0.00	0.00	0.00	0.00	0.00	4.90	4.90	4.90	4.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Truck, 225 HP	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31	4.31
Welding Unit, 70 HP	0.00	1.28	1.28	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	3.83	2.55	2.55	2.55	1.28	1.28	0.00	0.00	0.00	0.00
Dump truck, 210 HP	8.63	8.63	8.63	8.63	8.63	4.31	4.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Boom truck, 220 HP	0.00	4.31	4.31	8.63	8.63	12.94	12.94	12.94	12.94	12.94	12.94	12.94	12.94	12.94	12.94	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63	8.63
Tandem Dump Truck, 30 CY, 250 HP	1.88	1.88	1.88	1.88	1.88	1.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Concrete pump truck, 350 HP	0.00	1.88	1.88	1.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total =	30.89	41.54	42.20	**51.42**	48.81	45.26	43.35	40.33	40.33	40.33	39.15	42.05	40.75	40.75	40.02	27.03	27.03	25.03	23.76	19.23	16.90	16.24	16.24	14.94
Monthly Emissions (lbs/month) =	556	748	760	926	879	815	780	726	726	726	705	757	734	734	720	487	487	451	428	346	304	292	292	269
Annual Emissions (lbs/year) =												9,102	**9,279**	9,265	9,226	8,787	8,395	8,031	7,678	7,298	6,877	6,443	6,031	5,542
Annual Emissions (tons/year) =												4.55	**4.64**	4.63	4.61	4.39	4.20	4.02	3.84	3.65	3.44	3.22	3.02	2.77

Daily VOC Emissions (lbs/day)

Equipment	Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9	Month 10	Month 11	Month 12	Month 13	Month 14	Month 15	Month 16	Month 17	Month 18	Month 19	Month 20	Month 21	Month 22	Month 23	Month 24
Pile driving equipment, 255 HP	0.36	0.36	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Roller Compactor, 100 HP	0.29	0.29	0.29	0.29	0.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Backhoe, 150 HP	0.38	0.75	0.75	0.75	0.75	1.13	1.13	1.13	1.13	1.13	1.13	0.75	0.75	0.75	0.75	0.75	0.75	0.38	0.38	0.38	0.38	0.38	0.38	0.38
Forklift, CAT V200, 175 HP	0.16	0.16	0.16	0.16	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.16	0.16	0.16	0.16	0.16	0.00	0.00	0.00	0.00	0.00
Bulldozer, 450G, 400 HP	0.57	0.57	0.57	0.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor Grader, 135 HP	0.21	0.21	0.21	0.21	0.21	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Crane, pile lifting, 25 ton, 160 HP	0.00	0.00	0.00	0.00	0.00	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.22	0.22	0.22	0.22	0.22	0.00	0.00	0.00	0.00
Excavator, 195 HP	0.00	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cranes, 230 ton, 220 HP	0.00	0.00	0.00	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.00	0.00	0.00	0.00	0.00
Cranes, 400 ton, 255 HP	0.00	0.00	0.00	0.00	0.00	0.00	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cranes, 15 ton, 101 HP	0.00	0.00	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00
Manlift, 60ft, 30 HP	0.00	0.00	0.00	0.21	0.42	0.42	0.42	0.63	0.63	0.63	0.63	0.63	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.21	0.21	0.21	0.21	0.00
Scrapers, 550 HP	0.67	0.67	0.67	0.67	0.67	0.00	0.00	0.00	0.00	0.00	0.00	0.67	0.67	0.67	0.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Truck, 225 HP	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
Welding Unit, 70 HP	0.00	0.18	0.18	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.35	0.35	0.35	0.18	0.18	0.00	0.00	0.00	0.00
Dump truck, 210 HP	0.98	0.98	0.98	0.98	0.98	0.49	0.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Boom truck, 220 HP	0.00	0.49	0.49	0.98	0.98	1.48	1.48	1.48	1.48	1.48	1.48	1.48	1.48	1.48	1.48	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Tandem Dump Truck, 30 CY, 250 HP	0.40	0.40	0.40	0.40	0.40	0.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Concrete pump truck, 350 HP	0.00	0.40	0.40	0.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total =	4.52	6.27	6.41	**7.72**	7.13	6.99	6.73	6.45	6.45	6.45	6.15	6.44	6.22	6.22	6.06	4.15	4.15	3.77	3.59	2.61	2.20	2.06	2.06	1.85
Monthly Emissions (lbs/month) =	81	113	115	139	128	126	121	116	116	116	111	116	112	112	109	75	75	68	65	47	40	37	37	33
Annual Emissions (lbs/year) =												1,399	**1,429**	1,429	1,422	1,358	1,304	1,246	1,190	1,121	1,044	965	892	809
Annual Emissions (tons/year) =												0.70	**0.71**	0.71	0.71	0.68	0.65	0.62	0.59	0.56	0.52	0.48	0.45	0.40

Daily SOx Emissions (lbs/day)

Equipment	Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9	Month 10	Month 11	Month 12	Month 13	Month 14	Month 15	Month 16	Month 17	Month 18	Month 19	Month 20	Month 21	Month 22	Month 23	Month 24
Pile driving equipment, 255 HP	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Roller Compactor, 100 HP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Backhoe, 150 HP	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Forklift, CAT V200, 175 HP	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bulldozer, 450G, 400 HP	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor Grader, 135 HP	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Crane, pile lifting, 25 ton, 160 HP	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00
Excavator, 195 HP	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cranes, 230 ton, 220 HP	0.00	0.00	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00
Cranes, 400 ton, 255 HP	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cranes, 15 ton, 101 HP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Manlift, 60ft, 30 HP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Scrapers, 550 HP	0.02	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Truck, 225 HP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Welding Unit, 70 HP	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dump truck, 210 HP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Boom truck, 220 HP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tandem Dump Truck, 30 CY, 250 HP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Concrete pump truck, 350 HP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total =	0.07	0.09	0.09	**0.10**	0.09	0.08	0.08	0.09	0.09	0.09	0.08	0.09	0.09	0.09	0.09	0.05	0.05	0.04	0.04	0.02	0.01	0.01	0.01	0.01
Monthly Emissions (lbs/month) =	1.22	1.57	1.64	1.87	1.62	1.51	1.50	1.54	1.54	1.54	1.40	1.64	1.60	1.60	1.53	0.88	0.88	0.79	0.75	0.34	0.20	0.13	0.13	0.09
Annual Emissions (lbs/year) =												18.58	18.97	**19.00**	18.90	17.91	17.17	16.45	15.69	14.49	13.15	11.74	10.48	8.93
Annual Emissions (tons/year) =												0.01	0.01	**0.01**	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00

Daily PM10 Emissions (lbs/day)

Equipment	Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9	Month 10	Month 11	Month 12	Month 13	Month 14	Month 15	Month 16	Month 17	Month 18	Month 19	Month 20	Month 21	Month 22	Month 23	Month 24
Pile driving equipment, 255 HP	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Roller Compactor, 100 HP	0.15	0.15	0.15	0.15	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Backhoe, 150 HP	0.38	0.75	0.75	0.75	0.75	1.13	1.13	1.13	1.13	1.13	1.13	0.75	0.75	0.75	0.75	0.75	0.75	0.38	0.38	0.38	0.38	0.38	0.38	0.38
Forklift, CAT V200, 175 HP	0.20	0.20	0.20	0.20	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.20	0.20	0.20	0.20	0.20	0.00	0.00	0.00	0.00	0.00
Bulldozer, 450G, 400 HP	0.44	0.44	0.44	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor Grader, 135 HP	0.20	0.20	0.20	0.20	0.20	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Crane, pile lifting, 25 ton, 160 HP	0.00	0.00	0.00	0.00	0.00	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.16	0.16	0.16	0.16	0.16	0.00	0.00	0.00	0.00
Excavator, 195 HP	0.00	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cranes, 230 ton, 220 HP	0.00	0.00	0.00	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.00	0.00	0.00	0.00	0.00
Cranes, 400 ton, 255 HP	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cranes, 15 ton, 101 HP	0.00	0.00	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.00	0.00	0.00
Manlift, 60ft, 30 HP	0.00	0.00	0.00	0.23	0.46	0.46	0.46	0.68	0.68	0.68	0.68	0.68	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.23	0.23	0.23	0.23	0.00
Scrapers, 550 HP	0.37	0.37	0.37	0.37	0.37	0.00	0.00	0.00	0.00	0.00	0.00	0.37	0.37	0.37	0.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Truck, 225 HP	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Welding Unit, 70 HP	0.00	0.09	0.09	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.18	0.18	0.18	0.09	0.09	0.00	0.00	0.00	0.00
Dump truck, 210 HP	0.23	0.23	0.23	0.23	0.23	0.11	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Boom truck, 220 HP	0.00	0.11	0.11	0.23	0.23	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Tandem Dump Truck, 30 CY, 250 HP	0.21	0.21	0.21	0.21	0.21	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Concrete pump truck, 350 HP	0.00	0.21	0.21	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total =	2.42	3.42	3.53	**4.14**	3.92	4.10	3.81	3.92	3.92	3.92	3.71	**3.70**	3.47	3.47	3.27	2.41	2.41	2.03	1.95	1.30	1.05	0.95	0.95	0.72
Monthly Emissions (lbs/month) =	44	62	63	74	71	74	68	71	71	71	67	67	63	63	59	43	43	37	35	23	19	17	17	13
Annual Emissions (lbs/year) =												801	820	**821**	816	785	758	721	687	640	589	535	486	432
Annual Emissions (tons/year) =												0.40	0.41	**0.41**	0.41	0.39	0.38	0.36	0.34	0.32	0.29	0.27	0.24	0.22

Onroad Emission Factors

	Emission Factors (1) NOx	CO	VOC	SOx	PM10	PM2.5
Truck Hauling (lbs/vmt)	0.03821	0.01404	0.00297	0.00003	0.00158	0.00138
Truck Hauling (lbs/1000 gals)	204.23	75.06	15.87	0.18	8.42	7.36584
Light Duty Trucks/Cars (lbs/vmt)(1)	0.00089	0.00928	0.00088	0.00001	0.00009	0.00003
Light Duty Trucks (lbs/1000 gals)(2)	25.02	211.54	19.17	0.20	2.12	1.41229
Medium Duty Trucks (lbs/1000 gals)(3)	135.71	172.26	19.65	0.00	4.57	4.11

Gasoline Equipment Factors - Small Engines

	NOx	CO	(gm/bhp-hr) POC	SO2	PM10
Small Equipment(1) (lbs/bhp-hr)	0.0066	0.082	0.0010	0.00059	0.00072
Small Equipment(1) (lb/1000 gal)	116.78	1459.70	17.75	10.49	12.80

Notes:

(1) NOx, CO and VOC factors reflect Tier 1 Emissions Standards for Large SI Engines, effective starting in 2004.
SO2 and PM10 factors from AP-42 Table 3.3-1.

Title : SJ County 2010 Fleet - PM10
Version : Emfac2007 V2.3 Nov 1 2006
Run Date : 2008/06/13 09:08:41
Scen Year: 2010 -- All model years in the range 1966 to 2010 selected
Season : Annual
Area : San Joaquin County
I/M Stat : Enhanced Interim (2005)
Emissions: Tons Per Day
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	LDA-NCAT	LDA-CAT	LDA-DSL	LDA-TOT	LDT1-NCAT	LDT1-CAT	LDT1-DSL	LDT1-TOT	LDT2-NCA	LDT2-CAT	LDT2-DSL
Vehicles	3383	224182	696	228261	1748	51469	3783	56999	1229	97766	295
VMT/1000	51	8218	17	8286	32	1966	123	2120	23	3799	8
Trips	13394	1407470	3838	1424700	7017	322312	23208	352537	4972	614248	1666
Reactive Organic Gas Emissions											
Run Exh	0.32	0.47	0	0.79	0.21	0.14	0.01	0.36	0.14	0.32	0
Idle Exh	0	0	0	0	0	0	0	0	0	0	0
Start Ex	0.08	0.83	0	0.91	0.04	0.19	0	0.23	0.03	0.44	0
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Total Ex	0.4	1.3	0	1.7	0.25	0.33	0.01	0.59	0.18	0.76	0
Diurnal	0.02	0.21	0	0.23	0.01	0.05	0	0.06	0.01	0.09	0
Hot Soak	0.05	0.28	0	0.33	0.03	0.06	0	0.09	0.02	0.12	0
Running	0.27	0.78	0	1.06	0.09	0.31	0	0.4	0.06	0.62	0
Resting	0.01	0.1	0	0.12	0.01	0.03	0	0.03	0	0.05	0
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Total	0.76	2.67	0	3.43	0.38	0.79	0.01	1.18	0.27	1.64	0
Carbon Monoxide Emissions											
Run Exh	3.91	21.14	0.01	25.05	2.44	6.66	0.07	9.17	1.7	13.57	0.01
Idle Exh	0	0	0	0	0	0	0	0	0	0	0
Start Ex	0.46	9.74	0	10.2	0.24	2.65	0	2.9	0.17	5.53	0
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Total Ex	4.37	30.88	0.01	35.25	2.68	9.31	0.07	12.06	1.87	19.09	0.01
Oxides of Nitrogen Emissions											
Run Exh	0.26	1.97	0.02	2.25	0.16	0.61	0.18	0.95	0.11	1.85	0.01
Idle Exh	0	0	0	0	0	0	0	0	0	0	0
Start Ex	0.02	0.65	0	0.67	0.01	0.15	0	0.16	0.01	0.5	0
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Total Ex	0.28	2.61	0.02	2.92	0.17	0.77	0.18	1.12	0.12	2.35	0.01
Carbon Dioxide Emissions (000)											
Run Exh	0.03	3.17	0.01	3.21	0.02	0.94	0.05	1	0.01	1.82	0
Idle Exh	0	0	0	0	0	0	0	0	0	0	0
Start Ex	0	0.11	0	0.12	0	0.03	0	0.03	0	0.06	0
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Total Ex	0.03	3.28	0.01	3.32	0.02	0.97	0.05	1.04	0.01	1.88	0
PM10 Emissions											
Run Exh	0	0.1	0	0.11	0	0.03	0.01	0.03	0	0.11	0
Idle Exh	0	0	0	0	0	0	0	0	0	0	0
Start Ex	0	0.01	0	0.01	0	0	0	0	0	0.01	0
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Total Ex	0	0.12	0	0.12	0	0.03	0.01	0.04	0	0.12	0
TireWear	0	0.07	0	0.07	0	0.02	0	0.02	0	0.03	0
BrakeWr	0	0.11	0	0.11	0	0.03	0	0.03	0	0.05	0
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Total	0	0.3	0	0.31	0	0.07	0.01	0.09	0	0.2	0
PM2.5 Emissions											
Run Exh	0	0.1	0	0.1	0	0.03	0.01	0.03	0	0.1	0
Idle Exh	0	0	0	0	0	0	0	0	0	0	0
Start Ex	0	0.01	0	0.01	0	0	0	0	0	0.01	0
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Total Ex	0	0.11	0	0.11	0	0.03	0.01	0.03	0	0.11	0
TireWear	0	0.02	0	0.02	0	0	0	0	0	0.01	0
BrakeWr	0	0.05	0	0.05	0	0.01	0	0.01	0	0.02	0
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Total	0	0.17	0	0.18	0	0.04	0.01	0.05	0	0.14	0
Lead	0	0	0	0	0	0	0	0	0	0	0
SOx	0	0.03	0	0.03	0	0.01	0	0.01	0	0.02	0
Fuel Consumption (000 gallons)											
Gasoline	3.85	341.74	0	345.59	2.36	101.27	0	103.63	1.67	196.31	0
Diesel	0	0	0.61	0.61	0	0	4.22	4.22	0	0	0.28

Title : SJ (
Version : E
Run Date : 2
Scen Year: 2
Season : A
Area : Sa
I/M Stat : Er
Emissions: T
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	LDT2-TOT	MDV-NCAT	MDV-CAT	MDV-DSL	MDV-TOT	LHDT1-NC/	LHDT1-CA	LHDT1-DSI	LHDT1-TO	LHDT2-NC/	LHDT2-CA	LHDT2-DSI	LHDT2-TO	MHDT-NCA	MHDT-CAT	MHDT-DSL	MHDT-TOT	HHDT-NCA	HHDT-CAT	HHDT-DSL
Vehicles	99290	549	52855	177	53581	63	7362	2658	10083	23	1366	1730	3119	254	853	4139	5246	17	146	7504
VMT/1000	3830	12	2095	6	2114	1	329	122	452	0	55	68	123	2	39	263	305	0	17	1202
Trips	620886	2374	334290	1099	337763	2088	243426	33433	278947	752	45182	21763	67697	11602	38973	116050	166626	773	6657	37974
Reactive Or																				
Run Exh	0.46	0.1	0.21	0	0.31	0.01	0.13	0.03	0.17	0	0.03	0.02	0.05	0.02	0.03	0.08	0.12	0	0.05	1.52
Idle Exh	0	0	0	0	0	0	0.01	0	0.01	0	0	0	0	0	0	0	0	0	0	0.18
Start Ex	0.47	0.02	0.29	0	0.3	0.02	0.14	0	0.16	0.01	0.03	0	0.04	0.13	0.08	0	0.21	0.02	0.03	0
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Total Ex	0.93	0.12	0.49	0	0.61	0.03	0.29	0.03	0.34	0.01	0.06	0.02	0.09	0.15	0.11	0.08	0.34	0.02	0.08	1.7
Diurnal	0.1	0	0.04	0	0.04	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hot Soak	0.14	0	0.06	0	0.06	0	0.01	0	0.01	0	0	0	0	0.01	0	0	0.01	0	0	0
Running	0.68	0.01	0.27	0	0.28	0.01	0.17	0	0.18	0	0.05	0	0.05	0.06	0.03	0	0.09	0.01	0	0
Resting	0.05	0	0.02	0	0.02	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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Total	1.9	0.13	0.89	0	1.02	0.04	0.48	0.03	0.54	0.01	0.12	0.02	0.15	0.21	0.14	0.08	0.43	0.03	0.08	1.7
Carbon Mor																				
Run Exh	15.27	1.7	7.43	0	9.13	0.23	1.49	0.15	1.87	0.08	0.32	0.1	0.5	0.39	0.51	0.72	1.61	0.16	0.74	6.2
Idle Exh	0	0	0	0	0	0	0.06	0	0.07	0	0.01	0	0.01	0	0.01	0.01	0.03	0	0	0.72
Start Ex	5.7	0.16	3.21	0	3.36	0.09	2.03	0	2.13	0.03	0.45	0	0.48	0.79	1.35	0	2.13	0.25	0.49	0
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Total Ex	20.97	1.86	10.63	0	12.49	0.33	3.58	0.15	4.06	0.11	0.78	0.1	0.99	1.18	1.86	0.73	3.77	0.41	1.23	6.92
Oxides of N																				
Run Exh	1.97	0.1	1.17	0.01	1.28	0	0.2	0.58	0.78	0	0.04	0.4	0.45	0.01	0.12	2.66	2.79	0.01	0.2	21.51
Idle Exh	0	0	0	0	0	0	0	0.01	0.01	0	0	0	0.01	0	0	0.03	0.03	0	0	1.51
Start Ex	0.5	0.01	0.3	0	0.3	0	0.46	0	0.46	0	0.09	0	0.09	0.01	0.13	0	0.14	0	0.06	0
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Total Ex	2.48	0.11	1.46	0.01	1.58	0	0.66	0.58	1.25	0	0.14	0.41	0.55	0.02	0.25	2.7	2.97	0.01	0.26	23.02
Carbon Dio																				
Run Exh	1.84	0.01	1.38	0	1.39	0	0.35	0.07	0.42	0	0.06	0.04	0.1	0	0.03	0.44	0.47	0	0.01	2.43
Idle Exh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.09
Start Ex	0.06	0	0.05	0	0.05	0	0.01	0	0.01	0	0	0	0	0	0	0	0	0	0	0
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Total Ex	1.9	0.01	1.42	0	1.43	0	0.36	0.07	0.44	0	0.06	0.04	0.1	0	0.03	0.44	0.47	0	0.01	2.52
PM10 Emis																				
Run Exh	0.11	0	0.05	0	0.05	0	0	0.01	0.01	0	0	0.01	0.01	0	0	0.09	0.09	0	0	0.85
Idle Exh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.03
Start Ex	0.01	0	0.01	0	0.01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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Total Ex	0.12	0	0.06	0	0.06	0	0.01	0.01	0.01	0	0	0.01	0.01	0	0	0.09	0.09	0	0	0.88
TireWear	0.03	0	0.02	0	0.02	0	0	0	0.01	0	0	0	0	0	0	0	0	0	0	0.05
BrakeWr	0.05	0	0.03	0	0.03	0	0	0	0.01	0	0	0	0	0	0	0	0	0	0	0.04
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Total	0.21	0	0.11	0	0.11	0	0.01	0.01	0.02	0	0	0.01	0.01	0	0	0.1	0.1	0	0	0.96
PM2.5 Emis																				
Run Exh	0.1	0	0.05	0	0.05	0	0	0.01	0.01	0	0	0	0.01	0	0	0.08	0.08	0	0	0.78
Idle Exh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.03
Start Ex	0.01	0	0.01	0	0.01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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Total Ex	0.11	0	0.05	0	0.05	0	0	0.01	0.01	0	0	0	0.01	0	0	0.08	0.08	0	0	0.81
TireWear	0.01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.01
BrakeWr	0.02	0	0.01	0	0.01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.02
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Total	0.14	0	0.07	0	0.07	0	0.01	0.01	0.02	0	0	0.01	0.01	0	0	0.09	0.09	0	0	0.84
Lead	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOx	0.02	0	0.01	0	0.01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.02
Fuel Consu																				
Gasoline	197.98	1.23	147.62	0	148.85	0.27	37.94	0	38.2	0.09	6.41	0	6.5	0.69	3.59	0	4.28	0.11	1.35	0
Diesel	0.28	0	0	0.21	0.21	0	0	6.34	6.34	0	0	3.6	3.6	0	0	39.49	39.49	0	0	226.63

Title : SJ (
Version : E
Run Date : 2
Scen Year: 2
Season : A
Area : Sa
I/M Stat : Er
Emissions: T
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	HHDT-TOT	OBUS-NCA	OBUS-CAT	OBUS-DSL	OBUS-TOT	SBUS-NCA	SBUS-CAT	SBUS-DSL	SBUS-TOT	UB-NCAT	UB-CAT	UB-DSL	UB-TOT	MH-NCAT	MH-CAT	MH-DSL	MH-TOT	MCY-NCAT	MCY-CAT	MCY-DSL	MCY-TOT	ALL-TOT
Vehicles	7667	6	133	80	219	3	40	442	485	4	43	218	265	199	3877	560	4635	12405	5536	0	17941	487792
VMT/1000	1219	0	7	5	12	0	2	22	24	1	6	32	38	2	47	7	56	111	63	0	174	18754
Trips	45405	279	6069	2243	8591	11	160	1770	1941	18	172	871	1061	20	388	56	464	24807	11071	0	35878	3342490
Reactive Or																						
Run Exh	1.58	0	0.01	0	0.01	0	0	0.01	0.02	0.01	0.02	0.03	0.06	0.01	0.02	0	0.03	0.43	0.12	0	0.54	4.5
Idle Exh	0.18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.2
Start Ex	0.05	0	0.01	0	0.01	0	0	0	0	0	0	0	0	0	0	0	0	0.07	0.03	0	0.1	2.49
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Total Ex	1.8	0	0.02	0	0.02	0	0.01	0.01	0.02	0.01	0.02	0.03	0.06	0.01	0.02	0	0.04	0.5	0.14	0	0.64	7.19
Diurnal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.01	0.03	0	0.04	0.48
Hot Soak	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.01	0.01	0	0.02	0.66
Running	0.01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.04	0.04	0	0.09	2.85
Resting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.01	0	0.02	0.24
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Total	1.81	0.01	0.02	0	0.03	0	0.01	0.01	0.02	0.01	0.02	0.03	0.06	0.01	0.02	0	0.04	0.56	0.24	0	0.8	11.42
Carbon Mor																						
Run Exh	7.1	0.01	0.09	0.01	0.12	0.03	0.06	0.09	0.17	0.13	0.25	0.1	0.48	0.32	0.62	0.01	0.95	5.21	0.9	0	6.1	77.52
Idle Exh	0.72	0	0	0	0	0	0	0.01	0.01	0	0	0	0	0	0	0	0	0	0	0	0	0.84
Start Ex	0.74	0.02	0.19	0	0.21	0	0.01	0	0.01	0	0.03	0	0.03	0	0.01	0	0.01	0.22	0.18	0	0.4	28.31
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Total Ex	8.56	0.03	0.29	0.01	0.33	0.03	0.07	0.09	0.19	0.14	0.28	0.1	0.51	0.32	0.63	0.01	0.96	5.43	1.08	0	6.51	106.67
Oxides of N																						
Run Exh	21.72	0	0.03	0.04	0.07	0	0.01	0.29	0.3	0	0.07	0.65	0.72	0.01	0.09	0.07	0.17	0.16	0.08	0	0.24	33.7
Idle Exh	1.51	0	0	0	0	0	0	0.02	0.02	0	0	0	0	0	0	0	0	0	0	0	0	1.58
Start Ex	0.06	0	0.02	0	0.02	0	0	0	0	0	0	0	0	0	0	0	0	0.01	0	0	0.01	2.44
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Total Ex	23.29	0	0.05	0.04	0.1	0	0.01	0.31	0.32	0	0.08	0.65	0.73	0.01	0.09	0.07	0.17	0.17	0.08	0	0.25	37.71
Carbon Dio																						
Run Exh	2.44	0	0.01	0.01	0.01	0	0	0.04	0.04	0	0.01	0.09	0.09	0	0.04	0.01	0.05	0.01	0.01	0	0.02	11.08
Idle Exh	0.09	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.1
Start Ex	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.28
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Total Ex	2.53	0	0.01	0.01	0.01	0	0	0.04	0.04	0	0.01	0.09	0.09	0	0.04	0.01	0.05	0.02	0.01	0	0.03	11.46
PM10 Emis																						
Run Exh	0.85	0	0	0	0	0	0	0.01	0.01	0	0	0.01	0.01	0	0	0	0	0.01	0	0	0.01	1.3
Idle Exh	0.03	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.03
Start Ex	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.03
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Total Ex	0.88	0	0	0	0	0	0	0.01	0.01	0	0	0.01	0.01	0	0	0	0	0.01	0	0	0.01	1.36
TireWear	0.05	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.21
BrakeWr	0.04	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.28
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Total	0.96	0	0	0	0	0	0	0.01	0.01	0	0	0.01	0.01	0	0	0	0	0.01	0	0	0.01	1.84
PM2.5 Emis																						
Run Exh	0.78	0	0	0	0	0	0	0.01	0.01	0	0	0.01	0.01	0	0	0	0	0	0	0	0	1.19
Idle Exh	0.03	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.03
Start Ex	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.03
	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
Total Ex	0.81	0	0	0	0	0	0	0.01	0.01	0	0	0.01	0.01	0	0	0	0	0	0	0	0	1.25
TireWear	0.01	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.05
BrakeWr	0.02	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.12
	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
Total	0.84	0	0	0	0	0	0	0.01	0.01	0	0	0.01	0.01	0	0	0	0	0.01	0	0	0.01	1.42
Lead	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SOx	0.02	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.11
Fuel Consu																						
Gasoline	1.45	0.02	0.62	0	0.63	0.02	0.19	0	0.21	0.08	0.58	0	0.66	0.21	3.78	0	3.98	2.61	1.37	0	3.99	855.95
Diesel	226.63	0	0	0.78	0.78	0	0	3.31	3.31	0	0	8.03	8.03	0	0	1.06	1.06	0	0	0	0	294.57

Daily Dust Emissions (lbs/day) - PM2.5

Equipment	Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9	Month 10	Month 11	Month 12	Month 13	Month 14	Month 15	Month 16	Month 17	Month 18	Month 19	Month 20	Month 21	Month 22	Month 23	Month 24
Pile driving equipment, 255 HP																								
Roller Compactor, 100 HP	0.08	0.08	0.08	0.08	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Backhoe, 150 HP	6.68E-02	1.34E-01	1.34E-01	1.34E-01	1.34E-01	2.01E-01	2.01E-01	2.01E-01	2.01E-01	2.01E-01	2.01E-01	1.34E-01	1.34E-01	1.34E-01	1.34E-01	1.34E-01	1.34E-01	6.68E-02	6.68E-02	6.68E-02	6.68E-02	6.68E-02	6.68E-02	6.68E-02
Forklift, CAT V200, 175 HP																								
Bulldozer, 450G, 400 HP	1.85	1.85	1.85	1.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor Grader, 135 HP	0.06	0.06	0.06	0.06	0.06	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Crane, pile lifting, 25 ton, 160 HP																								
Excavator, 195 HP	0.00E+00	2.25E-02	2.25E-02	2.25E-02	2.25E-02	2.25E-02	2.25E-02	2.25E-02	2.25E-02	2.25E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cranes, 230 ton, 220 HP																								
Cranes, 400 ton, 255 HP																								
Cranes, 15 ton, 101 HP																								
Manlift, 60ft, 30 HP																								
Scrapers, 550 HP	1.85	1.85	1.85	1.85	1.85	0.00	0.00	0.00	0.00	0.00	0.00	1.85	1.85	1.85	1.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Truck, 225 HP	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Welding Unit, 70 HP																								
Dump truck, 210 HP	0.15	0.15	0.15	0.15	0.15	0.08	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Boom truck, 220 HP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tandem Dump Truck, 30 CY, 250 HP	0.08	0.08	0.08	0.08	0.08	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Concrete pump truck, 350 HP	0.00	0.08	0.08	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Windblown Dust (active construction area)	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Worker Unpaved Road Travel	0.01	0.01	0.02	0.02	0.03	0.04	0.05	0.06	0.06	0.07	0.09	0.10	0.11	0.11	0.11	0.11	0.10	0.09	0.08	0.07	0.06	0.04	0.03	0.02
Delivery Truck Unpaved Road Travel	0.03	0.12	0.20	0.29	0.25	0.29	0.37	0.43	0.29	0.24	0.19	0.18	0.15	0.12	0.11	0.09	0.04	0.03	0.06	0.06	0.15	0.08	0.06	0.06
Total =	4.50	4.76	**4.84**	4.94	2.98	1.09	1.05	1.04	0.90	0.86	0.81	2.59	2.56	2.54	2.52	0.66	0.60	0.51	0.54	0.53	0.60	0.51	0.49	0.47
Monthly Emissions (lbs/month) =	80.97	85.71	87.15	88.97	53.68	19.60	18.92	18.78	16.25	15.51	14.59	46.62	46.14	45.68	45.44	11.93	10.84	9.22	9.75	9.58	10.87	9.18	8.80	8.54
Annual Emissions (lbs/year) =												**546.75**	511.91	471.88	430.17	353.13	310.29	299.91	290.74	281.54	276.16	269.84	264.05	225.97
Annual Emissions (tons/year) =												**0.27**	0.26	0.24	0.22	0.18	0.16	0.15	0.15	0.14	0.14	0.13	0.13	0.11

Daily Dust Emissions (lbs/day) - PM10

Equipment	Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9	Month 10	Month 11	Month 12	Month 13	Month 14	Month 15	Month 16	Month 17	Month 18	Month 19	Month 20	Month 21	Month 22	Month 23	Month 24
Pile driving equipment, 255 HP																								
Roller Compactor, 100 HP	0.84	0.84	0.84	0.84	0.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Backhoe, 150 HP	1.90	3.80	3.80	3.80	3.80	5.70	5.70	5.70	5.70	5.70	5.70	3.80	3.80	3.80	3.80	3.80	3.80	1.90	1.90	1.90	1.90	1.90	1.90	1.90
Forklift, CAT V200, 175 HP																								
Bulldozer, 450G, 400 HP	3.36	3.36	3.36	3.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor Grader, 135 HP	0.83	0.83	0.83	0.83	0.83	0.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Crane, pile lifting, 25 ton, 160 HP																								
Excavator, 195 HP	0.00	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cranes, 230 ton, 220 HP																								
Cranes, 400 ton, 255 HP																								
Cranes, 15 ton, 101 HP																								
Manlift, 60ft, 30 HP																								
Scrapers, 550 HP	3.36	3.36	3.36	3.36	3.36	0.00	0.00	0.00	0.00	0.00	0.00	3.36	3.36	3.36	3.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Truck, 225 HP	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19	2.19
Welding Unit, 70 HP																								
Dump truck, 210 HP	1.53	1.53	1.53	1.53	1.53	0.77	0.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Boom truck, 220 HP																								
Tandem Dump Truck, 30 CY, 250 HP	0.77	0.77	0.77	0.77	0.77	0.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Concrete pump truck, 350 HP	0.00	0.77	0.77	0.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Windblown Dust (active construction area)	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
Worker Unpaved Road Travel	0.07	0.11	0.17	0.20	0.28	0.36	0.51	0.61	0.62	0.65	0.90	0.99	1.07	1.11	1.07	1.12	1.01	0.87	0.83	0.73	0.57	0.36	0.30	0.15
Delivery Truck Unpaved Road Travel	0.29	1.22	1.96	2.94	2.50	2.89	3.72	4.31	2.89	2.45	1.91	1.81	1.47	1.18	1.08	0.88	0.39	0.29	0.64	0.64	1.52	0.78	0.64	0.64
Total =	15.41	19.20	20.00	**21.01**	16.52	13.94	13.31	13.24	11.83	11.41	10.98	12.43	12.16	11.90	11.77	8.27	7.67	5.53	5.83	5.73	6.45	5.51	5.30	5.15
Monthly Emissions (lbs/month) =	277.40	345.58	359.94	378.12	297.38	250.87	239.58	238.23	212.86	205.46	197.63	223.66	218.83	214.27	211.91	148.85	138.02	99.58	104.95	103.21	116.14	99.24	95.45	92.78
Annual Emissions (lbs/year) =												**3226.71**	3168.13	3036.83	2888.79	2659.52	2500.16	2348.87	2214.25	2079.22	1982.51	1876.28	1774.11	1643.22
Annual Emissions (tons/year) =												**1.61**	1.58	1.52	1.44	1.33	1.25	1.17	1.11	1.04	0.99	0.94	0.89	0.82

Construction Equipment Process Rates For Dust Calculations

Equipment	Daily Process Rate/Unit	Units	Total Daily Process Rate Month 1	Month 2	Month 3	Month 4	Month 5	Month 6	Month 7	Month 8	Month 9	Month 10	Month 11	Month 12	Month 13	Month 14	Month 15	Month 16	Month 17	Month 18	Month 19	Month 20	Month 21	Month 22	Month 23	Month 24
Pile driving equipment, 255 HP	N/A	N/A																								
Roller Compactor, 100 HP	3.0	vmt/day	3.03	3.03	3.03	3.03	3.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Backhoe, 150 HP	1260	tons/day	1260.00	2520.00	2520.00	2520.00	2520.00	3780.00	3780.00	3780.00	3780.00	3780.00	3780.00	2520.00	2520.00	2520.00	2520.00	2520.00	2520.00	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00
Forklift, CAT V200, 175 HP	N/A	N/A																								
Bulldozer, 450G, 400 HP	8	hrs/day	8.00	8.00	8.00	8.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor Grader, 135 HP	3.0	vmt/day	3.03	3.03	3.03	3.03	3.03	3.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Crane, pile lifting, 25 ton, 160 HP	N/A	N/A																								
Excavator, 195 HP	1260.0	tons/day	0.00	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00	1260.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cranes, 230 ton, 220 HP	N/A	N/A																								
Cranes, 400 ton, 255 HP	N/A	N/A																								
Cranes, 15 ton, 101 HP	N/A	N/A																								
Manlift, 60ft, 30 HP	N/A	N/A																								
Scrapers, 550 HP	8	hrs/day	8.00	8.00	8.00	8.00	8.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	8.00	8.00	8.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water Truck, 225 HP	9.1	vmt/day	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09	9.09
Welding Unit, 70 HP	N/A	N/A																								
Dump truck, 210 HP	3.0	vmt/day	6.06	6.06	6.06	6.06	6.06	3.03	3.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Boom truck, 220 HP	N/A	N/A																								
Tandem Dump Truck, 30 CY, 250 HP	3.0	vmt/day	3.03	3.03	3.03	3.03	3.03	3.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Concrete pump truck, 350 HP	3.0	vmt/day	0.00	3.03	3.03	3.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Windblown Dust (active construction area)	191,400	scf/day	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400	191,400
Workers	0.1	vmt/day	1.08	1.70	2.67	3.13	4.32	5.57	7.73	9.32	9.49	9.94	13.81	15.17	16.31	16.93	16.42	17.16	15.45	13.35	12.67	11.19	8.69	5.57	4.60	2.33
Delivery Trucks	0.25	vmt/day	1.50	6.25	10.00	15.00	12.75	14.75	19.00	22.00	14.75	12.50	9.75	9.25	7.50	6.00	5.50	4.50	2.00	1.50	3.25	3.25	7.75	4.00	3.25	3.25

Longest dimension of construction site 1000 feet

Notes - Fugitive Dust Emission Calculations

(1) Wind erosion emission factor for active construction area is based on "Improvement of Specific Emission Factors (BACM Project No. 1), Final Report", prepared for South Coast AQMD by Midwest Research Institute, March 1996.
(2) Material unloading emission factors are based on AP-42, Section 13.2.4, 11/06.
(Based on average annual wind speed recorded onsite and default soil moisture contents.)
(3) Trenching emission factor is based on AP-42, Table 11.9-2 (dragline operations), 1/95.
(Based on default soil moisture content.)
(4) Unpaved surface travel emission factors for water trucks, loaders, dump trucks, forklifts, delivery trucks, are based on AP-42, Section 13.2.2, 11/06.
(Based on default soil silt content.)
(5) Dust control efficiency for unpaved road travel and active excavation area is based on "Control of Open Fugitive Dust Sources", U.S. EPA, 9/88.
(Based on default evaporation rate shown in EPA document, Figure 3-2, 9/88, and typical water application rate shown in EPA document, page 3-23, 9/88.)

Fugitive Dust Controlled Emission Factors

Equipment	Units	Uncontrolled PM2.5 Emission Factor(1) (lbs/unit)	Uncontrolled PM10 Emission Factor(1) (lbs/unit)	Control Factor(1) (%)	Controlled PM2.5 Emission Factor(1) (lbs/unit)	Controlled PM10 Emission Factor(1) (lbs/unit)
Pile driving equipment, 255 HP	N/A					
Roller Compactor, 100 HP	vmt	0.33	3.25	92%	0.03	0.28
Backhoe, 150 HP	tons	5.30E-05	1.51E-03	0%	0.00	0.00
Forklift, CAT V200, 175 HP	N/A					
Bulldozer, 450G, 400 HP	hours	0.23	0.42	0%	0.23	0.42
Motor Grader, 135 HP	vmt	0.02	0.28	0%	0.02	0.28
Crane, pile lifting, 25 ton, 160 HP	N/A					
Excavator, 195 HP	tons	1.79E-05	1.18E-04	0%	1.79E-05	1.18E-04
Cranes, 230 ton, 220 HP	N/A					
Cranes, 400 ton, 255 HP	N/A					
Cranes, 15 ton, 101 HP	N/A					
Manlift, 60ft, 30 HP	N/A					
Scrapers, 550 HP	hours	0.23	0.42	0%	0.23	0.42
Water Truck, 225 HP	vmt	0.28	2.84	92%	0.02	0.24
Welding Unit, 70 HP	N/A					
Dump truck, 210 HP	vmt	0.30	2.98	92%	0.03	0.25
Boom truck, 220 HP	N/A					
Tandem Dump Truck, 30 CY, 250 HP	vmt	0.30	2.98	92%	0.03	0.25
Concrete pump truck, 350 HP	vmt	0.30	2.98	92%	0.03	0.25
Windblown Dust (active construction area)	sq.ft.	6.73E-06	1.682E-05	92%	5.71E-07	1.43E-06
Worker Unpaved Road Travel	vmt	0.08	0.77	92%	0.01	0.07
Delivery Truck Unpaved Road Travel	vmt	0.23	2.31	92%	0.02	0.20

APPENDIX 5.1F

Revised July 2009

Offsets and Interpollutant Offset Ratio Analysis

APPENDIX 5.1F (REVISED JULY 2009)

Offsets and Interpollutant Offset Ratio Analysis

Under District Rule 2201, LEC must provide offsets for the portion of the facility emissions after modification that exceed the SJVAPCD offset thresholds. Because the proposed project is a modification to an existing stationary source, the calculation of the offset requirements must account for the emissions from the existing NCPA Lodi facility. Table 5.1F-1R shows annual proposed potential to emit from the new LEC units, the annual potential to emit for the existing units, and the total emissions from the combined facility after modification, and compares these totals with the offset thresholds to determine the offsets required for the project.

TABLE 5.1F-1R
Offset Requirements for the LEC

	Annual Emissions, tons			
	NOx	**SOx**	**VOC**	**PM_{10}**
LEC Project Emissions	~~71.5~~ 76.3	~~24.3~~ 26.9	~~17.5~~ 16.8	~~44.0~~ 44.1
Pre-Existing PTE	20.4	5.7	25.9	8.8
Rule 2201 Offset Threshold	10.0	27.4	10.0	14.6
Emissions Required to be Offset	~~71.5~~ 76.3	~~2.7~~ 5.3	~~17.5~~ 16.8	38.2

District Rule 2201 allows the APCO to approve interpollutant offsets on a case-by-case basis. LEC proposes to use the excess SO_2 ERCs as offsets for PM_{10}. The ~~interpolllutant offset ratio analysis in Attachment 5.1F-1 demonstrates~~ SJVAPCD has determined that ratio of 1~~.11~~ tons of SO_2 for 1 ton of PM_{10} will provide equivalent air quality benefits as required under the NSR rules. Additional information regarding the District's interpollutant offset ratio is provided in Attachment 5.1F-1R.

The required quarterly calculation of offsets is provided in Table 5.1F-2R. This calculation demonstrates that more than sufficient offsets are being provided to achieve the no net increase provision of the District NSR rule (Rule 2201 §1.0).

Table 5.1F-3R provides a demonstration that sufficient mitigation is being provided under CEQA. Table 5.1F-4R[11] provides documentation regarding the location and method of reduction for each ERC certificate proposed to be used for the project.

[11] Table 5.1F-4R has been updated to reflect the new certificate numbers assigned to the ERCs by the District upon transfer of ownership of the certificates to NCPA.

Table 5.1F-2R
NCPA Lodi Energy Center
Quarterly Offset Summary (lbs/qtr)
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

VOC (pounds)					
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Annual (tpy)
Project VOC Emissions	**8,243**	**8,334**	**8,575**	**8,480**	**33,633**
Pre-Existing PTE	12,780	12,922	13,064	13,064	51,830
VOC Offset Threshold (1)	5,000	5,000	5,000	5,000	20,000
VOC Emissions Required to be Offset (2)	8,243	8,334	8,575	8,480	33,633
VOC ERCs Required for District regulations (3)	**12,365**	**12,501**	**12,863**	**12,721**	**50,450**
VOC ERCs-- Cert No. S-2860-1	12,600	12,600	12,600	12,600	50,400
VOC ERCs Excess (Shortfall)	**235**	**99**	**(263)**	**(121)**	**-50**
Use NOx ERCs to make up 3rd and 4th Q shortfall (4)	0	0	263	121	384
VOC ERCs Excess (Shortfall)	**235**	**99**	**0**	**0**	**334**
NOx					
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Annual (tpy)
Project NOx Emissions	**38,341**	**38,713**	**37,427**	**38,141**	**152,622**
Pre-Existing PTE	10,080	10,192	10,304	10,304	40,880
NOx Offset Threshold (1)	5,000	5,000	5,000	5,000	20,000
NOx Emissions Required to be Offset (2)	38,341	38,713	37,427	38,141	152,622
NOx ERCs Required for District regulations (3)	**57,511**	**58,070**	**56,140**	**57,212**	**228,933**
NOx ERCs					
S-2857-2	0	0	0	1,031	1,031
S-2848-2	1,457	0	1,145	2,959	5,561
S-2849-2	2,682	3,241	938	687	7,548
S-2850-2	23,349	23,151	24,224	24,469	95,193
S-2851-2	1,019	2,105	1,303	264	4,691
S-2852-2	2,296	7,000	9,353	954	19,603
S-2854-2	0	1,437	0	0	1,437
S-2855-2	400	79	4,227	12,090	16,796
C-915-2	129	137	122	177	565
C-916-2	8,966	1,122	303	0	10,391
C-914-2	4,702	6,728	3,983	1,831	17,244
N-755-2	0	0	27,616	0	27,616
N-754-2	321	274	790	147	1,532
S-2894-2	9,367	22,816	6,006	26,405	64,594
S-2895-2	0	0	0	3,406	3,406
Total	54,688	68,090	80,010	74,420	277,208
NOx ERCs Excess (Shortfall)	**(2,823)**	**10,020**	**23,870**	**17,208**	**48,275**
Use ERCs from 3rd Q to make up 1st Q shortfall (5)	2,823	0	-2,823	0	0
NOx ERCs Excess (Shortfall)	**0**	**10,020**	**21,047**	**17,208**	**48,275**
Use NOx ERCs to make up 3rd and 4th Q VOC shortfall (4)	0	0	-263	-121	-384
NOx ERCs Excess (Shortfall)	**0**	**10,020**	**20,784**	**17,088**	**47,891**

Table 5.1F-2R (cont'd)

SOx					
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Annual (tpy)
Project SOx Emissions	**13,279**	**13,425**	**13,572**	**13,572**	**53,848**
Pre-Existing PTE	2,893	2,893	2,893	2,893	11,571
SOx Offset Threshold [(1)]	13,688	13,688	13,688	13,688	54,750
Emissions Offset Quantity (EOQ) percentage	25%	25%	25%	25%	
SOx Emissions Required to be Offset [(2)]	2,667	2,667	2,667	2,667	10,669
SOx ERCs Required for District Regulations [(3)]	**4,001**	**4,001**	**4,001**	**4,001**	**16,003**
SOx ERCs					
S-2843-5	13,298	10,631	12,619	13,452	50,000
S-2845-5	7,998	9,131	7,319	8,152	32,600
S-2858-5	9,100	9,100	9,080	9,100	36,380
N-759-5	0	0	12,651	0	12,651
N-758-5	0	0	11,045	0	11,045
S-2846-5	931	931	931	931	3,724
N-757-5	0	0	3,600	0	3,600
Total	31,327	29,793	57,245	31,635	150,000
SOx ERCs Used for PM10	**22,684**	**22,712**	**23,574**	**14,500**	**83,471**
Total SOx ERCs Used (SOx and PM10)	**26,685**	**26,713**	**27,575**	**18,501**	**99,474**
SOx ERCs Excess (Shortfall)	**4,642**	**3,080**	**29,670**	**13,134**	**50,526**
PM10					
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Annual (tpy)
Project PM10 Emissions	**21,731**	**21,970**	**22,208**	**22,208**	**88,117**
Pre-Existing PTE	4,321	4,369	4,417	4,417	17,524
PM10 Offset Threshold [(1)]	7,300	7,300	7,300	7,300	29,200
Emissions Offset Quantity (EOQ) percentage	25%	25%	25%	25%	
PM10 Emissions Required to be Offset [(2)]	19,110	19,110	19,110	19,110	76,441
PM10 ERCs Required for District regulations [(3)]	**28,665**	**28,665**	**28,665**	**28,665**	**114,661**
PM10 ERCs					
S-2844-4	5,830	5,830	4,500	9,830	25,990
C-911-4	0	0	0	4,244	4,244
N-756-4	81	78	583	58	800
C-913-4	10	45	0	28	83
C-912-4	60	0	8	5	73
Total	5,981	5,953	5,091	14,165	31,190
PM10 ERCs Excess (Shortfall)	**(22,684)**	**(22,712)**	**(23,574)**	**(14,500)**	**-83,471**
PM10 Reductions from SOx ERCs (at 1.0 to 1.0) [(6)]	**22,684**	**22,712**	**23,574**	**14,500**	**83,471**
PM10 Reductions Excess (Shortfall)	**0**	**0**	**0**	**0**	**0**

Notes:

1. Offset thresholds from SJVAPCD Rule 2201, Table 4.1
2. Offset liability from SJVAPCD Rule 2201, Section 4.7.2
3. Max distance ratio assumed based on SJVAPCD Rule 2201, Table 4.2: 1.5
4. SJVAPCD Rule 2201. Use NOx/VOC ratio of 1.00 per District.
5. SJVAPCD Rule 2201, Section 4.13.8.

Table 5.1F-3R
NCPA Lodi Energy Center
CEQA Mitigation Summary
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

VOC	tons per year
Project VOC Emissions	16.8
VOC ERCs Required for CEQA Mitigation	**16.8**
VOC ERCs-- Cert No. S-2860-1	25.2
VOC ERCs Excess (Shortfall)	**8.4**

NOx	tons per year
Project NOx Emissions	76.3
NOx ERCs Required for CEQA Mitigation	**76.3**
NOx ERCs	
S-2857-2	0.5
S-2848-2	2.8
S-2849-2	3.8
S-2850-2	47.6
S-2851-2	2.3
S-2852-2	9.8
S-2854-2	0.7
S-2855-2	8.4
C-915-2	0.3
C-916-2	5.2
C-914-2	8.6
N-755-2	13.8
N-754-2	0.8
S-2894-2	32.3
S-2895-2	1.7
Total	138.6
NOx ERCs Excess (Shortfall)	**62.3**

SOx	tons per year
Project SOx Emissions	26.9
SOx ERCs Required for CEQA Mitigation	**26.9**
SOx ERCs	
S-2843-5	25.0
S-2845-5	16.3
S-2858-5	18.2
N-759-5	6.3
N-758-5	5.5
S-2846-5	1.9
N-757-5	1.8
Total	75.0
SOx ERCs Excess (Shortfall)	**48.1**
SOx ERCs Used for PM10	**0.0**
SOx ERCs Excess (Shortfall)	**48.1**

Table 5.1F-3R (cont'd)

PM10	tons per year
Project PM10 Emissions	44.1
PM10 ERCs Required for CEQA Mitigation	**44.1**
PM10 ERCs	
S-2844-4	13.0
C-911-4	2.1
N-756-4	0.4
C-913-4	0.0
C-912-4	0.0
Total	15.6
PM10 ERCs Excess (Shortfall)	**(28.5)**
PM10 Reductions from SOx ERCs (at 1.11 to 1.0) (1)	**28.5**
PM10 Reductions Excess (Shortfall)	**0.0**

Notes:

1. SOx:PM10 ratio evaluation from District analysis. Use 1.00

Table 5.1F-4R
Northern California Power Agency (NCPA) ERCs
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

Original ERC Certificate No.	NCPA Certificate No.	Date of Reduction	Issue date	ERCs Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual	Prevous Owner	Location of Reduction	Method of Reduction
SOx											
S-2470-5	S-2843-5	5/18/1993	3/23/2007	13,298	10,631	12,619	13,452	50,000	Gulf Capital Partners, Inc.	400 South M Street, Tulare, CA	boiler retrofit
S-2486-5	S-2845-5	5/18/1993	4/10/2007	7,998	9,131	7,319	8,152	32,600	Gulf Capital Partners, Inc.	400 South M Street, Tulare, CA	boiler retrofit
S-2745-5	S-2858-5	9/10/1979	12/26/2007	9,100	9,100	9,080	9,100	36,380	Gulf Capital Partners, Inc.	20807 Stockdale Highway, Bakersfield, CA	shutdown of entire stationary source
N-641-5	N-759-5	7/1/1991	5/7/2007	0	0	12,651	0	12,651	Gulf Capital Partners, Inc.	4000 Yosemite Blvd, Modesto	reduce fuel oil consumption
N-631-5	N-758-5	1/1/1992	4/23/2007	0	0	11,045	0	11,045	Gulf Capital Partners, Inc.	1785 N Ashby Rd, Merced	fuel limit on boilers
S-2503-5 (partial)	S-2846-5	11/30/1983	4/30/2007	~~2,440~~ 931	~~2,467~~ 931	~~2,494~~ 931	~~2,494~~ 931	~~9,895~~ 3,724	Gulf Capital Partners, Inc.	6500 Refinery Ave, Bakersfield	shutdown of refinery equipment
N-624-5	N-757-5	1/1/1992	5/2/2007	0	0	3,600	0	3,600	Gulf Capital Partners, Inc.	1785 N Ashby Rd, Merced	fuel limit on boilers
PM10											
S-2479-4	S-2844-4	6/30/1995	3/28/2007	5,830	5,830	4,500	9,830	25,990	Gulf Capital Partners, Inc.	400 South M Street, Tulare, CA	shutdown of feedmill
C-769-4	C-911-4	7/3/1997	12/13/2006	0	0	0	4,244	4,244	Gulf Capital Partners, Inc.	10833 S Cornelia Ave, Raisin City, CA	shutdown of cotton ginning operations
N-595-4	N-756-4	1/3/2002	2/6/2007	81	78	583	58	800	Gulf Capital Partners, Inc.	3200 E Eight Mile Rd, Stockton, CA 95212	shutdown of boilers
C-804-4	C-913-4	7/27/1994	3/29/2007	10	45	0	28	83	Gulf Capital Partners, Inc.	32180 Auberry Road	shutdown of boilers
C-801-4	C-912-4	11/9/1994	3/29/2007	60	0	8	5	73	Gulf Capital Partners, Inc.	57839 Road 225	shutdown of oil-fired boilers
NOx											
S-2706-2	S-2857-2	9/15/2003	12/5/2007	0	0	0	1031	1031	Gulf Capital Partners, Inc.	Bear Mtn Blvd & Gosford Rd, Bakersfield, CA	shutdown of IC engines
S-2517-2	S-2848-2	2/24/1992	4/26/2007	1457	0	1145	2959	5561	Gulf Capital Partners, Inc.	Heavy Oil Western Stationary Source 27/28S/21E	convert steam generators to gas firing
S-2519-2	S-2849-2	5/20/1992	4/26/2007	2682	3241	938	687	7548	Gulf Capital Partners, Inc.	Heavy Oil Western - S. Belridge, Midway Sunset NE07/32S/23E	convert steam generators to gas firing
S-2520-2	S-2850-2	5/20/1992	4/26/2007	23349	23151	24224	24469	95193	Gulf Capital Partners, Inc.	Heavy Oil Western - S. Belridge, Midway Sunset NE35/32S/23E	convert steam generators to gas firing
S-2521-2	S-2851-2	5/20/1992	4/26/2007	1,019	2,105	1,303	264	4,691	Gulf Capital Partners, Inc.	Heavy Oil Western - S. Belridge, Midway Sunset SE16/31S/22E	convert steam generators to gas firing
S-2522-2	S-2952-2	5/20/1992	4/26/2007	2,296	7,000	9,353	954	19,603	Gulf Capital Partners, Inc.	Heavy Oil Western - S. Belridge, Midway Sunset SE21/31S/22E	convert steam generators to gas firing
S-2523-2	S-2854-2	2/24/1992	4/26/2007	0	1,437	0	0	1,437	Gulf Capital Partners, Inc.	Heavy Oil Western - S. Belridge, Midway Sunset 28/28S/21E	convert steam generators to gas firing
S-2688-2	S-2855-2	2/24/1992	11/14/2007	400	79	4,227	12,090	16,796	Gulf Capital Partners, Inc.	Heavy Oil Western Stationary Source 33/28S/21E	convert steam generators to gas firing
C-894-2	C-915-2	10/8/2002	2/25/2008	129	137	122	117	505	Gulf Capital Partners, Inc.	10701 Idaho Ave, Hanford, CA 93230	shutdown of boilers
C-895-2	C-916-2	11/5/1992	2/25/2008	8,966	1,122	303	0	10,391	Gulf Capital Partners, Inc.	10701 Idaho Ave, Hanford, CA 93230	modification of boiler
C-808-2	C-914-2	10/2/1992	4/26/2007	4,702	6,728	3,983	1,831	17,244	Gulf Capital Partners, Inc.	2365 E North Ave, Fresno, CA 93725	shutdown of entire stationary source
N-58-2	N-755-2	7/1/1991	9/2/1994	0	0	27,616	0	27,616	Del Monte Foods, USA	4000 Yosemite Blvd, Modesto	reduce use of #6 fuel oil in boiler
N-316-2	N-754-2	5/31/2001	3/14/2003	321	274	790	147	1,532	Del Monte Corporation	202 N Filbert, Stockton, CA 95205	shutdown of boilers
S-2363-2	S-2894-2	12/5/1990	9/25/2006	9,367	22,816	6,006	26,405	64,594	Bullard Energy Center, LLC	Elk Hills, Tupman, CA STR NE35/30S/23E	engine retrofit
S-2767-2	S-2895-2	4/19/1991	1/28/2008	0	0	0	3,406	3,406	Bullard Energy Center, LLC	Heavy Oil Western, Belridge Field STR 02/29S/21E	steam generator retrofit
S-2769-2	not purchased	~~5/20/1992~~	~~1/28/2008~~	~~5,123~~	~~5,415~~	~~2,148~~	~~3,593~~	~~16,279~~	~~Bullard Energy Center, LLC~~	~~Heavy Oil Western, S Belridge, Midway Sunset STR34/28S/21E~~	~~convert steam generators to gas firing~~
S-2770-2	not purchased	~~2/24/1992~~	~~1/28/2008~~	~~0~~	~~9,294~~	~~4,654~~	~~14,613~~	~~28,561~~	~~Bullard Energy Center, LLC~~	~~Heavy Oil Western Stationary Source STR 34/28S/21E~~	~~convert steam generators to gas firing~~
VOC											
S-2748-1 (partial)	S-2860-1	9/10/1979	12/26/2007	~~22,968~~ 12,600	~~25,523~~ 12,600	~~28,078~~ 12,600	~~28,078~~ 12,600	~~104,647~~ 50,400	Frito-Lay North America Inc	20807 Stockdale Highway Bakersfield, CA NE06/30S/26E	shutdown of entire stationary source

Attachment 5.1F-1R
Interpollutant Offset Analysis

ATTACHMENT 5.1F-1 (REVISED JULY 2009)

Interpollutant Offset Analysis

The objective of an emission offset requirement is to ensure that new projects will have a net air quality benefit in the region. The offset program seeks to achieve this by reducing emissions at one location to balance, or offset, an emission increase elsewhere.

The simplest case involves the generation of emission offsets by reductions from an existing source at, or near, the new source. When the pollutants are the same and the location is the same, the presence or absence of a net air quality benefit is relatively easy to determine: if the new emissions are less than the old emissions, a regional net air quality benefit is achieved.

When the location of the source of offsets is different from the source of new emissions, the areas impacted by the two sources differ. It is often impossible to demonstrate that the area impacted by the new source is benefited everywhere by the reductions from the existing source. Agencies usually address this by setting an offset ratio that takes distance into account. The amount of reductions required is higher than the emission increase, resulting in a net benefit to the region as a whole and to most locations in the impacted area as well. This approach is usually coupled with a requirement to conduct an impact analysis to ensure that no significant increases occur in those areas where the effect of the increase is greater than the benefit from the decrease.

The analysis becomes much more complicated when the proposed reduction is of a different pollutant than that emitted by the proposed new source. The principle is the same: a net air quality benefit must be demonstrated. However, when the offsetting pollutant is different than the new pollutant, the demonstration is not straightforward.

Although the statutory requirement is to show an overall net air quality benefit, the practice has been to apply this test on a pollutant-specific basis. The agencies have allowed the reduction of one pollutant to offset the increase of another pollutant only where the two pollutants can be related, generally because one pollutant is a precursor for the other, or both are precursors for a third pollutant.

The SJVAPCD is not in attainment with the state 24-hour standard for PM_{10}. The District's new source review rule requires offsets for most increases in emissions of PM_{10} and its precursors, which include NOx, SO_2, VOC, and PM_{10}. The LEC project will be required to provide offsets for all of these pollutants. NCPA has purchased NOx, SO_2, VOC, and PM_{10} offsets. However, the applicant has not been able to obtain sufficient PM_{10} offsets to fully offset project PM_{10} with PM_{10} reductions.

SJVAPCD allows the use of interpollutant offsets, provided the project demonstrates a net air quality benefit and the impact analysis demonstrates that the project does not worsen or cause non-compliance with any ambient air quality standard. NCPA has proposed to meet the PM_{10} offset requirements for the LEC project by providing both direct PM_{10} and interpollutant SO_2 reductions. The direct impact analysis requirement, which demonstrated that the PM_{10} emissions from the proposed project would not contribute significantly to an existing violation, was addressed in Section 5.1.2.5. <u>NCPA proposes to follow the District's March 2009 guidance (attached) and to provide SO_2 reductions at a 1.0:1.0 ratio (not including the distance ratio requirement in Rule 2201).</u>

Interpollutant Offset Ratio Explanation

The Air District's Rule 2201, "New and Modified Source Review", requires facilities to supply "emissions offsets" when a permittee requests new or modified permits that allow emissions of air contaminants above certain annual emission offset thresholds. In addition, Rule 2201 allows interpollutant trading of offsets amongst criteria pollutants and their precursors upon the appropriate scientific demonstration of an adequate trading ratio, herein referred to as the interpollutant ratio. A technical analysis is required to determine the interpollutant offset ratio that is justified by evaluation of atmospheric chemistry. This evaluation has been conducted using the most recent modeling analysis available for the San Joaquin Valley. The results of the analysis are designed to be protective of health for the entire Valley for the entire year, by applying the most stringent interpollutant ratio throughout the Valley.

It is appropriate for District particulate offset requirements to be achieved by either a reduction of directly emitted particulate or by reduction of the gases, called particulate precursors, which become particulates from chemical and physical processes in the atmosphere. The District interpollutant offset relationship quantifies precursor gas reductions sufficient to serve as a substitute for a required direct particulate emissions reduction. Emission control measures that reduce gas precursor emissions at the facility may be used to provide the offset reductions. Alternatively, emission credits for precursor reductions may be used in accordance with District regulations.

The amount of particulate formed by the gaseous emissions must be evaluated to determine how much credit should be given for the gaseous reductions. Gases combine and merge with other material adding molecular weight when forming into particles. Some of the gases do not become particulate matter and remain a gas. Both the extent of conversion into particles and resulting weight of the particles are considered to establish mass equivalency between direct particulate emissions and particulate formed from gas precursors. The Interpollutant offset ratio is expressed as a per-ton equivalency.

The District interpollutant analysis uses the most recent and comprehensive modeling of San Joaquin Valley particulate formation from sulfur oxides (SOx) and nitrogen oxides (NOx). Modeling compares industrial directly emitted particulate to particulate matter from precursor emissions. The interpollutant modeling procedure, assumptions and uncertainties are documented in an extensive analysis file. Additional documentation of the modeling procedure for the San Joaquin Valley is contained in the 2008 PM2.5 Plan and its appendices. The 2008 PM2.5 Plan provides evaluation of the atmospheric relationships for direct particulate emissions and precursor gases when they are highest during the fourth quarter of the year. The southern portion of the Valley is evaluated by both receptor modeling and regional modeling of chemical relationships for precursor particulate formation. Regional modeling was conducted for the entire Valley through 2014. The two modeling approaches are combined to determine interpollutant offset ratios applicable to, and protective of, the entire Valley (SOx for PM 1:1 and NOx for PM 2.629:1).

DEVELOPMENT OF THE INTERPOLLUTANT RATIO

For the proposed substitution of reductions of sulfur oxides (SOx) or nitrogen oxides (NOx) for directly emitted particulate matter

March 2009

Introduction

Goal of Interpollutant Evaluation: Establish the atmospheric exchange relationship for substitution of alternative pollutant or precursor reductions for required reductions of directly emitted particulate

Evaluation to establish the atmospheric relationship of different pollutants is required as a prerequisite for establishing procedures for allowing a required reduction to be met by substitution of a reduction of a different pollutant or pollutant precursor. Proposed new facility construction or facility modifications may result in increased emissions of a pollutant. The District establishes requirements for reductions of the pollutant to “offset” the proposed increase. A facility may propose a reduction of an alternative pollutant or pollutant precursor where reductions of that material have already been achieved at the facility beyond the amount required by District regulations or where emission reductions credits for reductions achieved by other facilities are economically available; however, for such a substitution to be allowed the District must establish equivalency standards for the substitution. The equivalency relationship used for offset requirements is referred to in this discussion as the interpollutant ratio. The interpollutant ratio is a mathematical formula expressing the amount of alternative pollutant or precursor reduction required to be substituted for the required regulatory reduction. This discussion is limited to the atmospheric relationships and does not address other policy or regulatory requirements for offsets such as are contained in District Rule 2201.

The following description is provided to explain key elements of the analysis conducted to develop the atmospheric relationship between the commonly requested substitutions. Emission reductions of sulfur oxide emissions or nitrogen oxide emissions are proposed by many facilities as a substitution for reduction of directly emitted particulates. Elemental and organic carbon emissions are the predominant case and dominant contribution to directly emitted particulate mass from industrial facilities, although other types of directly emitted particulates do occur. Therefore this atmospheric analysis examines directly emitted carbon particulates from industrial sources in comparison to the formation of particles from gaseous emissions of sulfur oxides and nitrogen oxides.

Analyses included in Interpollutant evaluation

Factors Considered

The foundation for this analysis is provided by the atmospheric modeling conducted for the 2008 PM2.5 Plan. Modeling conducted for this State Implementation Plan was conducted by the District and the California Air Resources Board using a variety of modeling approaches. Each separate model has technical limitations and uncertainties. To reduce the uncertainty of findings, a combined evaluation of results of all of the modeling methods is used to establish "weight of evidence" support for technical analysis and conclusions. The modeling methods are supported by a modeling protocol which was sent to ARB and EPA Region IX for review and was included in the appendices to the Plan.

The analysis file prepared for the interpollutant ratio evaluation includes emissions inventories, regional model daily output files, chemical mass balance modeling and speciated rollback modeling as produced for the 2008 PM2.5 Plan. This well examined and documented modeling information was used as a starting point for additional evaluation to determine interrelationships between directly emitted pollutants and particulates from precursors.

The interpollutant ratio analysis is limited to evaluation of directly emitted PM2.5 from industrial sources and formation of PM2.5 from precursor gases. While both directly emitted particulates and particulate from precursor gases also occur in the PM10 size range, there is much more uncertainty associated with deposition rates and particle formation rates for the larger size ranges. Additionally, because PM2.5 is a subset of PM10; all reductions of PM2.5 are fully creditable as reductions towards PM10 requirements. This analysis concentrates on the quarter of the year when both directly emitted carbon from industrial sources and secondary particulates are measured at the highest levels. Assessing atmospheric ratios at low concentrations is subject to much greater uncertainty and has limited value toward assessment of actions to comply with the air quality standards.

Elements from 2008 PM 2.5 Plan

- Regional modeling daily output for eleven locations
- Chemical Mass Balance (CMB) modeling for four locations – source analysis, speciation profile selection, event meteorology evaluation
- Receptor speciated rollback modeling with adjustment for nitrate nonlinearity for four locations, evaluation of spatial extent of contributing sources
- Emission inventories and projections to future years as developed for the 2008 PM 2.5 Plan

- Modeling protocols for receptor modeling, regional modeling, and Positive matrix Factorization (PMF) analysis and evaluation of technical issues applicable to particulate formation in the San Joaquin Valley
- Model performance analysis as documented in appendices to the 2008 PM 2.5 Plan

Extension by additional analysis

Additional evaluation was conducted to evaluate the receptor modeling relationship between direct PM from industrial sources and sulfate and nitrate particulate formed from SOx and NOx precursor gases. Area of influence adjustments were evaluated to ensure appropriate consideration of contributing source area for different types of pollutants for both directly emitted and secondary particulate. This evaluation was possible only for the southern four Valley counties and was conducted for both 2000 and 2009.

The regional model output was evaluated for the fourth quarter to evaluate general atmospheric chemistry in 2005 and 2014 to determine the correlation between northern and southern areas of the Valley. This evaluation determined that the atmospheric chemistry observed and modeled in the north was within the range of values observed and modeled in the southern SJV. This establishes that a ratio protective of the southern Valley will also be protective in the north.

The District determined from the additional analyses of both receptor and regional modeling that the most stringent ratio determined for the southern portion of the Valley would also be protective of the northern portion of the Valley. Due to the regional nature of these pollutants, actions taken in other counties must be assumed to have at least some influence on other counties; therefore to achieve attainment at the earliest practical date it is appropriate to require all counties to establish a consistent interpollutant ratio for the entire District.

Strengths

The interpollutant ratio analysis uses established and heavily reviewed modeling and outputs as foundation data. Analysis of model performance has already been completed for the models and for the emissions inventories used for this analysis. The modeling was performed in accordance with protocols developed by the District and ARB and in accordance with modeling guidelines established by EPA. The combination of modeling approaches provides an analysis for the current year and provides projection to 2014. Weight of evidence comparison of various modeling approaches establishes the reliability of the foundation modeling, with all modeling approaches showing strong agreement in predicted results. Additional analysis performed to develop the interpollutant ratio uses both regional and receptor evaluations which were the primary models used for the 2008 PM 2.5 Plan.

Limitations

Both industrial direct emissions and secondary formed particulate may be both PM2.5 and PM10. The majority of secondary particulates formed from precursor gases are in the PM2.5 range as are most combustion emissions from industrial stacks, however both secondary and stack emissions do contain particles larger than PM2.5. Regional modeling is more reliable for the smaller fraction due to travel distances and deposition rates. Large particles have much higher deposition and are much more difficult to replicate with a regional model. This leads to a strong technical preference for evaluating both emission types in terms of PM2.5 because the integration of receptor analysis and regional modeling for coarse particle size range up to PM10 has a much greater associated uncertainty.

Analyses contained in Receptor modeling

Factors Considered

This modeling approach uses speciated linear modeling based on chemical mass balance evaluation of contributing sources with San Joaquin Valley specific identification of contributing source profiles, adjustments from regional modeling for the nonlinearity of nitrate formation, adjustments for area of influence impacts of contributing sources developed from back trajectory analysis of high concentration particulate episodes and projections of future emission inventories as developed for the 2008 PM2.5 Plan.

Analyses in receptor modeling that use input from regional modeling

The receptor modeling analysis uses a modified projection of nitrate particulate formation from nitrogen oxides based upon results of regional modeling. The atmospheric chemistry associated with nitrate particulate formation has been determined to be nonlinear; while the default procedures for speciated rollback modeling assume a linear relationship. This adjustment has been demonstrated as effective in producing reliable atmospheric projections for the prior PM10 Plans.

Extension by additional analysis

Additional evaluations were added to results of the receptor modeling performed for the 2008 PM2.5 Plan. Calculations determine the observed micrograms per ton of emission for each contributing source category that can be resolved by chemical mass balance modeling methods. These ten categories allow differentiation of industrial direct emissions of organic and elemental carbon from other sources that emit elemental and organic carbon. The interpollutant calculation is developed as an addition to the receptor analysis by calculating the ratio of emissions per ton of directly emitted industrial PM2.5 to the per ton ratio of secondary particulate formed from NOx and SOx emissions. Summary tables and issue and documentation discussion was added to the analysis.

Strengths

Receptor modeling provides the ability to separately project the effect of different key sources contributing to carbon and organic carbon. This is critical for establishing the atmospheric relationship between industrial emissions and the observed concentrations due to industrial emissions. Regional modeling methods at this time do not support differentiation of vegetative and motor vehicle carbon contribution from the emissions form industrial sources. The area of influence of contributing sources was also considered as a factor with the methods developed by the District to incorporate the gridded footprint of contributing sources into the receptor analysis. While regional models use gridded emissions, current regional modeling methods do not reveal the resulting area of influence of contributing sources.

Limitations

Receptor modeling uses linear projections for future years and cannot account for equilibrium limitations that would occur if a key reaction became limited by reduced availability of a critical precursor due to emission reductions. The regional model was used to investigate this concern and did not project any unexpected changes due to precursor limitations.

Analyses contained in Regional modeling

Factors Considered

The analysis file includes the daily modeling output representing modeled values for the base year 2005 and predicted values for 2014 for each of the eleven Valley sites that have monitoring data for evaluation of the models performance in predicting observed conditions. These sites are located in seven of the eight Valley counties. Madera County does not have monitoring site data for this comparison.

Modeling data for all quarters of the year was provided. Due to the higher values that occur due to stagnation events in the fourth quarter, both industrial carbon concentrations and secondary particulates forming from gases are highest in the fourth quarter. Evaluating the interpollutant ratio for other quarters would be less reliable and of less significance to assisting in the reduction of high particulate concentrations. Modeling for lower values has higher uncertainty. Modeling atmospheric ratios when the air quality standard is being met are axiomatically not of value to determining offset requirements intended to assist in achieving compliance with the air quality standard. However, for consistency of analysis between sites, days when the standard was being met during the fourth quarter were not excluded from the interpollutant ratio analysis. Bakersfield fourth quarter modeled data included only eight days that were at or below the standard. Fresno and Visalia sites averaged twelve days; northern sites 24 days and the County of Kings 38 days.

Modeling output provided data for both 2005 and 2014. While there is substantial emissions change projected for this period, the regional modeling evaluation does not project much change in the atmospheric ratios of directly emitted pollutants and secondary pollutants from precursor gases. This indicates that the equilibrium processes are not expected to encounter dramatic change due to limitation of reactions by scarcity of one of the reactants. This further justifies using the receptor evaluation determining the interpollutant ratio for 2009 through the year 2014 without further adjustment. If observed air quality data demonstrates a radical shift in chemistry or components during the next few years, such a change could indicate that a limiting reaction has been reached that was not projected by the model and such radical changes might require reassessment of the conclusion that the ratio should remain unchanged through 2014.

Extension by additional analysis

Regional modeling results prepared for the 2008 PM2.5 Plan were analyzed to extract fourth quarter data for all sites. The atmospheric chemistry for all counties was analyzed for consistency and variation. This analysis provided a determination that the secondary formation chemistry and component sources contributing to concentrations observed in the north fell within the range of values similarly determined for the southern four counties. Based upon examination of the components and chemistry, the northern counties would be expected to have an interpollutant ratio value less than the ratio determined for Kern County but greater than the one for Tulare County. This establishes that the interpollutant ratio determined by receptor analysis of the southern four counties provides a value that is also sufficiently protective for the north.

Strengths

Regional models provide equilibrium based evaluations of particulate formed from precursor gases and provide a regional assessment that covers the entire Valley. The projection of particulate formed in future years is more reliable than linear methods used for receptor modeling projections.

Limitations

The regional model does not provide an ability to focus on industrial organic carbon emissions separate from other carbon sources such as motor vehicles, residential wood smoke, cooking and vegetative burning. Regional modeling does not provide an assessment method for determination of sources contributing at each site or the area of influence of contributing emissions. Receptor analysis provides a more focused tool for this aspect of the evaluation.

Results and Documentation

SJVAPCD Interpollutant Ratio Results

SOx for PM ratio: 1.000 ton of SOx per ton of PM

NOx for PM ratio: 2.629 tons of NOx per ton of PM

These ratios do not include adjustments for other regulatory requirements specified in provisions of District Rule 2201.

The results of the modeling analysis developed an atmospheric interpollutant ratio for NOx to PM of 2.629 tons of NOx per ton of PM. This result was the most stringent ratio from the assessment industrial carbon emissions to secondary particulates at Kern County; with Fresno, Tulare and Kings counties having a lower ratio. The assessment of chemistry from the regional model required comparison of total carbon to secondary particulates and is therefore not directly useful to establish a ratio. However, the regional model does provide an ability to compare the general atmospheric similarity and compare changes in chemistry due to Plan reductions. Evaluation revealed that the atmospheric chemistry of San Joaquin, Stanislaus and Merced counties falls within the range of urban characteristics evaluated for the southern four counties; therefore the ratio established should be sufficiently protective of the northern four counties. Additionally, comparison of future year chemistry showed minimal change in pollutant ratio due to the projected changes in the emission inventory from implementation of the Plan. The SOx ratio as modeled indicates a value of less than one to one due to the increase in mass for conversion of SOx to a particulate by combination with other atmospheric compounds; however, the District has set guidelines that require at least one ton of an alternative pollutant for each required ton of reduction in accordance with District Rule 2201 Section 4.13.3. Therefore the SOx interpollutant ratio is established as 1.000 ton of SOx per ton of PM. These ratios do not include adjustments for other regulatory considerations, such as other provisions of District Rule 2201.

A guide to the key technical topics and the reference material relevant to that topic is found on the next page. References from the 2008 PM2.5 Plan may be obtained by requesting a copy of that document and its appendices or by downloading the document from http://www.valleyair.org/Air_Quality_Plans/AQ_Final_Adopted_PM25_2008.htm. References in Italics are spreadsheets included in the interpollutant analysis file "09 Interpollutant Ratio Final 032909.xls" which includes 36 worksheets of receptor modeling information from the 2008 PM2.5 Plan, 11 modified and additional spreadsheets for this analysis and two spreadsheets of regional model daily output. This file is generally formatted for printing with the exception of the two spreadsheets containing the regional model output "*Model-Daily Annual*" and "*Model-Daily Q4*" which are over 300 pages of raw unformatted model output files. The remainder of the file is formatted to print at approximately 100 pages. This file will be made available on request but is not currently posted for download.

Interpollutant Ratio Issues & Documentation

	TOPIC	Reference
1	**Reason for using PM2.5 for establishing the substitution relationship between direct emitted carbon PM and secondary nitrate and sulfate PM:** consistency of relationship between secondary particulates and industrial direct carbon combustion emissions.	2008 PM2.5 Plan, Sections 3.3.2 through 3.4.2
2	**Reason for using 4th Quarter analysis:** Highest PM2.5 for all sites.	*DV Qtrs*
3	**Reason for using analysis of southern SJV sites to apply to regional interpollutant ratio:** Northern site chemistry ratios are within the range of southern SJV ratios. Peak ratio will be protective for all SJV counties.	*Q4 Model Pivot, Model-site chem, Model-Daily Q4*
4	**Reason for using combined results of receptor and regional model:** Receptor model provides breakdown of different carbon sources to isolate connection between industrial emissions and secondary PM. Regional model provides atmospheric information concerning the northern SJV not available from receptor analysis.	2008 PM2.5 Plan, Appendix F 2008 PM2.5 Plan, Appendix G
5	**Most significant contributions of receptor evaluation:** Separation of industrial emissions from other source types. Area of influence evaluation for contributing sources.	2008 PM2.5 Plan, Appendix F
6	**Most significant contributions of regional model:** Scientific equilibrium methods for atmospheric chemistry projections for 2014. Receptor technique is limited to linear methods.	2008 PM2.5 Plan, Appendix G
7	**Common area of influence adjustments used for all receptor evaluations:** Geologic & Construction, Tire and Brake Wear, Vegetative Burning - contribution extends from more than just the urban area (L2) Mobile exhaust (primary), Organic Carbon (Industrial) primary, Unassigned - contribution extends from more than larger area, subregional (L3) Secondary particulates from carbon sources are dominated by the local area with some contribution from the surrounding area (average of L1 and L2) Marine emissions not found present in CMB modeling for this analysis.	Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* County *2000-2009* worksheets
8	**Variations to reflect secondary area of influence specific to location:** Fresno: Evaluation shows extremely strong urban signature (L1) for secondary sources Kern: Evaluation shows a strong urban signature mixed with emissions from the surrounding industrial areas (average L1 and L2) for both carbon and secondary sources Kings and Tulare: Prior evaluation has show a shared metropolitan contribution area (L2)	Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* County *2000-2009* worksheets
9	**Reasons for using 2009 Interpollutant Ratio Projection:** 2009 Interpollutant ratio is consistent with current emissions inventories Regional modeling does not show a significant change in chemical relationships through 2014.	2008 PM2.5 Plan *Q4 Model Pivot*
10	**Reason for using SOx Interpollutant Ratio at 1.000:** A minimum offset ratio is established as 1.000 to 1.000 consistent with prior District policy and procedure for interpollutant offsets.	District Rule 2201 Section 4.13.3

APPENDIX 5.1G

Revised July 2009

Cumulative Impacts Analysis for the LEC

APPENDIX 5.1G (REVISED JULY 2009)

Cumulative Impacts Analysis for the LEC

Cumulative air quality impacts from the LEC and other reasonably foreseeable projects will be both regional and localized in nature. Regional air quality impacts are possible for pollutants such as ozone, which is formed through a photochemical process that can take hours to occur. Carbon monoxide, NOx, and SOx impacts are generally localized in the area in which they are emitted. PM_{10} can create a local air quality problem in the vicinity of its emission source, but can also be a regional issue when it is formed in the atmosphere from VOC, SOx, and NOx.

The cumulative impacts analysis considers the potential for both regional and localized impacts due to emissions from proposed operation of LEC. Regional impacts are evaluated by comparing maximum daily and annual emissions from LEC with emissions of ozone and PM_{10} precursors in both San Joaquin County and the entire San Joaquin Valley. Localized impacts are evaluated by looking at other local sources of pollutants that are not included in the background air quality data to determine whether these sources in combination with LEC would be expected to cause significant cumulative air quality impacts.

Regional Impacts

Regional impacts are evaluated by assessing LEC's contribution to regional emissions. Although the relative importance of VOC and NOx emissions in ozone formation differs from region to region and from day to day, state law requires reductions in emissions of both precursors to reduce overall ozone levels. The change in the sum of emissions of these pollutants, equally weighted, provides a rough estimate of the impact of LEC on regional ozone levels.[1] Similarly, a comparison of the emissions of PM_{10} precursor emissions from LEC with regional PM_{10} precursor emissions provides an estimate of the impact of LEC on regional PM_{10} levels.

Under SJVAPCD regulations, LEC will be required to provide offsets for increases in NOx, VOC, SO_2, and PM_{10} emissions from the project above certain regulatory thresholds. Regulatory offset requirements are calculated based on quarterly emissions, but the regional inventories are expressed in tons per day of emissions. Comparisons are shown on both a daily and annual basis.

Tables 5.1G-1R and 5.1G-2R summarize these comparisons. LEC emissions are compared with regional emissions in 2012, as that is the year the project is expected to begin operation. San Joaquin County and SJVAPCD emissions projections for 2012 were estimated by averaging the projected emissions inventories for 2010 and 2015 obtained from the Air Resources Board's web-based emission inventory projection software, available at *www.arb.ca.gov/app/emsinv/emssumcat2007.php.*

[1] LEC is proposing to use direct, and not interpollutant, offsets for most ozone precursors.~~, so a~~All NOx emissions and a very small portion of VOC emissions from the project will be offset using NOx ERCs while ~~all~~ most of the VOC emissions will be offset using VOC ERCs.

Localized Impacts

To evaluate potential cumulative impacts of LEC in combination with other projects in the area, projects within a radius of 10 km (6 miles) of the project were used for the cumulative impacts analysis.

Within this search area, three categories of projects with combustion sources were used as criteria for identification:

- Existing projects that have been in operation since at least 2007;
- Projects for which air pollution permits to construct have been issued and that began operation after July 1, 2007; and
- Projects for which air pollution permits to construct have not been issued, but that are reasonably foreseeable.

Existing projects that have been in operation since at least 2007 are reflected in the ambient air quality data that has been used to represent background concentrations; consequently, no further analysis of the emissions from this category of facilities was performed. The cumulative impacts analysis adds the modeled impacts of selected facilities to the maximum measured background air quality levels, thus ensuring that these existing projects are taken into account.

Projects for which air pollution permits to construct have been issued but that were not operational in 2007 were identified through a request of permit records from the San Joaquin Valley APCD. Projects that had a permit to construct issued after July 1, 2007, would be included in the cumulative air quality impacts analysis. However, as indicated in the District's response to our request for information about potential projects (copy attached), there are no projects that meet these criteria. Therefore, the cumulative impacts analysis includes only the existing NCPA Lodi STIG turbine and emergency Diesel fire pump engine, along with the LEC. Table 5.1G-3R provides the emission rates and stack parameters used in the cumulative impacts analysis. The modeling results are summarized in Table 5.1G-4R. The modeling indicates that the maximum modeled impacts from the old and new plants overlap very little, if at all.

Table 5.1G-1R
NCPA Lodi Energy Center
Regional Cumulative Impacts Analysis: Ozone Precursors
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

	2012 San Joaquin County Inventory Emissions, tons/day		**2012 SJVAPCD Inventory Emissions, tons/day**		**2012 San Joaquin County Inventory Emissions, tons/yr**		**2012 SJVAPCD Inventory Emissions, tons/yr**	
	NOx	**VOC**	**NOx**	**VOC**	**NOx**	**VOC**	**NOx**	**VOC**
Source Category								
Stationary Sources	17.7	7.8	105.4	81.7	6,450.1	2,839.5	38,480.3	29,813.2
Area-Wide Sources	1.7	16.1	17.5	156.1	622.7	5,858.6	6,393.5	56,974.3
Mobile Sources	64.0	20.5	367.0	112.9	23,367.5	7,473.6	133,952.4	41,198.1
Total by Pollutant	83.4	44.3	489.9	350.6	30,440.3	16,171.7	178,826.3	127,985.6
Total Ozone Precursors	127.7		840.6		46,612.0		306,811.9	
LEC Emissions								
LEC Emissions by Pollutant	0.444	0.084	0.444	0.084	76.3	16.8	76.3	16.8
Total LEC Ozone Precursors	0.53		0.53		93.1		93.1	
LEC Ozone Precursors as Percent of Regional Total	0.41%		0.06%		0.20%		0.03%	
Reductions from ERCs	0.314	0.069	0.314	0.069	114.7	25.0	114.7	25.0
LEC Net Increase	0.129	0.015	0.129	0.015	-38.3	-8.2	-38.3	-8.2
Remaining LEC Ozone Precursors	0.14		0.14		-46.6		-46.6	
Remaining LEC Ozone Precursors as Percent of Regional Total	0.11%		0.02%		0.00%		0.00%	

Table 5.1G-2
NCPA Lodi Energy Center
Regional Cumulative Impacts Analysis:
PM10 Precursors
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

	2012 San Joaquin County Inventory Emissions, tons/day				**2012 SJVAPCD Inventory Emissions, tons/day**			
	NOx	**VOC**	**SO2**	**PM10**	**NOx**	**VOC**	**SO2**	**PM10**
Source Category								
Stationary Sources	17.7	7.8	4.9	2.9	105.4	81.7	23.0	24.7
Area-Wide Sources	1.7	16.1	0.1	26.8	17.5	156.1	1.1	248.2
Mobile Sources	64.0	20.5	0.7	3.5	367.0	112.9	2.0	20.5
Total by Pollutant	83.4	44.3	5.6	33.2	489.9	350.6	26.1	293.4
Total PM10 Precursors	166.6				1160.0			
LEC Emissions								
LEC Emissions by Pollutant	0.444	0.084	0.074	0.123	0.444	0.084	0.074	0.123
Total LEC PM10 Precursors	0.72				0.72			
LEC PM10 Precursors as Percent of Regional Total	0.43%				0.06%			
Reductions from ERCs	0.314	0.069	0.136	0.043	0.314	0.069	0.136	0.043
LEC Net Increase	0.129	0.015	-0.062	0.080	0.129	0.015	-0.062	0.080
Remaining LEC PM10 Precursors	0.16				0.16			
Remaining LEC PM10 Precursors as Percent of Regional Total	0.10%				0.01%			

Table 5.1G-2 (cont'd)
NCPA Lodi Energy Center
Regional Cumulative Impacts Analysis:
PM10 Precursors
Rev 07/09 Siemens SCC6-5000F 1x1, n

	2012 San Joaquin County Inventory Emissions, tons/yr				2012 SJVAPCD Inventory Emissions, tons/yr			
	NOx	**VOC**	**SO2**	**PM10**	**NOx**	**VOC**	**SO2**	**PM10**
Source Category								
Stationary Sources	6,450.1	2,839.5	1,772.8	1,057.8	38,480.3	29,813.2	8,386.1	9,012.6
Area-Wide Sources	622.7	5,858.6	37.0	9,778.2	6,393.5	56,974.3	411.4	90,598.7
Mobile Sources	23,367.5	7,473.6	252.0	1,284.4	133,952.4	41,198.1	720.5	7,471.0
Total by Pollutant	30,440.3	16,171.7	2,061.9	12,120.4	178,826.3	127,985.6	9,517.9	107,082.2
Total PM10 Precursors	60,794.2				423,412.0			
LEC Emissions								
LEC Emissions by Pollutant	76.3	16.8	26.9	44.1	76.3	16.8	26.9	44.1
Total LEC PM10 Precursors	164.1				164.1			
LEC PM10 Precursors as Percent of Regional Total	0.27%				0.04%			
Reductions from ERCs	114.66	25.03	49.74	15.60	114.66	25.03	49.74	15.60
LEC Net Increase	-38.35	-8.22	-22.81	28.46	-38.35	-8.22	-22.81	28.46
Remaining LEC PM10 Precursors	-40.91				-40.91			
Remaining LEC PM10 Precursors as Percent of Regional Total	0.00%				0.00%			

Table 5.1G-3R
NCPA Lodi Energy Center
Emission Rates and Stack Parameters for Cumulative Impacts Modeling
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

	Stack Diam, m	Release Height m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rates, g/s NOx	SO2	CO	PM10
Averaging Period: One hour									
LEC Gas Turbine	6.706	45.720	358.56	559.263	15.836	1.9576	0.7685	1.7878	n/a
LEC Aux Boiler	0.762	19.812	421.89	5.101	11.186	0.0387	1.311E-02	1.685E-01	n/a
Existing Lodi CT #2	2.788	28.042	682.44	316.972	51.934	0.6552	1.633E-01	1.6905	n/a
Existing Lodi Fire Pump Engine	0.127	4.572	714.11	1.018	80.386	0.2038	1.575E-03	1.010E-01	n/a
Averaging Period: Three hours									
LEC Gas Turbine	6.706	45.720	358.56	559.263	15.836	n/a	0.7685	n/a	n/a
LEC Aux Boiler	0.762	19.812	421.89	5.101	11.186	n/a	1.311E-02	n/a	n/a
Existing Lodi CT #2	2.788	28.042	682.44	316.972	51.934	n/a	1.633E-01	n/a	n/a
Existing Lodi Fire Pump Engine	0.127	4.572	714.11	1.018	80.386	n/a	1.575E-03	n/a	n/a
Averaging Period: Eight hours									
LEC Gas Turbine	6.706	45.720	358.56	559.263	15.836	n/a	n/a	85.4970	n/a
LEC Aux Boiler	0.762	19.812	421.89	5.101	11.186	n/a	n/a	1.685E-01	n/a
Existing Lodi CT #2	2.788	28.042	682.44	316.972	51.934	n/a	n/a	1.6905	n/a
Existing Lodi Fire Pump Engine	0.127	4.572	714.11	1.018	80.386	n/a	n/a	1.010E-01	n/a
Averaging Period: 24 hours, PM10									
LEC Gas Turbine	6.706	45.720	352.44	355.681	10.072	n/a	n/a	n/a	1.1340
LEC Aux Boiler	0.762	19.812	421.89	5.101	11.186	n/a	n/a	n/a	0.0353
Cooling Tower (per cell, 7 cells)	8.534	13.960	304.56	78.208	7.498	n/a	n/a	n/a	1.676E-02
Existing Lodi CT #2	2.788	28.042	682.44	316.972	51.934	n/a	n/a	n/a	0.2520
Existing Lodi Fire Pump Engine	0.127	4.572	714.11	1.018	80.386	n/a	n/a	n/a	0.0333
Averaging Period: 24 hours, SO2									
LEC Gas Turbine	6.706	45.720	358.56	559.263	15.836	n/a	0.7685	n/a	n/a
LEC Aux Boiler	0.762	19.812	421.89	5.101	11.186	n/a	1.311E-02	n/a	n/a
Existing Lodi CT #2	2.788	28.042	682.44	316.972	51.934	n/a	1.633E-01	n/a	n/a
Existing Lodi Fire Pump Engine	0.127	4.572	714.11	1.018	80.386	n/a	1.575E-03	n/a	n/a
Averaging Period: Annual									
LEC Gas Turbine	6.706	45.720	359.67	511.757	14.491	2.1776	0.7685	n/a	1.1340
LEC Aux Boiler	0.762	19.812	421.89	5.101	11.186	1.768E-02	5.988E-03	n/a	1.611E-02
Cooling Tower (per cell, 7 cells)	8.534	13.960	304.56	78.208	7.498	n/a	n/a	n/a	1.676E-02
Existing Lodi CT #2	2.788	28.042	682.44	316.972	51.934	6.552E-01	1.633E-01	n/a	0.252
Existing Lodi Fire Pump Engine	0.127	4.572	714.11	1.018	80.386	2.327E-03	1.798E-05	n/a	1.899E-04

TABLE 5.1G-4R
Modeled Maximum Cumulative Project Impacts

Pollutant	Averaging Time	Maximum Localized Impacts (µg/m³) LEC Alone	Existing Facility	Total	Background (µg/m³)	Total Impact (µg/m³)	State Standard (µg/m³)	Federal Standard (µg/m³)
NO_2[a]	1-hour	~~27.5~~ 28.5	~~152.7~~ 143.6	~~152.8~~ 144.2	163.6	~~316.4~~ 307.8	338	–
	Annual	~~0.3~~ 0.6	0.1	~~0.3~~ 0.7	34.0	~~34.3~~ 34.7	–	100
SO_2	1-hour	~~10.4~~ 3.8	~~9.1~~ 1.1	~~10.4~~ 3.9	46.8	~~57.2~~ 50.7	650	–
	3-hour	~~7.6~~ 2.4	~~7.4~~ 0.9	~~7.6~~ 2.5	28.6	~~36.2~~ 31.1	–	1300
	24-hour	~~2.9~~ 1.4	~~3.3~~ 0.4	~~3.3~~ 1.5	10.8	~~14.1~~ 11.3	109	365
	Annual	~~0.1~~ 0.2	0.02	~~0.1~~ 0.2	2.7	~~2.8~~ 2.9	–	80
CO	1-hour	~~324~~ 337	~~176~~ 71	~~324~~ 340	5,500	~~5,824~~ 5,840	23,000	40,000
	8-hour	~~111~~ 110	~~100~~ 49.5	112	3,178	3,290	10,000	10,000
PM_{10}	24-hour	3.7	~~20.7~~ 8.4	~~21.7~~ 9.1	85	~~106.7~~ 94.1	50	150
	Annual	~~0.9~~ 0.6	0.02	~~0.9~~ 0.6	33.4	~~34.3~~ 34.0	20	--
$PM_{2.5}$	24-Hour	3.7	~~20.7~~ 8.4	~~21.7~~ 9.1	48	~~69.7~~ 57.1	–	35
	Annual	~~0.9~~ 0.6	0.02	~~0.9~~ 0.6	13.1	~~14.0~~ 13.7	12	15

Notes:

a. Ozone limiting method applied for 1-hour average, using concurrent O_3 data.

Appendix E
Revised Public Health Appendix

Screening Health Risk Assessment—Revised

The screening health risk assessment for the project has been revised to reflect the proposed project changes, including changes in fuel use and resulting emissions, stack parameters and plant layout. As in the original risk assessment, emissions of non-criteria pollutants from the project were estimated using emission factors approved by the SJVAPCD, CARB, and EPA. Air dispersion modeling combined the emissions with site-specific terrain and meteorological conditions to estimate short-term and long-term arithmetic mean concentrations in air for use in the health risk assessment. The EPA-recommended air dispersion model, AERMOD, was used along with five years (2000-2004) of compatible meteorological data assembled and provided by the staff of the SJVAPCD. The meteorological data combined surface measurements made at Stockton Metropolitan Airport with upper air data from Oakland Airport. For this revised risk assessment, CARB's HARP On-Ramp[1] was used to integrate the air dispersion modeling output from the required air dispersion model, AERMOD, with the risk calculations in the HARP risk module.[2]

Risk Analysis Method

The screening analysis for the criteria pollutant modeling analysis was performed using the AERMOD model, the 2000 through 2004 Stockton meteorological data, specific receptor grids, and the stack parameters for operating cases at three different ambient temperatures. The results of the screening modeling analysis (see revised Air Quality Appendix, Appendix D to this Supplement) were used to determine the maximum impact operating conditions in modeling the annual and 1-hour averaging periods, and these modeling results were used in determining cancer risk and chronic HHI, and acute HHI, respectively.

The inhalation cancer potency factors and RELs used to characterize health risks associated with modeled concentrations in air were updated to reflect the most recent values adopted by OEHHA and CARB, as reflected in the *Consolidated Table of OEHHA/CARB Approved Risk Assessment Health Values* (CARB, February 9, 2009). These updated values are presented in Table 5.9-5R.

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[1] HARP On-Ramp Version 1, accessed at http://www.arb.ca.gov/toxics/harp/downloads.htm.

[2] In the original SHRA that was presented in the AFC, a hybrid approach was used to integrate the HARP risk assessment procedures with the AERMOD model. However, now that use of the HARP On-Ramp is well-established, this revised risk assessment utilizes the HARP model directly.

TABLE 5.9-5R
Toxicity Values Used to Characterize Health Risks

Toxic Air Contaminant	Inhalation Cancer Potency Factor $(mg/kg\text{-}d)^{-1}$	Chronic Reference Exposure Level ($\mu g/m^3$)	Acute Reference Exposure Level ($\mu g/m^3$)
Acetaldehyde	0.010	140	470
Acrolein	—	0.35	2.5
Ammonia	—	200	3,200
Benzene	0.10	60	1,300
1,3-Butadiene	0.60	20	—
Ethylbenzene	0.0087	2,000	—
Formaldehyde	0.021	9	55
Hexane	—	7,000	—
Naphthalene	0.12	9.0	—
PAHs (as BaP for HRA)	3.9	—	—
Propylene	—	3,000	—
Propylene oxide	0.013	30	3.100
Toluene	—	300	37,000
Xylene	—	700	22,000

Source: CARB/OEHHA.

Characterization of Risks from Toxic Air Pollutants

The change in potential maximum cancer risk associated with concentrations in air estimated for the MIR location is shown in redline format in Table 5.9-6R. The change in predicted risk for the redesigned project is minimal. The maximum carcinogenic risk remains well below the 10×10^{-6} threshold of significance for emitting units determined by the District to be applying T-BACT.

TABLE 5.9-6R
Summary of Potential Health Risks

Receptor	Carcinogenic Risk [a] (per million)	Cancer Burden	Acute Health Hazard Index	Chronic Health Hazard Index
Maximum Incremental Cancer Risk (MICR) at PMI	0.45 ~~0.43~~	0	0.01 ~~0.05~~	0.006 ~~0.008~~
Maximally Exposed Individual Worker [b] (MEIW)	0.074 ~~0.045~~		n/a	n/a
Significance Level	10	1.0	1.0	1.0

[a]Derived (Adjusted) Method used to determine significance of modeled risks.

[b]The worker is assumed to be exposed at the work location 8 hours per day, instead of 24, 245 days per year, instead of 365, and for 40 years, instead of 70. Therefore, a 70 year-based chronic HHI is not applicable to a worker.

Because the calculated MICR for the project remains less than 1 in one million, the cancer burden for the project remains zero.

By definition, human health risks associated with emissions from the project cannot be higher elsewhere than at the location of the MICR. Therefore, the potential cancer risk elsewhere also would be lower than the maximum listed in Table 5.9-6R. Because the potential cancer burden listed in Table 5.9-6R is less than one, the emissions from the project would not be associated with any increase in cancer cases in the previously defined population.

The change in maximum potential acute non-cancer health hazard index associated with concentrations in air is shown in Table 5.9-6R. The acute non-cancer health hazard index for all target organs remains well below 1.0, the threshold of significance.

Similarly, the change in maximum potential chronic non-cancer health hazard index associated with concentrations in air is shown in Table 5.9-6R. The chronic non-cancer health hazard index remains well below 1.0, the threshold of significance.

Summary of Impacts

Results from the health risk assessment based on emissions modeling indicate that there will be no significant incremental public health risks from construction or operation of the proposed project. Results from criteria pollutant modeling for routine operations indicate that potential ambient concentrations of NO_2, CO, SO_2, and PM_{10} would not exceed ambient air quality standards, with the exception of the state PM_{10} and $PM_{2.5}$ standards. For these pollutants, existing 24-hour and annual average PM_{10} and $PM_{2.5}$ background concentrations already exceed applicable standards, while the project would not add a significant contribution. The ambient air quality standards protect public health with a margin of safety for the most sensitive subpopulations (Section 3.1).

Cumulative Effects

The assessment of potential cumulative impacts of TACs was also revised to reflect the proposed changes to the project, and these cumulative health risks are summarized in the Table 5.9-7R. These results show that the maximum cumulative cancer, acute and chronic risks from the new plant and the existing plant remain well below the levels that are considered significant.

TABLE 5.9-7R
Summary of Potential Cumulative Health Risks

Receptor	Carcinogenic Risk* (per million)	Acute Health Hazard Index	Chronic Health Hazard Index
Maximum Incremental Cancer Risk, LEC	0.45 ~~0.43~~	0.01 ~~0.05~~	0.006 ~~0.008~~
Maximum Incremental Cancer Risk, Existing NCPA Lodi Power Plant**	2.9 ~~4.1~~	0.004 ~~0.009~~	0.002 ~~0.003~~
Maximum Cumulative Combined Cancer Risk	2.9 ~~4.1~~	0.01 ~~0.05~~	0.01 ~~0.01~~
Significance Level	10	1.0	1.0

*Derived (Adjusted) Method used to determine significance of modeled risks. Residential (70-year) exposure shown.

** Changes to cancer risk for existing plant is due to change in fenceline and not to any changes in emissions or operating assumptions. Changes in HHIs result from use of updated RELs in this revised risk assessment.

Mitigation Measures

The project has been designed to minimize emissions and impacts. No additional mitigation measures are needed for the LEC TAC emissions because the potential air quality and public health impacts remain less than significant.

Table 5.9B-1/2R
NCPA Lodi Energy Center
Modeling Inputs for Health Risk Assessment for Existing STIG
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

	Emissions, g/s	
Compound	1-hr Avg	Annual Avg
Ammonia	1.95E+00	1.954323
Propylene	4.48E-02	4.48E-02
Acetaldehyde	2.33E-03	2.33E-03
Acrolein	3.73E-04	3.73E-04
Benzene	7.00E-04	7.00E-04
1,3-Butadiene	2.51E-05	2.51E-05
Ethylbenzene	1.87E-03	1.87E-03
Formaldehyde	4.14E-02	4.14E-02
Hexane	1.50E-02	1.50E-02
Naphthalene	7.58E-05	7.58E-05
PAHs (Note 1)	5.25E-05	5.25E-05
Benz(a)anthracene	9.06E-06	9.06E-06
Benzo(a)pyrene	5.57E-06	5.57E-06
Benzo(b)fluoranthene	4.53E-06	4.53E-06
Benzo(k)fluoranthene	4.41E-06	4.41E-06
Chrysene	1.01E-05	1.01E-05
Dibenz(a,h)anthracene	9.42E-06	9.42E-06
Indeno(1,2,3-cd)pyrene	9.42E-06	9.42E-06
Propylene Oxide	2.78E-03	2.78E-03
Toluene	7.58E-03	7.58E-03
Xylene	3.73E-03	3.73E-03

Table 5.9B-3R
NCPA Lodi Energy Center
Screening Health Risk Assessment Modeling Inputs for Existing Emergency Fire Pump Engine
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

Compound	Emissions, g/s	
	1-hr Avg	Annual Avg
Diesel Particulate Matter	3.326E-02	1.899E-04

Table 5.9B-4R
NCPA Lodi Energy Center
Stack Parameters for Cumulative Screening HRA
Rev 07/09 Siemens SCC6-5000F 1x1, no duct firing

Stack Parameters				
	Stack Diam (m)	Stack Ht (m)	Exhaust Temp (deg K)	Exhaust Velocity (m/s)
CTG/HRSG, Acute Impacts (Case 1)	6.706	45.720	358.556	15.836
CTG/HRSG, Chronic and Cancer Impacts (Case 5)	6.706	45.720	359.667	14.491
Auxiliary Boiler	0.762	19.812	421.889	11.186
Existing Lodi CT #2	2.788	28.042	682.444	51.934
Existing Lodi Fire Pump Engine	0.127	4.572	714.111	80.386

Appendix F
Updated Will Serve Letter

CITY COUNCIL
LARRY D. HANSEN, Mayor
PHIL KATZAKIAN, Mayor Pro Tempore
SUSAN HITCHCOCK
BOB JOHNSON
JOANNE MOUNCE

CITY OF LODI

PUBLIC WORKS DEPARTMENT
CITY HALL, 221 WEST PINE STREET / P.O. BOX 3006
LODI, CALIFORNIA 95241-1910
TELEPHONE (209) 333-6706 / FAX (209) 333-6710
EMAIL pwdept@lodi.gov
http://www.lodi.gov

BLAIR KING, City Manager
RANDI JOHL, City Clerk
D. STEPHEN SCHWABAUER, City Attorney
F. WALLY SANDELIN, Public Works Director

July 24, 2009

Ed Warner
NCPA Lodi Energy Center
661 Commerce Drive
Roseville, CA 95678

Subject: Agreement to Serve Recycled Water to NCPA

Subject to agreement of business terms, the City of Lodi has agreed to serve recycled water to NCPA's Lodi Energy Center (LEC). NCPA will be submitting a Supplement to the Application for Certification (AFC) with the California Energy Commission (CEC). The City of Lodi can supply the required 1800 acre feet of recycle water per year that is contained in the AFC Supplement.

The City of Lodi currently serves NCPA's STIG facility, the San Joaquin County Mosquito and Vector Control facility, and adjacent City owned agricultural land with recycled water. As discussed in a meeting held between NCPA and the City of Lodi on July 13, 2009, the City of Lodi has sufficient capacity to serve both the LEC plant as well as existing users even with the increased water need resulting from the change in equipment described in the AFC Supplement. This commitment will not adversely affect any existing or future planned recycled water users.

We trust that this addresses the CEC's request. If you need additional information please do not hesitate to contact me at (209) 333-6740.

Sincerely,

F Wally Sandelin

for Charles E. Swimley Jr., P.E.
Water Services Manager

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