November 1, 2013

Cosmo Buttaro
MassDEP Northeast Regional Office
205B Lowell Street
Wilmington, MA 01887
Cosmo.Buttaro@state.ma.us

RE: Application No.: NE-12-022, Transmittal No.: X254064, Comments on Draft PSD Permit and Proposed Air Quality Plan Approval for Footprint Power Salem Harbor Development LP

Dear Mr. Buttaro:

Conservation Law Foundation ("CLF") and the undersigned organizations and individuals hereby provide these comments on the draft Prevention of Significant Deterioration Permit, Proposed Air Quality Plan Approval and Proposed Section 61 Findings issued regarding the above-referenced project on September 9, 2013. These comments are intended to supplement the comments already submitted during the public hearing that was held on October 10, 2013. CLF also received additional information from the Department in response to a public records request on Monday, October 28, 2013, and additional information regarding the air dispersion modeling from Footprint Power Salem Harbor Development LP on Wednesday, October 30, 2013. CLF and the undersigned organizations and individuals may seek leave to provide supplemental comments based upon these materials after having the opportunity to fully review them.

I. The Permit and Application Do Not Properly Conduct BACT Analyses

MassDEP entered into an "Agreement for Delegation of the Federal Prevention of Prevention of Significant Deterioriation (PSD) Program by the United States Environmental Protection Agency, Region 1 to the Massachusetts Department of Environmental Protection" ("Delegation Agreement) on April 11, 2011. Exhibit 1. Under that Delegation Agreement, the MassDEP agreed to implement and enforce 40 C.F.R. 52.21 as of July 1, 2010 and with respect to PM2.5 increments, the amendments of October 20, 2010. Exhibit 1 at 1. In addition, the Delegation Agreement provides:

E. MassDEP will follow EPA policy, guidance, and determinations as applicable for implementing the federal PSD program, whether issued before or after the execution of this Delegation Agreement, including:

1. PSD policy, guidance, and determinations issued by EPA. EPA will provide MassDEP with copies of EPA policies, guidance, and determinations through the Region 7 NSR database and/or hard copies where appropriate and will collaborate with MassDEP as necessary regarding interpretations of EPA policies, guidance and determinations. Where no current EPA policy or guidance clearly covers a specific situation, MassDEP shall consult with the EPA, Region 1, Office of Ecosystem Protection, Air Planning Branch, Air Permits, Toxics and Indoor Air Unit if it has questions on the interpretation of the EPA regulations.
2. The requirement to identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of federal programs, policies, and activities on minority and low-income populations, as set forth in *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, Exec. Order 12,898, 59 Fed. Reg. 7,629 (Feb. 16, 1994).

F. MassDEP will at no time grant a waiver to the requirements of 40 CFR 52.21 or to the requirements of an issued PSD permit.

Major new sources and major modifications to existing major sources are required to apply BACT pursuant to the PSD regulations at 40 C.F.R. § 52.21(j)(2) and (3). BACT is defined 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... for control of such pollutant." 40 C.F.R. § 52.21(b)(12); Clean Air Act (CAA) §169(3). In addition, BACT can be no less stringent than any applicable NSPS or MACT standard. Id.

Massachusetts has its own definition of BACT for the purposes of implementing its Comprehensive Plan Approval program under 310 CMR 7.02. Under that program, a source may propose an emission control limitation in lieu of an emission-unit-specific top-down BACT analysis, including reliance upon action issued by the Department, also known as "Top Case BACT.". See 310 CMR 7.02(8)(a)2.a. Based upon Footprint Power's application, it appears that Footprint Power relied upon the MassDEP "Top Case BACT Guidelines for Combustion Sources" to establish several of its proposed BACT limits for the PSD permit. See Salem Harbor Redevelopment Project, Comprehensive Plan Approval Application, at 5-1, 5-3, 5-4, 5-5; See also MassDEP Draft PSD Permit Fact Sheet, at 9.

The BACT analysis required under 40 C.F.R. 52.21 does not allow for this type of BACT by proxy; instead, it has been held repeatedly to require a unit-specific, case-by-case analysis that establishes a BACT limit that is "tailor-made" for each source and each pollutant. See In re City of Palmdale (Palmdale Hybrid Power Project), PSD Appeal No. 11-07, EAB, 2012 WL 4320533 (E.P.A.) Sept. 17, 2012, citing In re Prairie State Generating Co., 13 E.A.D. 1, 12 (EAB 2006), aff'd sub. nom, Sierra Club v. U.S. EPA, 499 F.3d 653 (7th Cir. 2007); In re Three Mountain Power, LLC, 10 E.A.D. 39, 47 (EAB 2001); Knauf I, 8 E.A.D., at 128-29. Therefore, the applicant should be required to provide and MassDEP should conduct new BACT analyses for any and all of the pollutants for which the applicant relied upon MassDEP's Top Case BACT guidance to ensure that the requirements of the federal regulations are met, and MassDEP should include more detailed information consistent with the requirements of 40 C.F.R. 52.21 regarding its analysis and justification for the BACT emissions limits that were ultimately set.

The establishment of BACT emission limits in the draft PSD permit in a manner which is inconsistent with 40 C.F.R. 52.21 constitutes an error of law by it relying upon the less stringent Massachusetts BACT standard and the MassDEP BACT guidance rather than implementing the legal requirements for BACT analysis set forth at 40 C.F.R. 52.21 as required by the Delegation Agreement. As discussed more fully below, this results in a Draft PSD permit with BACT limits that are invalid as a matter of law because they were not properly developed in accordance with the Delegation Agreement, the requirements of 40 C.F.R. 52.21, and the requirements of the Clean Air Act, 42 U.S.C. §7479(3).

II. Proposed gas turbine emission limits: 2 ppm NOx, 2 ppm CO, 1 ppm VOC (no duct firing), 1.7 ppm VOC (duct firing), 2 ppm NH3

The draft PSD permit establishes a CO limit of 2.0 ppmvd @ 15% O2 without conducting the proper BACT analysis, as described above. See Draft PSD Permit at Table 2, at 5. The draft PSD permit also establishes a VOC limit of 1.0 ppmvd @ 15% O2 without duct firing and 1.7 ppmvd @ 15% O2 with duct firing without conducting the proper BACT analysis as described above. See Draft PSD Permit at Table 2, at 6.

MassDEP clearly relied upon the Massachusetts Top Case BACT Guidelines in establishing the CO limit rather than implementing the federally required case-by-case BACT analysis. See MassDEP Draft PSD Fact Sheet at 12 ("Footprint proposes that the SHR Project will achieve CO emissions of 2.0 ppmvdc, which matches the top level of control for CO emissions as specified in the June 2011 MassDEP Top Case BACT Guidelines for combustion turbine combined cycle units firing natural gas."). Although the Fact Sheet also references two other recent projects, it does not indicate that a full BACT analysis was conducted. Thus, the CO BACT limit is invalid as a matter of law because it was derived in reliance upon the less stringent Massachusetts standards rather than in accordance with the federal regulations and laws governing BACT analysis.

In addition, permit applications with lower CO and VOC limits are under review. See March 2013 Cove Point LNG export project air permit application, for example. The project includes two GE Frame 7EA gas turbines. The proposed Cove Point GE gas turbine CO limit is 1.5 ppm. The proposed gas turbine VOC limit is 0.7 ppm.

Table 1. Gas Turbine Emission Limits at Proposed Cove Point (MD) LNG Export Project.

Emissions Source	Pollutant	Control Technology	Emission Rate[1]
GE 7EA Turbines (2)	NO_x NO_2	Selective Catalytic Reduction (SCR)	2.5 ppmvd
	CO	Oxidation Catalyst	1.5 ppmvd
	VOC	Oxidation Catalyst	0.7 ppmvd

Reducing the gas turbine CO limit from 2.0 ppm to 1.5 ppm would reduce projected Footprint Power CO emissions by more than 20 tpy. Reducing the gas turbine VOC limit from either 1.0 ppm (no duct firing) or 1.7 ppm (duct firing) to 0.7 ppm, under either no duct firing or duct firing, would reduce projected Footprint Power VOC emissions by at least 8 tpy.

Footprint Power and MassDEP provide no explanation why the proposed VOC emission rate is increased during duct firing while the 2 ppm CO limit is not increased during duct firing. Both CO and VOC are "products of incomplete combustion," and would generally be expected to increase or decrease in tandem. No justification has been offered for increasing the VOC limit during duct firing while leaving the CO limit unchanged.

Further, Table 2, Footnote 2 explains that the emissions rates are based on burning natural gas in any one combustion turbine at a maximum natural gas firing rate of 2,449 MMBtu/hr, HHV, at 90 F ambient temperature, 14.7 psia ambient pressure, and 60% ambient relative humidity (combustion turbine and duct burner combined). Thus, the limits provided for the unit with and without duct firing don't appear to provide a clear indication of the differences for each limitation with and without duct firing. We request that this information be included in the final permit.

III. Gas turbine start-up and shutdown emissions

Both GE and Siemens market rapid response combined cycle gas turbine power plants. Footprint Power will utilize GE Frame 7FA gas turbines. The unfired heat input to the Siemens SGT6-5000F turbine, at 2,096 MMBtu/hr, is very similar to the 2,130 MMBtu/hr unfired heat input to the GE Frame 7FA to be used at Footprint Power.[1,2] The draft air permit allows up to 89 lb of NOx per startup event over a period of up to 45 minutes. The NOx emissions limit during normal operations is 18.1 lb/hr. Therefore NOx emissions during an hour that includes a startup would be:

89 lb + (0.25 hr/1 hr)(18.1 lb/hr) = 93.5 lb per startup hour.

[1] SCAQMD, El Segundo Power, LLC, Addendum to Determination of Compliance, February 29, 2008, p.1, attached as Exhibit 2.

[2] MassDEP, Footprint Power Salem Harbor Development LP Draft PSD Permit Fact Sheet, Table 2, footnote, p. 7.

In contrast, the Siemens rapid response combined cycle power plant emits up to 24 lb of NOx over an uncontrolled 12-minute startup. The remaining 48 minutes of the startup hour would be at the controlled normal operations NOx emission rate of 15.44 lb/hr per turbine. Therefore, according the SCAQMD, based on its review of the Siemens fast response turbine startup NOx emission rate, the maximum NOx emissions during a startup hour would be:

24 lb + (0.80hr)(15.44 lb/hr) = 36.4 lb/hr.

The draft PSD permit indicates that up to 206 startups will occur each year on each combustion turbine.[3] Therefore 11.8 tons per year of additional startup NOx emissions would be avoided by either (1) use of the Siemens rapid response turbine or (2) reducing the NOx startup limit for the GE turbine selected by Footprint Power to an equivalent level.

2 turbines × (206 startup/hr per turbine/yr) × [(93.5 lb/hr – 36.4 lb/hr)/(2,000 lb/ton)] = 11.8 tpy

Moreover, although the MassDEP Draft Permit Fact Sheet indicates that the proposed startup and shutdown emissions limits represent BACT, it provides no basis for this conclusion. Again, MassDEP has failed to meet the requirements established by the Delegation Agreement, the federal regulations and the Clean Air Act regarding BACT analysis. Therefore, the MassDEP committed an error of law and the current BACT limits for startup and shutdown are invalid.

IV. Auxiliary boiler emission limits: 9 ppm NOx, 47 ppm CO, 11.8 ppm VOC

The auxiliary boiler is permitted to operate 6,570 hours/year. The auxiliary boiler will be permitted to operate on a base load, round-the-clock schedule. Yet the proposed emission limits are high and represent what would be expected for back-up combustion equipment. Footprint Power erroneously cites to the June 2011 MassDEP BACT guideline document as the basis for the auxiliary boiler limits. As noted above, use of the MassDEP guidance is contrary to the Delegation Agreement, the federal regulations, and the Clean Air Act. Therefore, the BACT emissions limit established for the auxiliary boilers was based upon an error of law and is invalid.

In addition, the one BACT example used in the BACT guideline document is for a boiler greater than 50 MMBtu/hr heat input. Here is the relevant excerpt from the BACT guideline document (p. 5):

Case Study: *In the recent past, boiler manufacturers have developed "ultra-low NOx burners" (ULNBs) which can achieve an oxides of nitrogen emission rate of 9 parts per million (ppm4). Before the advent of ULNBs, BACT for NOx for boilers with capacity above approximately 50 million British thermal units per hour was achieved by the use of Selective Catalytic Reduction (SCR) to reduce NOx emissions to 5 ppm, accompanied by a 5 ppm ammonia (NH_3) slip. When analyzing the incremental cost of using SCR to reduce the 9 ppm NOx emission rate attained by ULNB to reach a 5 ppm NOx emission limit, it became readily apparent that requiring SCR with added NH_3 emissions would be economically infeasible, on a dollar-per-ton-of-pollutant-removed basis. Therefore, NOx BACT for this category of emission units is now 9 ppm, with no NH_3 emissions.*

[3] MassDEP Fact Sheet, Table 2, footnote 1, p. 7.

What the MassDEP provides in the BACT guideline document is a historical example, not a rigorous 2013 top-down BACT analysis for the Footprint Power auxiliary boiler. The 2011 example presumes that the best performance possible for an SCR on a boiler greater than 50 MMBtu/hr is 5 ppm NOx and 5 ppm ammonia slip. In contrast, the two gas turbines at Footprint Power have proposed NOx and ammonia limits of 2 ppm. There is no dispute that 2 ppm NOx and 2 ppm ammonia slip is achievable when located in the waste-heat boiler of a combined cycle unit. If SCR is available with 2 ppm NOx and 2 ppm ammonia slip limits for the auxiliary boiler, SCR would be BACT for the Footprint Power auxiliary boiler and consistent with the 2011 MassDEP BACT guideline document. Nonetheless, the MassDEP is still obligated by the Delegation Agreement and the federal regulations to conduct a case-by-case BACT analysis rather than simply relying upon its less stringent guidance document.

The CO and VOC limits proposed in the draft air permit for the auxiliary boiler are high at 47 ppm and 11.8 ppm respectively. The draft air permit does not indicate that any case-by-case BACT analysis, as required by the Delegation Agreement and federal regulations, was conducted, nor does it even attempt to rely on the MassDEP BACT guideline document example to justify these high limits. Nor does the draft air permit acknowledge that the reason the proposed ultra-low burner can meet a 9 ppm NOx limit is by reducing the excess air to the burner to a minimum, which has the side effect of increasing products of incomplete combustion, CO and VOC, substantially. An oxidation catalyst on the auxiliary boiler would solve this CO and VOC emissions problem. Nor does the permit adequately explain the analysis for the NOx and VOC limits.

As a result, the current BACT limit for CO for the auxiliary boiler is based upon an error of law and is invalid.

V. Other Issues

Particulate Matter

Currently the permit establishes parametric monitoring as the primary method for ensuring compliance with the PM/PM10/PM2.5. Footprint should be required to install PM CEMS which are commercially available and have been installed on at least one electric generating unit operating in the Commonwealth (Mt. Tom Station) and are being required for two other electric generating units in the Commonwealth (Brayton Point and Palmer Renewable Energy). Particulate matter is one of the most deadly pollutants emitted from power plants, and should be monitored continuously to ensure compliance. The permit should also distinguish between filterable and condensable limits for PM.

With respect to the PM limits themselves, it appears that the BACT analysis required by the Delegation Agreement, the federal regulations and the Clean Air Act, as referenced above, was not implemented. MassDEP appears to have relied upon the top case BACT Guidance to establish that a rate of 0.0067 lbs/MMBtu and 0.0071 lbs/MMBtu would constitute BACT. See MassDEP Draft PSD Fact Sheet at 12-13. However, the most recent PSD permit issued by the EPA in Massachusetts determined that BACT was 0.004 lbs/MMBtu. Id. MassDEP failed to provide sufficient information for its conclusion that the PSD permit issued by Region 1 EPA for the Pioneer Valley Energy Center Project which included an emissions limit of 0.004 lbs/MMBtu would not be achievable and should not represent BACT for this facility. See MassDEP Draft PSD Permit Fact Sheet at 13. Rather than relying upon the MassDEP guidance and the performance of a facility that was constructed years ago, the MassDEP should have required a case-by-case, unit specific BACT analysis for PM as required by the federal regulations, the Delegation Agreement and the Clean Air Act. Failure to do so constitutes an error of law which renders the BACT limits for PM invalid.

Sulfur Content of Fuel

The permit establishes a limit of 0.5 grains/100scf of natural gas for Units 1-3, but the permit does not appear to provide any particular method to ensure continuous monitoring, reporting and compliance with this limit.

NO_2

We recently received additional information regarding the air dispersion modeling conducted to support the analysis of the potential impacts of the facility on ambient air quality. There appears to have been a significant change to the analysis with respect to NO_2. In one of the earlier scenarios, the cumulative impact of the facility along with the interactive sources appears to reach the 1-hour NAAQS for NO_2, 188 $\mu g/m^3$. See June 2013 revision with modeling for cumulative impacts at Table 6-11 shows that NO_2 reaches 188 which is the NAAQS for NO_2. They also appear to have changed the tons per year from 150 to 148.8.

However, the final Table 2 of the Proposed Plan Approval shows a maximum impact of 166. See Proposed Plan Approval at 14. MassDEP should require the applicant to explain the basis for the revisions to the analysis and expected potential to emit that changed the final analysis of the cumulative impacts of the facility.

Greenhouse Gas BACT

The draft/proposed permits establish a BACT limit for greenhouse gas emissions, however, it is unclear whether the project will achieve the same levels of efficiency and the heat rate limits of recently permitted projects. MassDEP should review the greenhouse gas emissions limits set for the Newark Energy Center in New Jersey as well as the other facilities referenced in a recent letter from Steven Riva, EPA Region 2 to the NJ DEP. See Letter from Steven Riva, Chief, Permitting Section, Air Programs Branch to Francis Steitz, Acting Asst Director, NJ DEP, Re: Newark Energy Center Project, Comments on PSD and NSR Preconstruction Permit Application (April 17, 2012). In that letter, Mr. Riva explained that:

> To minimize the GHG emissions, Newark Energy Center proposes as BACT to operate the turbines in combined-cycle mode at a heat rate limit of 6,005 Btu/kW-hr to achieve the thermal efficiency of 58.4% (LHV) with no duct firing. In comparison, the Russell Energy Project in California proposed to achieve a 56.4% efficiency and the Cricket Valley Project in New York proposed to achieve 57.4% efficiency.

Although the permit establishes a lb/MWh limit and higher heating value limits, it should also translate these limits into a thermal efficiency a requirement.

The permit references additional greenhouse gas emissions from nitrous oxide and methane, but it does not appear to account for the methane and nitrous oxide emissions in determining compliance with the emission limit for total GHGs. The emission factors from Table C-2 of 40 C.F.R. part 98 and global warming potentials from Table A-1 of 40 C.F.R. part 98 should be used, along with the measured heat input to the combustion turbines.

<u>Alternative Site Evaluation</u>

Based upon the proposed/draft permits, MassDEP appears to have taken the project proponent's claims at face value regarding the alternative site analysis required under the Nonattainment New Source Review program. For example, MassDEP accepted the CRA analysis of the potential greenhouse gas emissions impacts of the facility without examining the underlying assumptions and recognizing that some of these assumptions (such as the heavy and arbitrary discount to the mandated energy savings goals from the Department of Public Utilities approved energy efficiency programs), an incomplete analysis of proposed transmission upgrades, a failure to include the Commonwealth's goals for installation of wind and solar capacity, and a flawed analysis of expected retirements of generating facilities in the region. <u>See</u> Proposed Plan Approval at 10. MassDEP should have conducted a more thorough analysis of the claims and studies provided by the project proponent rather than simply accepting these analyses as accurate and complete.

<u>Air Modeling and Dispersion Analysis</u>

We have not had an opportunity to complete our analysis of the recently provided air dispersion modeling and underlying assumptions, but at this stage we would request that the MassDEP provide a more detailed explanation regarding why preconstruction monitoring as provided for through the PSD regulations was not undertaken, why the monitors from Lynn and Harrison Avenue were considered appropriate for estimating the impacts of this facility, and, as noted above, what changes in the emissions inventory caused the reduction of the maximum predicted 1-hour NO_2 concentration to be reduced from 188 ($\mu g/m^3$) (the NAAQS) to 166 ($\mu g/m^3$). Given how little difference there is between the predicted 1-hour concentration and the standard, small changes in emissions can be very important to a compliance demonstration.

Also, the modeling analysis is defective due to its use of Logan Airport meterological data. The specific geographic, wind, and other feature differences as between Logan airport and the site that render it inappropriate for use in the modeling. In addition, it was improper to choose the rural *determination rather than the urban given the densely populated areas surrounding the site.* We are particularly concerned about the statements in both the Air Dispersion Modeling Protocol of August 2012 and the Proposed Plan Approval that, on the basis of land use within a 3 km radius around the site "rural dispersion coefficients were used in the dispersion modeling." We understand that the dispersion coefficients for use in AERMOD are not to be determined by a rural/urban designation but are to be determined by the values of the surface roughness length, surface albedo and surface Bowen Ratio as calculated by the application of AERSURFACE to the area within a 1 km radius of the anemometer used for wind speeds and directions in AERMOD .

Recordkeeping/Reporting Requirements

Table 10 of the Proposed Plan Approval requires the Permittee to maintain monthly records to demonstrate compliance with the facility-wide emission limits specified in Table 7. We recommend requiring that those monthly records be submitted to MassDEP on a quarterly basis in addition to the semi-annual reporting requirement contained in Table 11.

GWSA Compliance

As we stated at the public hearing, there is no evidence in the record to support MassDEP's proposed Section 61 finding that this project is consistent with the GWSA requirements. The only analysis that MassDEP apparently relies upon to reach its conclusion was the analysis presented by Charles River Associates, which only covered the period through 2025, and was riddled with flawed assumptions as referenced above. There is no indication that the applicant presented any information regarding the greenhouse gas emissions impacts from the project through 2050. In addition, MassDEP has a special obligation to ensure compliance with the requirements of the GWSA because it was required to promulgate regulations establishing declining annual aggregate emissions limits for sources and categories of sources by no later than January 1, 2012 to go into effect by January 1, 2013 through December 31, 2020. G.L. c. 21N, § 3d; St. 2008, c. 298, § 16. MassDEP's failure to promulgate these rules does not excuse sources and categories of sources of greenhouse gas emissions from being required to meet the mandates of the GWSA.

Process and Venue for Appeals

The Draft Prevention of Significant Deterioration Fact Sheet (the "Fact Sheet") misstates the law regarding appeals of air permits. MassDEP's procedures and activities in reviewing and rendering a determination on an application for an air permit are governed, in the first instance, by its enabling authority as enacted by the General Court of the Commonwealth of Massachusetts. A recent MassDEP Commissioner's decision clarified that the filing of an application for an air quality permit which seeks "the Department's determination of its right to construct and operate a facility" commences an "adjudicatory proceeding" as the term is defined in Massachussetts G.L. c. 30A, §1 for purposes of appealing any such decision. See, In the Matter of Palmer Renewable Energy, LLC, Final Decision dated September 11, 2012; OADR Docket No. 2011-021 & -022. As codified in G.L. c. 111, § 142B and c. 30A, § 14 appeals of agency determinations, as would be rendered by MassDEP in the instant proceeding, "shall be instituted in the Superior Court…."

The Fact Sheet (at page 34), however, provides that interested parties seeking to appeal MassDEP's final permitting decision "may submit a petition for review of the Permit to MassDEP's Wilmington Office, which is consistent with appeal requirements specified in 40 C.F.R. 124.19." Under 40 C.F.R. 124.19, the venue for appeals of PSD permitting decisions is the USEPA Environmental Appeals Board (EAB). Even a cursory review of the process under 40 CFR §124.19 makes it clear that appeals to the EAB are not and would not be consistent with the foregoing codified Massachusetts law governing appeals of air permitting decisions rendered by MassDEP.

The procedures and venue for appeals of MassDEP air permitting decisions, as provided in the Fact Sheet, are ultra vires, and any such permitting action by MassDEP based on the process and venue provided in the Fact Sheet would be inconsistent with Massachusetts law. In its Final Permit Decision, MassDEP needs to clarify the venue and procedure for appeals of its final PSD Permit Decision in a manner which conforms to its codified enabling authority.

Respectfully submitted,

CONSERVATION LAW FOUNDATION

By its attorney,

Shanna Cleveland

Shanna Cleveland

and

Elizabeth Michaud
Michel Beheshti
Jeff Brooks
Andrea Celestine
William Dearstyne
Linda Haley
Douglas Haley
HealthLink
Clean Water Action
Jane Bright
Martha Dansdill
Rosalind Nadeau
Sue Kirby, 350ma.org
Dorian Williams, Better Futures Project
Jody Howard
Marlene Faust

EXHIBIT 1

Agreement for Delegation of the Federal Prevention of Significant Deterioration (PSD) Program by the United States Environmental Protection Agency, Region 1 to the Massachusetts Department of Environmental Protection

This agreement sets forth the terms and conditions according to which the Commonwealth of Massachusetts Department of Environmental Protection (MassDEP) agrees to implement and enforce the federal PSD regulations as found in 40 CFR 52.21, the Code of Federal Regulations (CFR), 7-1-10 Edition. The regulations also include the following amendments:

1. June 3, 2010 effective August 2, 2010 [amended language provided for reference in 7-1-10 CFR]; and
2. October 20, 2010 with respect to $PM_{2.5}$ Increments, Significant Impact Levels, and Significant Monitoring Concentration, 75 FR 64864, effective December 20, 2010.

As noted in the 7-1-10 CFR,

1. the provisions related to inclusion of fugitive emissions, 40 CFR 52.21(a)(2)(iv)(b), (b)(2)(v), (b)(3)(iii)(b), (b)(3)(iii)(c), (b)(20), (b)(41)(ii)(b), (b)(41)(ii)(d), (b)(48)(i)(a), (b)(48)(ii)(a), (b)(48)(iii), (b)(48)(iv), (r)(6)(iii), (r)(6)(iv), (aa)(4)(i)(d), were stayed effective April 1, 2010, until October 3, 2011 by federal court order;
2. the provisions related to routine maintenance, repair and replacement, 40 CFR 52.21 (b)(2)(iii)(a), (b)(55)-(58), and (cc), were stayed indefinitely December 24, 2003 by federal court order; and
3. the provision related to inclusion of fugitive emissions at 40 CFR 52.21(i)(1)(vii) is effective until October 3, 2011.

I. Introduction

Authority and/or Commitments for implementation of 40 CFR 52.21, as in effect on August 2, 2010. Massachusetts has demonstrated it has adequate legal authority to implement and enforce all requirements as they relate to PSD. This legal authority is contained in Massachusetts's enabling legislation and in regulatory provisions. EPA has determined that this legal authority is sufficient to allow Massachusetts to issue permits that assure compliance with all PSD requirements.

II. Legal Authority

A. Pursuant to 40 CFR 52.21(u), EPA may delegate to a State or local agency full or partial responsibility for conducting new source review pursuant to the federal PSD regulations found in 40 CFR 52.21.

B. MassDEP and EPA agree that requirements in PSD permits issued under the Commonwealth's authority are federally enforceable requirements.

III. Scope of Delegation

A. Pursuant to 40 CFR 52.21(u), EPA hereby delegates to MassDEP full responsibility for implementing and enforcing the federal PSD regulations for all sources located in the Commonwealth of Massachusetts, subject to the terms and conditions of this Delegation Agreement.

B. MassDEP's delegation to implement and enforce the federal PSD regulations under this Delegation Agreement does not extend to sources or activities located in Indian Country, as defined in 18 U.S.C. § 1151. MassDEP also recognizes that for certain sources and PSD permitting affecting Indian tribes EPA may need to consult the affected Indian tribes.

C. MassDEP's delegation to implement and enforce the federal PSD regulations under this Delegation Agreement does not extend to sources or activities located on the Outer Continental Shelf, or to deepwater ports as defined by 33 U.S.C. chapter 29.

D. The EPA Administrator has delegated to Region 1's Regional Administrator the authority to delegate authority to State or local agencies to implement preconstruction review for prevention of significant deterioration or new or modified major stationary sources under the regulation in 40 CFR 52.21. The State or local agency that receives delegation from EPA Region 1 does not have the authority under the federal Clean Air Act to further delegate the federal PSD regulations.

IV. Requirements

A. The responsibility for implementing the federal PSD program for all regulated sources as provided by this Delegation Agreement rests with MassDEP's Bureau of Waste Prevention. EPA is relying on the technical and programmatic expertise of MassDEP's Bureau of Waste Prevention in the implementation of this Delegation Agreement on MassDEP's behalf. The Director of the Bureau of Waste Prevention's Business Compliance Division will serve as the point of contact for this Delegation Agreement and the Air Permit Section Chief in the MassDEP regional office with jurisdiction will be the point of contact for PSD applicability determinations and permit decisions for particular facilities in the respective regions. If MassDEP reorganizes such that the Bureau of Waste Prevention is unable to implement the federal PSD program, then MassDEP must immediately notify EPA of this reorganization and in such a case, this Delegation Agreement must be amended.

B. MassDEP will ensure there are adequate resources and trained personnel within the Bureau of Waste Prevention to implement an effective PSD permit program. As requested, EPA will provide technical assistance related to the federal PSD requirements, including without limitation, PSD applicability determinations, Best Available Control Technology (BACT) determinations, air quality monitoring network design, modeling procedures and other issues such as federal Environmental Justice policies.

C. Where the rules or policies of MassDEP are more stringent than the federal PSD program, MassDEP may elect to include such requirements in the PSD permit along with the EPA requirements, but will clearly indicate within the PSD permit itself which permit conditions do not derive from federal PSD requirements.

D. If a State (or local) regulation and a federal regulation apply to the same source, then MassDEP will apply the federal regulation if it is more stringent than the State (or local) regulation. Nothing in this Delegation Agreement shall be construed as precluding or limiting application or enforcement of either the State (or local) regulation or the federal regulation, regardless of whether one is more stringent than the other, subject to the requirements of section 116 of the Clean Air Act.

E. MassDEP will follow EPA policy, guidance, and determinations as applicable for implementing the federal PSD program, whether issued before or after the execution of this Delegation Agreement, including:

1. PSD policy, guidance, and determinations issued by EPA. EPA will provide MassDEP with copies of EPA policies, guidance, and determinations through the Region 7 NSR database and/or hard copies where appropriate and will collaborate with MassDEP as necessary regarding interpretations of EPA policies, guidance and determinations. Where no current EPA policy or guidance clearly covers a specific situation, MassDEP shall consult with the EPA, Region 1, Office of Ecosystem Protection, Air Planning Branch, Air Permits, Toxics and Indoor Air Unit if it has questions on the interpretation of the EPA regulations.
2. The requirement to identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of federal programs, policies, and activities on minority and low-income populations, as set forth in *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, Exec. Order 12,898, 59 Fed. Reg. 7,629 (Feb. 16, 1994).

F. MassDEP will at no time grant a waiver to the requirements of 40 CFR 52.21 or to the requirements of an issued PSD permit.

G. MassDEP shall consult with the appropriate State and local agencies primarily responsible for managing land use as provided in 40 CFR 52.21(u)(2)(i) prior to making any preliminary or final determination under this Delegation Agreement.

H. With respect to the Endangered Species Act (ESA), the obligations of EPA, MassDEP, and permit applicants will be set forth in a separate designation letter issued under 50 C.F.R. § 402.08 ("ESA Letter"). With respect to Section 106 of the National Historic Preservation Act (NHPA), the respective obligations of EPA, MassDEP, and permit applicants will be set forth in a separate designation letter issued under 36 C.F.R. § 800.2(c)(4) ("NHPA Letter"). With respect to the federal trust responsibility to federally-recognized Indian tribes and implementation of EPA's Indian tribal policies, EPA alone will have responsibility for tribal consultation. Until such time as the designations described above are completed, EPA shall be responsible for making the respective determinations. In furtherance of EPA's determinations, MassDEP shall:

1. Require PSD permit applicants to submit, as part of their PSD permit applications, any information necessary to determine whether issuance of such permits: (1) may affect federally-listed threatened or endangered species or the designated critical habitat of such species; and, if so, whether permit issuance is likely to adversely affect such species/designated critical habitat and/or jeopardize the continued existence of such species or result in the destruction or adverse modification of designated critical habitat, (2) has the potential to cause effects on historic properties; and, if so, whether such effects may be adverse, and/or (3) has the potential to affect Indian tribes.

2. Require the applicant to (1) notify, within 5 working days after submitting a PSD permit application, the following agencies, and (2) provide a copy of the permit application if requested by one of the agencies:

   A. U.S. Fish and Wildlife Service (FWS);
   B. National Marine Fisheries Service (NMFS);
   C. The Massachusetts State Historic Preservation Officer (SHPO);
   D. The Tribal Historic Preservation Officer (THPO) and, via separate copy, the tribal environmental director, for the Mashpee Wampanoag Tribe and for the Wampanoag Tribe of Gay Head (Aquinnah);
   E. When required by the NHPA Letter: the SHPO for a bordering state, and/or the THPO for a federally-recognized Indian tribe in a bordering state.

3. If EPA informs MassDEP that EPA requires more time to consult with an Indian tribe before issuance of a draft PSD permit, refrain from issuing the draft PSD permit until EPA informs MassDEP that it may do so.

4. In all cases, MassDEP will refrain from issuing any final PSD permit until EPA has notified MassDEP that EPA has satisfied its NHPA, ESA, and tribal consultation responsibilities with respect to that permit.

5. On request by EPA, MassDEP will provide copies of any documents prepared or received by MassDEP related to ESA and/or NHPA compliance.

I. EPA will review draft PSD permits that MassDEP submits for public comment. If EPA informs MassDEP that EPA does not concur with MassDEP's BACT determinations and/or modeling analyses performed to determine increment consumption and compliance with National Ambient Air Quality Standards, then MassDEP will not issue a final PSD permit until EPA and MassDEP have reached agreement on the BACT determinations and/or modeling analyses. EPA and MassDEP shall collaborate and make every effort to resolve all disagreements in a mutually satisfactory way. If EPA determines that EPA and MassDEP have reached an impasse and further discussions are not likely to yield such an agreement, EPA will notify MassDEP of its determination in writing and then EPA may, at its discretion, issue a partial *Notice of Revocation* under Section IX of this Delegation Agreement with respect to that particular PSD permit, take exclusive permitting authority for that PSD permit, and, as appropriate, issue a final PSD permit, deny the PSD permit application, or take other appropriate action under 40 CFR part 124.

J. The primary responsibility for the administration and enforcement of the PSD permits issued by EPA to Dominion Energy Brayton Point, LLC, Somerset, MA, April 2, 2009 and October 7, 2009, Northeast Energy Associates, Bellingham, MA, December 23, 2008, University of Massachusetts (UMass), Amherst, MA, July 25, 2005 and October 29, 2008, Braintree Electric Light Department (BELD), Braintree, MA, April 4, 2008, General Electric Aviation (GE), Lynn, MA, March 13, 2008, and Fore River Station, N. Weymouth, MA, December 14, 2006, is delegated to MassDEP. MassDEP-issued modifications to these permits which meet the requirements of 40 CFR 52.21 and 40 CFR part 124 will be considered valid by EPA. Any permit modifications that MassDEP issues to these facilities shall be issued pursuant to this agreement.

K. EPA will retain responsibility for issuance and, if necessary, defense on appeal of the PSD permit to be issued to Pioneer Valley Energy Center (PVEC) in response to PVEC's November 2008 permit application. After that permit has taken final effect, any permit modifications to this facility that MassDEP issues shall be issued pursuant to this agreement, and any future MassDEP-issued modifications to the permit which meets the requirements of 40 CFR 52.21 and 40 CFR part 124 will be considered valid by EPA.

V. Permit Issuance, Modification, and Appeals

A. All permits issued by MassDEP under this Delegation Agreement shall follow the applicable procedures in 40 CFR 52.21 and 40 CFR part 124, as they may be amended from time to time. These provisions include, but are not limited to:

1. The requirements applicable to completeness determinations, as provided by § 124.3;
2. The requirements applicable to a draft permit, fact sheet, and draft permit administrative record, as provided by §§ 124.6, 124.8, and 124.9;
3. The requirements applicable to public notice, public comment, and public hearings, provided by §§ 124.10, 124.11, and 124.12;
4. The requirements applicable to a final permit, response to comments, and administrative record, provided by §§ 124.15, 124.17, and 124.18; and
5. The additional requirements applicable to sources potentially affecting Federal Class I areas, provided by § 124.42 and § 52.21(p), including the timeframes specified in § 52.21(p).

B. The provisions in 40 CFR 124.19 shall apply to all appeals to the EPA Environmental Appeals Board (EAB) on PSD permits issued by MassDEP under this Delegation Agreement, except with respect to permit conditions that do not derive from federal PSD requirements, for which applicable Massachusetts administrative procedures apply. If a PSD permit issued by MassDEP is appealed to the EAB, MassDEP has the primary responsibility for defending the permit before the EAB and the discretion to withdraw the permit under 40 CFR 124.19(d).

C. For purposes of implementing the Federal permit appeal provisions under this delegation, MassDEP will notify the applicant and each person who has submitted written comments or requested notice of the final permit decision of their right to appeal, and this notice is required to state that for federal PSD purposes and in accordance with 40 CFR 124.15 and 124.19:

1. Within 30 days after the final PSD permit decision has been issued under 40 CFR 124.15, any person who filed comments on the draft permit or participated in any public hearing may petition EPA's Environmental Appeals Board to review any condition of the permit decision.

2. The effective date of the permit is 30 days after service of notice to the applicant and commenters of the final decision to issue, modify, or revoke and reissue the permit, unless review is requested on the permit under 40 CFR 124.19 within the 30 day period.

3. If an appeal is made to the EAB, the effective date of the permit is suspended until the appeal is resolved.

D. Major modifications to existing PSD permits shall be processed in accordance with all of the substantive and procedural requirements applicable to new PSD permits. Non-major modifications to existing PSD permits shall be processed in accordance with all applicable PSD policy, guidance, and determinations issued by EPA. Until EPA develops specific procedural requirements for non-major modifications to existing PSD permits, non-major modifications shall be processed according to the procedural requirements of 40 CFR Part 124 applicable to new PSD permits.

E. In the event that EPA determines that a PSD permit does not comply with the requirements of 40 CFR Part 124 related to PSD permits and this Section V. of this Delegation Agreement, EPA shall notify MassDEP that such permit is invalid for federal PSD purposes.

F. MassDEP shall issue (or deny) a final PSD permit within one year of receipt of a complete PSD application, in accordance with Section 165(c) of the Clean Air Act.

G. If at any time the Energy Facilities Siting Board notifies MassDEP that it has received an application for a certificate pursuant to M.G.L. ch. 164, § 69K or § 69K1/2, which would, if granted, exempt the source from, or modify, the terms of any applicable PSD requirement, then MassDEP will immediately notify EPA so that EPA may exercise its concurrent administrative and enforcement authority.

VI. Enforcement

A. In all cases, EPA retains authority pursuant to sections 113 and 167 of the Clean Air Act with respect to sources that are subject to the federal PSD requirements, including federal PSD permits issued by MassDEP.

B. In delegated programs, the role of the delegated agency is that of primary enforcer or "front line" agency in program implementation. However, EPA will initiate an enforcement action, as appropriate, under the following circumstances:

1. At MassDEP's request;

2. If after consultation with MassDEP, EPA determines that MassDEP's enforcement action is inadequate, or that MassDEP is failing to carry out action in a timely or appropriate manner; and/or

3. As part of EPA's role established in an EPA-MassDEP collaborative planning process, which includes those situations where national, regional, or sector initiatives warrant an EPA lead.

VII. EPA and MassDEP Communications

A. MassDEP shall ensure that copies of the following documents are submitted to EPA, within the time frames indicated, for sources or activities subject to this Delegation Agreement:

Action	Submittal to EPA	Time Frame
Receipt of PSD permit application	Copy of application and cover letter	Within ten working days after receipt
Completeness determination or letter of deficiencies	Copy of letter to applicant	Within ten working days after signature
Transmittal to Federal Land Manager (FLM), FWS, NMFS, SHPO, and THPO of PSD permit application	Copy of letter	Within ten working days after signature
Receipt of comments from FLM, FWS, NMFS, SHPO, and THPO	Forward comment letter	Within ten working days of receipt
Draft PSD permit, public notice	Copy of fact sheet and any supporting technical information, draft PSD permit (including major or minor modifications), and public notice	No later than date of public notice under 40 CFR 124.10
Receipt of comments from public	Copy of public comment letter(s)	Within ten working days of the close of the public comment period
Final determination, PSD permit and transmittal letter	Copy of final PSD permit, response to comments, and transmittal letter	Within five working days after final signature on PSD permit
BACT determination submittal to RACT/BACT/ LAER Clearinghouse	Electronic submittal of required information	Within 30 working days of final signature on PSD permit
Petition for review before Environmental Appeals Board (if any)	Copy of petition	Within five working days after receipt

B. MassDEP and EPA will communicate sufficiently to guarantee that each is fully informed and current regarding interpretation of federal PSD regulations (including any unique questions about PSD applicability). MassDEP will make available to EPA, upon request, any records or reports relating to PSD permitting or compliance with PSD requirements that are provided to or otherwise obtained by MassDEP and are not identified in the Table in Section VII.A. above. If MassDEP determines, in accordance with Massachusetts public records requirements, that it cannot or will not provide a record or report to EPA, then EPA and MassDEP will consult on whether such document is essential to EPA's review and whether the information could be provided by alternate means. If EPA concludes that it requires the document and MassDEP concludes that it cannot provide the document, then EPA may proceed according to Sections VI.B.2 and/or IX.B, as appropriate, of this agreement.

C. MassDEP will ensure that all relevant source information, notifications and reports are entered into the EPA AIRS/AFS national database system in order to meet its recordkeeping and reporting requirements. In addition to the National Minimum Data Requirements (MDRs) (attached), MassDEP shall enter the following information or activities:

1. The Air Program Code for PSD
2. The date the PSD permit is issued or modified
3. The final effective date of the PSD permit (or modified permit)
4. The date that the new source or modification begins construction; and
5. The date that the new source or modification begins operation.

D. Correspondence from EPA to MassDEP will be sent to:

Director, Business Compliance Division
Bureau of Waste Prevention
Department of Environmental Protection
One Winter Street
Boston, MA 02108 and,

Air Permit Section Chief, Bureau of Waste Prevention, for the MassDEP Regional Office where the PSD project is located.

Correspondence from MassDEP to EPA will be sent to:

Director, Office of Ecosystem Protection
EPA New England, Region 1
5 Post Office Square
Mail Code OEP06-5
Boston, MA 02109-3912

VIII. Future EPA Regulation Revisions

A. MassDEP's delegation to implement and enforce the federal PSD regulations applies to 40 CFR 52.21 and 40 CFR part 124 as they may be amended from time to time, unless MassDEP specifically informs EPA otherwise as provided in Section VIII.C below.

B. If any additional pollutants become "regulated NSR pollutant(s)" within the meaning of 40 CFR 52.21(b)(50) after the date of this Delegation Agreement, MassDEP will implement the federal PSD regulations with respect to such pollutant(s).

C. If, as a result of regulatory revisions after the date of this Delegation Agreement, MassDEP becomes unwilling or unable to implement or enforce the federal PSD regulations as provided in this Delegation Agreement with respect to a source or activity subject to the federal PSD regulations, then MassDEP will so inform EPA, and propose either that MassDEP continue to implement the PSD program only for projects that do not trigger the revised regulatory provisions, or that this Delegation Agreement be otherwise amended or revoked. Unless MassDEP and EPA agree otherwise, the provisions of Section IX.B-D will apply.

IX. Administrative

A. This Delegation Agreement supersedes EPA's rescission of delegation dated March 3, 2003.

B. If, after consultation with MassDEP, EPA makes any of the following determinations, this delegation may be revoked in whole or in part. Any such revocation shall be effective as of the date specified in a *Notice of Revocation*.

1. MassDEP's legal authority, rules and regulations, and/or procedures for implementing or enforcing the federal PSD requirements as provided in this Delegation Agreement are inadequate;

2. MassDEP is not adequately implementing or enforcing the federal PSD program; or

3. MassDEP has not implemented the requirements or guidance with respect to a specific permit in accordance with the terms and conditions of this delegation, the requirements of 40 CFR 52.21, 40 CFR part 124, or the Clean Air Act.

C. In the event that MassDEP is unwilling or unable to implement or enforce the federal PSD regulations as provided in this Delegation Agreement with respect to a source or activity subject to the federal PSD regulations, MassDEP will immediately notify the Director of the Office of Ecosystem Protection and the Chief of the Air Planning Branch. Failure to notify the Director of the Office of Ecosystem Protection and the Chief of the Air Planning Branch does not preclude EPA from exercising its enforcement authority.

D. In the event that EPA or MassDEP regulations or policies change, EPA and MassDEP will consult to determine whether this delegation should be amended to ensure the continued implementation of EPA's PSD regulations, or, alternatively, revoked.

E. Either EPA or MassDEP may terminate this agreement upon providing the other party 30 days prior notice. Such notice shall include the reasons for such termination.

X. Signatures

On behalf of the MassDEP, I accept full delegation of the Federal Prevention of Significant Deterioration program, 40 CFR 52.21, program pursuant to the terms and conditions of this delegation agreement and the requirements of the Clean Air Act.

Date: 4/4/11

Kenneth L. Kimmell
Commissioner
Department of Environmental Protection

On behalf of the Environmental Protection Agency, I grant full delegation of the federal PSD program, 40 CFR 52.21, to MassDEP pursuant to the terms and conditions of this delegation agreement and the requirements of the Clean Air Act.

Date: 4/11/11

H. Curtis Spalding
Regional Administrator
Environmental Protection Agency
Region 1

EXHIBIT 2

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT ENGINEERING AND COMPLIANCE DIVISION ENGINEERING ANALYSIS / EVALUATION	PAGES 43	PAGE 1
	APPLICATION NO. 470652 (Master File)	DATE 2-29-2008
	PROCESSED BY: Ken Coats	REVIEWED BY:

EL SEGUNDO POWER, LLC
ADDENDUM TO DETERMINATION OF COMPLIANCE

COMPANY NAME AND ADDRESS

El Segundo Power, LLC
301 Vista Del Mar
El Segundo, CA 90245

EQUIPMENT LOCATION

301 Vista Del Mar
El Segundo, CA 90245

Contact: Mr. Steve Odabashian (310) 615-6331
AQMD Facility ID: 115663

EQUIPMENT DESCRIPTION

Section H of the Facility Permit

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 2: GAS TURBINE, POWER GENERATION					
GAS TURBINE, UNIT NO. 8, NATURAL GAS, SIEMENS MODEL SGT6-5000F, RAPID-RESPONSE COMBINED CYCLE, 2,096 MMBTU/HR AT 78 DEGREES F, WITH DRY LOW-NOX COMBUSTORS WITH A/N 470652 GENERATOR, HEAT RECOVERY STEAM, UNFIRED STEAM TURBINE, 67.7 MW GENERATOR, 219 MW	D67	C75	NOX: MAJOR SOURCE	**CO:** 2.0 PPMV NATURAL GAS (4) [Rule 1703(a)(2)-PSD-BACT]; **CO:** 2000 PPMV (5) [Rule 407] **NOX:** 15 PPMV NATURAL GAS (8) [40CFR60 Subpart KKKK] **NOX:** 16.55 LB/MMCF NATURAL GAS (1) [Rule 2012] **NOX:** 8.66 LB/MMCF NATURAL GAS (1A) [Rule 2012] **NOX:** 2.0 PPMV NATURAL GAS (4) [Rule 2005-BACT, Rule 1703(a)(2)-PSD-BACT]; **NOX:** 0.080 lb/MW-hr NATURAL GAS (5) [Rule 1309.1] **VOC:** 2.0 PPMV (4) [Rule 1303(a)(1)-BACT] **PM10**: 0.01 GRAIN/DSCF (5) [Rule 475]; **PM10**: 0.1 GRAIN/DSCF (5A) [Rule 409]; **PM10**: 11 LB/HR (5B) [Rule 475]; **PM10:** 0.060 lb/MW-hr NATURAL GAS (5C) [Rule 1309.1] **SOX**: 0.06 LB/MMBTU (8) [40 CFR60 Subpart KKKK] **SO2**: (9) 40CFR72-Acid Rain Provisions	A63.2, A99.7, A99.8, A99.9, A99.10, A99.11, A195.8, 195.9, A195.10, A327.1, A433.1, B61.2, C1.6, D12.10, D29.7, D29.8, D29.9, D29.10; D82.4, D82.5, E193.2, E193.3, I296.2, K40.4, K67.5

EQUIPMENT DESCRIPTION (continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 2: INTERNAL COMBUSTION					
System 2: GAS TURBINE, POWER GENERATION					
CO OXIDATION CATALYST, UNIT NO. 8, BASF, 290 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 470653	C75	D67 C76			
SELECTIVE CATALYTIC REDUCTION, UNIT NO. 8, CORMETECH MODEL CM 21HT, WITH 2,050 CUBIC FEET OF TOTAL CATALYST VOLUME, LENGTH: 24 FT 3 IN; WIDTH: 25 FT 0 IN; HEIGHT: 70 FT 0 IN; WITH NH3 INJECTION GRID A/N: 470653	C76	C75 S78		**NH3:** 5.0 PPMV (4) [Rule 1303(a)(1)-BACT]	A195.11 D12.11 D12.12 D12.13 E179.5 E179.6
STACK NO. 8, DIAMETER: 20 FT 11 IN, HEIGHT: 210 FT 0 IN A/N: 470652	S78	C76			
GAS TURBINE, UNIT NO. 9, NATURAL GAS, SIEMENS MODEL SGT6-5000F, RAPID-RESPONSE COMBINED CYCLE, 2,096 MMBTU/HR AT 78 DEGREES F, WITH DRY LOW-NOX COMBUSTORS WITH A/N 470656 GENERATOR, HEAT RECOVERY STEAM, UNFIRED STEAM TURBINE, 67.7 MW GENERATOR, 219 MW	D68	C79	NOX: MAJOR SOURCE	**CO:** 2.0 PPMV NATURAL GAS (4) [Rule 1703(a)(2)-PSD-BACT]; **CO:** 2000 PPMV (5) [Rule 407] **NOX:** 15 PPMV NATURAL GAS (8) [40CFR60 Subpart KKKK] **NOX:** 16.55 LB/MMCF NATURAL GAS (1) [Rule 2012] **NOX:** 8.66 LB/MMCF NATURAL GAS (1A) [Rule 2012] **NOX:** 2.0 PPMV NATURAL GAS (4) [Rule 2005-BACT, Rule 1703(a)(2)-PSD-BACT]; **NOX:** 0.080 lb/MW-hr NATURAL GAS (5) [Rule 1309.1] **VOC:** 2.0 PPMV (4) [Rule 1303(a)(1)-BACT] **PM10:** 0.01 GRAIN/DSCF (5) [Rule 475]; **PM10:** 0.1 GRAIN/DSCF (5A) [Rule 409]; **PM10:** 11 LB/HR (5B) [Rule 475]; **PM10:** 0.060 lb/MW-hr NATURAL GAS (5C) [Rule 1309.1] **SOX:** 0.06 LB/MMBTU (8) [40 CFR60 Subpart KKKK] **SO2:** (9) 40CFR72-Acid Rain Provisions	A63.2, A99.7, A99.8, A99.9, A99.10, A99.11, A195.8, 195.9, A195.10, A327.1, A433.1, B61.2, C1.6, D12.10, D29.7, D29.8, D29.9, D29.10; D82.4, D82.5, E193.2, E193.3, I296.2, K40.4, K67.5

EQUIPMENT DESCRIPTION (continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 2: INTERNAL COMBUSTION					
System 2: GAS TURBINE, POWER GENERATION					
CO OXIDATION CATALYST, UNIT NO. 9, BASF, 290 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 470654	C79	D68 C80			
SELECTIVE CATALYTIC REDUCTION, UNIT NO. 9, CORMETECH MODEL CM 21HT, WITH 2,050 CUBIC FEET OF TOTAL CATALYST VOLUME, LENGTH: 24 FT 3 IN; WIDTH: 25 FT 0 IN; HEIGHT: 70 FT 0 IN; WITH NH3 INJECTION GRID A/N: 470654	C80	C79 S82		**NH3:** 5.0 PPMV (4) [Rule 1303(a)(1)-BACT]	A195.11 D12.11 D12.12 D12.13 E179.5 E179.6
STACK NO. 9, DIAMETER: 20 FT 0 IN, HEIGHT: 210 FT 0 IN A/N: 470656	S82	C80			
Process 5: INORGANIC CHEMICAL STORAGE					
STORAGE TANK, UNDERGROUND, TK-001 , AQUEOUS AMMONIA, 29 PERCENT, CARBON STEEL,DOUBLE WALLED, WITH 3 TRANSFER PUMPS AND A PRV SET AT A MINIMUM OF 50 PSIG, 20,000 GALLONS, DIAMETER: 10 FT 2 IN; LENGTH: 37 FT 10 IN; WITH SCRUBBER, VENTURI, TWO STAGE WITH A/N: 379904	D30 C64				C157.1, E144.2

ORIGINAL DESIGN

The El Segundo Generating Station (ESGS) is located on a 32.8-acre site in El Segundo, CA. The facility is bordered on the west by Santa Monica Bay, on the east by Vista Del Mar, on the north by the Chevron Marine Terminal, and on the south by 45th Street in the City of Manhattan Beach. The ESGS has been operating as an electric generating station since May 1955. The facility was originally owned and operated as a public utility by the Southern California Edison (SCE) Company. In 1998, SCE sold the facility to El Segundo Power, LLC as part of deregulation. Since 1998 El Segundo Power, LLC has owned and operated the facility. As part of the El Segundo Power Redevelopment Project (ESPR) existing utility boiler units 1 & 2 are to be demolished and removed from service and replaced with two General Electric 7FA combined cycle combustion turbine generators (CTGs) each being equipped with a vertical flow heat recovery steam generator (HRSG) and two 600 MMBTU/hr duct burners.

Each CTG will be equipped with SCR/CO catalyst unit. Also included is an emergency fire pump rated at 265 BHP. On December 20, 2000, AQMD received five permit applications from El Segundo Power, LLC, for the new construction of the two new CTGs two associated SCRs, and the emergency fire pump. On January 17, 2001, the applicant was informed that they also needed permit applications for a significant Title V permit revision and an application for the ammonia storage tank. The District received the additional two applications on January 18, 2001, and the District deemed the application package complete on January 19, 2001. The application numbers for the original design of the ESPR project are listed in Table 1 below.

Table 1 - Applications for Permits to Construct for Original Design

Application Number	Equipment Description	Date Submitted
378766	7FA CTG Unit No. 5 with duct burner & HRSG	December 20, 2000
378767	7FA CTG Unit No. 7 with duct burner & HRSG	December 20, 2000
378769	Emergency Fire Pump	December 20, 2000
378771	SCR/CO Catalyst Unit No. 5	December 20, 2000
378773	SCR/CO Catalyst Unit No. 7	December 20, 2000
379904	Ammonia Storage Tank	January 18, 2001
379905	Title V Significant Permit Revision	January 18, 2001

MODIFIED DESIGN

The AQMD issued a Final Determination of Compliance for the original design on February 14, 2002, followed shortly in February 2005 by the California Energy Commission (CEC) issuing its final approval for the project as originally designed. Due to unforeseen costs and unexpected litigation by various environmental groups since February 2005, the applicant decided to modify the design of the project by making the following changes as shown in Table 2: Therefore, the proposed project will be configured as shown in the modified design in Table 2 below. Also note that CTGs No. 5 and 7 will be re-designated as CTGs No. 8 and 9.

Table 2 - Original versus Modified Design

Equipment	Original Design	Modified Design
CTGs No. ~~5 & 7~~ 8 & 9	Two General Electric 7FA CTGs with duct burner & HRSG, in a two-on-one configuration, 647 MW total generating capacity (includes steam turbines).	• Two Siemens-Westinghouse SGT6-5000F Rapid Response CTGs, no duct burner, unfired horizontal flow HRSG, one-on-one configuration, 573 MW total generating capacity (includes steam turbines) • Replace once-though cooling with use of dry-cooling
Emergency Fire Pump	Clarke Model JDFP 06WA, diesel fuel, turbocharged, aftercooled, 265 BHP	Eliminated in modified design
SCR Catalyst for Units No. ~~5 & 7~~ 8 & 9	Cormetech, titanium-vanadium, 4,379 ft^3, width 41ft, height 3 ft; length 44 ft.	Cormetech, titanium-vanadium-tungsten, 2,050 ft^3, height 25 ft; width 70 ft.
CO Catalyst for Units No. ~~5 & 7~~ 8 & 9	Englehard, 1,000 ft3, width 41 ft, height 3 ft; length 44 ft.	Englehard, 290 ft3, height 25 ft; width 70 ft

Ammonia Storage Tank	TK-001, underground, carbon-steel, 29% aqueous ammonia, 20,000 gallons, double walled with 3 transfer pumps, with PRV set at 50 psig	No proposed changes

The California Energy Commission (CEC) is the lead agency for this project (00-AFC-14C) and will address all CEQA related issues. CEC will review and amend the original environmental impact report (EIR) issued in February 2005 to account for the proposed modifications in the project design which were proposed after February 2005. Based on an agreement reached with AQMD management on May 23, 2007, El Segundo Power, LLC agreed to submit new applications for the modified design described in Table 2 above. The new applications will replace and supersede the existing open applications. Table 3 below illustrates this transaction. The ammonia storage tank will not be modified and therefore, the original application will be processed along with the new applications.

Table 3 – Existing Open Applications and New Applications for ESPR project

Equipment	Existing Open Applications for Original Design	New Applications for Modified Design
Gas Turbine	378766	470652
Gas Turbine	378767	470656
SCR/CO Catalyst	378771	470653
SCR/CO Catalyst	378773	470654
Title V Significant Revision	379905	470655

Each of the new applications in Table 3 above were submitted to the AQMD on June 21, 2007. AQMD deemed the applications "data adequate" on June 29, 2007. Because the proposed re-powering project will have the potential to generate electricity greater than 25 MW, it will be subject to the federal Acid Rain requirements and therefore the federal Title V permitting requirements apply. The ESPR project is a NOx Major Source and is in the NOx RECLAIM program.

<u>Processing Fee Summary</u>

Table 4 below shows the applicable processing fees for the project. The applicant also included a signed form 400-XPP and the appropriate fees for expedited permit processing. The two (2) CTGs are identical and therefore, one of the CTGs receives a 50% discount off of the original processing fee of $11,671.96. In addition, both of the SCR/CO catalysts are identical and therefore one of these devices receives a 50% discount off of the original processing fee of $2,681.75. The total fees include the normal processing fees multiplied by 1.5 for expedited processing under Rule 301(t). A fee summary is shown in Table 4 below.

Table 4 – Summary of Permit Processing Fees

A/N	Submittal Date	Deemed Data Adequate	Equipment	Schedule	Processing Fee	XPP	TOTAL
470652	6/21/2007	6/29/2007	Gas Turbine No. 8	G	$11,671.96	1.5	$17,507.94
470656	6/21/2007	6/29/2007	Gas Turbine No. 9	G	$5,835.98	1.5	$8,753.97
470653	6/21/2007	6/29/2007	SCR/CO Catalyst No. 8	C	$2,681.75	1.5	$4,022.63
470654	6/21/2007	6/29/2007	SCR/CO Catalyst No. 9	C	$1,340.87	1.5	$2,011.31
379904	1/19/2001	N/A	NH3 Storage Tank	B	$1,865.02	N/A	$1,865.02
470655	6/21/2007	6/29/2007	Title V Application	N/A	$1,394.73	N/A	$1,394.73
						TOTAL PROCESSING FEE	**$35,555.60**

PROCESS DESCRIPTION

The new CTGs consist of two Siemens-Westinghouse (SW) SGT6-5000F rapid response combined cycle gas turbines. Each unit will be equipped with an inlet air filter, an inlet air-cooling system, and steam power augmentation, arranged in a one-on-one configuration. The following table lists the technical specifications for the Siemens-Westinghouse CTGs. Note the specifications in Table 5 below are for a single CTG.

Table 5 – CTG Specifications (Single CTG)

Parameter	Specifications
Manufacturer	Siemens-Westinghouse
Model	SGT6-5000F
Fuel Type	CPUC[1] Quality Natural Gas
Natural Gas Heating Value	1,027.7 BTU/scf
Gas Turbine Heat Input (HHV)	2,096.0 MMBTU/hr at 78°F ambient (peak load)
Fuel Consumption	2.0395 MMSCF/hr[2]
Gas Turbine Exhaust Flow	803,493 DSCFM at 78°F ambient (peak load)
Gas Turbine Exhaust Temperature	361°F at 78°F ambient (peak load)
Heat Recovery Steam Generator	Unfired
NOx Combustion Control	DLN Combustor 9 ppmv
Post Combustion Control	SCR 2.0 ppmv (1-hour average at 15% O_2)
Steam Turbine Power Generation	67.7 MW
Gas Turbine Power Generation	219 MW
Total Gross Power Generation[3]	570 MW
Total Net Power Generation	560 MW
Net Plant Heat Rate, (HHV)	7,311 BTU/kW-hr at ISO conditions
Net Plant Heat Rate, (LHV)	6,596 BTU/kW-hr at ISO conditions
Net Plant Efficiency, (LHV)	52%

The modified ESPR project no longer includes the use of duct burners, or the installation of an emergency firepump engine. The proposed gas turbines/HRSGs will use dry low-NOx combustors, SCR systems, and oxidation catalysts. Finally, the modified project will use horizontal rather then vertical flow HRSGs.

In addition, the modified project includes the use of air-cooled condensers. Two air-cooled condensers (also referred to as dry cooling, or steam turbine fin/fan cooler, or air-cooled back pressure heat exchangers) are utilized for steam turbine exhaust steam heat rejection. This system will replace the previously approved once-through cooling system. Steam exhausted from the steam turbine is condensed in the air-cooled back pressure heat exchanger (BPHX). The BPHX is comprised of a number of cells arranged in rows. The modules consist of horizontal fin tube bundles. The tube bundles are complete with inlet and outlet headers and piped to distribute the wet low pressure steam being condensed and slightly sloped to aid drainage of the saturated water exiting the bundles. Fans force cooler ambient air over tube bundles to condense exhaust steam. The condensate is collected in the condensate receiver tank. With this system there is no direct contact between the steam/water being cooled and the ambient air.

[1] CPUC is the acronym for the California Public Utilities Commission
[2] Represents the maximum possible fuel consumption of the CTG, based on 2,096.0 MMBTU/hr heat input and 1,027.7 BTU/scf fuel heat content
[3] Represents the total power generation from the facility (2 SW CTGs at 219 MW plus 2 ST at 67.7 MW = 573 MW total gross generating capacity)

For the modified ESPR project, each of the CTGs will drive an electrical generator rated at 219.0 MW. In addition, each CTG is equipped with an unfired heat recovery steam generator (HRSG) that drives an electric generator rated at 67.7 MW, for a total gross generating capacity of 573 MW. Net power output, after taking away auxiliary loads of approximately 13 MW, is 560 MW. Fuel consumption is approximately 2,096 MMBTU/hr for each CTG at 78 ° F and 60% relative humidity. During peak CTG operation, steam is injected downstream of the CTG combustors. The addition of this steam increases the mass throughput of the CTG which thereby increases the power output. The steam power augmentation is only used periodically when peak CTG output is necessary. The total nominal gross generating capacity of the modified ESPR project is 573 MW. The modified ESPR project is expected to have an annual capacity factor ranging from 40-60%, depending on weather-related customer demand, load growth, hydro-electric supplies, generating unit retirements, and other factors. Each of the proposed CTGs will be equipped with dry low-NOx combustors (DLN combustors), a selective catalytic reduction (SCR) system for the control of NOx emissions, and oxidation catalyst for the control of CO and VOCs. The existing 20,000-gallon ammonia (NH_3) storage tank at the facility (storing 29% aqueous ammonia) will be used to supply aqueous ammonia to the CTG SCR systems.

The two CTGs will utilize two primary means for the reduction of NOx emissions. The CTGs will be equipped with DLN combustors with 1-hour average NOx concentrations of approximately 9 ppmv on a dry basis at 15% O_2 prior to entry to the selective catalytic reduction (SCR) units. On the back end, an SCR catalyst with ammonia injection will be used downstream of each CTG for further reduction of NOx emissions. As a result, the NOx emissions will be reduced to 2.0 ppmv, 1-hour average, dry basis at 15% O_2. The DLN combustors along with the oxidation catalyst are expected to achieve CO emissions of 2.0 ppmv, 1-hour average, dry basis, at 15% O_2. The DLN combustors along with the oxidation catalyst are expected to achieve VOC emissions of 2.0 ppmv, dry basis at 15% O_2. SOx and PM_{10} emissions will be mitigated through the use of PUC-quality natural gas. Detailed descriptions of the air pollution control system are given in the next section. Tables 6 and 7 below show the specifications for the SCR and oxidation catalyst to be used for the CTGs.

Table 6 – SCR Specifications

Catalyst Properties	Specifications
Manufacturer	Cormetech
Catalyst Description	Titanium/Vanadium/Tungsten with homogeneous honeycomb structure
Catalyst Dimensions	25 feet high, 70 feet wide
Catalyst Volume	2,050 ft^3
Catalyst Life	5 years
Space Velocity	23,000 hr^{-1}
Ammonia Injection Rate	88 lb/hr (at 29% NH_3)
NOx removal efficiency	>90%
NOx at stack outlet	2.0 ppmv at 15% O_2
Ammonia Slip	5.0 ppmv at 15% O_2
Maximum Operating Temperature	750°F
Minimum Operating Temperature	450°F
Warranty Period	5 years
SCR Capital Cost	$1.0 million

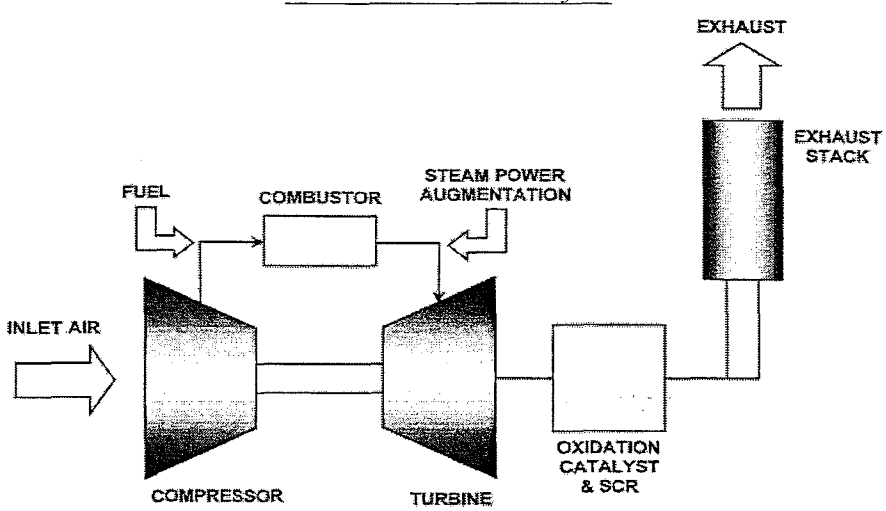
The SCR catalyst will use ammonia injection in the presence of the catalyst to reduce NOx. Diluted ammonia vapor will be injected into the exhaust gas stream via a grid of nozzles located upstream of the catalyst module. The subsequent chemical reaction will reduce NOx to elemental nitrogen (N_2) and water, resulting in NOx concentrations in the exhaust gas at no greater than 2.0 ppmvd at 15% O_2 on a 1-hour average.

Table 7 – Oxidation Catalyst Specifications

Catalyst Properties	Specifications
Manufacturer	Engelhard
Catalyst Description	Stainless steel substrate with alumina platinum catalyst
Catalyst Dimensions	25 feet high, 70 feet wide
Catalyst Volume	290 ft^3
Catalyst Life	5 years
Space Velocity	218,000 hr^{-1}
Area Velocity	82,000 ft/hr
CO removal efficiency	>70%
CO at stack Outlet	2.0 ppmv at 15% O_2
VOC Removal Efficiency	≤ 50%
VOC at Stack Outlet	2.0 ppmv at 15% O_2
Maximum Operating Temperature	1,000°F
Minimum Operating Temperature	300°F
CO Catalyst Capital Cost	$800,000

The exhaust from each catalyst housing will be discharged from a 210-foot tall, 20-foot diameter exhaust stack. Individual CEMS sampling probes will be located in the stacks. The process flow for the CTGs is shown in the diagram below:.

CTG Process Flow Diagram



Aqueous Ammonia Storage Tank

The ammonia will be transported to the site in aqueous form and will have a maximum concentration of 29% by weight. The aqueous ammonia will be stored in the existing 20,000-gallon ammonia storage tank at the El Segundo Generating Station (see Appendix B for a copy of the equipment description of this tank).

Heated Ammonia Vaporization Skid

The ammonia vaporization skids will be used to vaporize the 29% aqueous ammonia so that it can be transferred to the ammonia injection grids. The ammonia vaporization equipment will be shop-assembled and skid mounted for easy field installation. During cold start-up of the CTGs, it will take some time (~10 minutes) before the ammonia injection chamber is hot enough to heat the ammonia for injection. Therefore, each ammonia injection chamber is equipped with an electric pre-heater unit which can be initiated prior to the cold start-ups to ensure that the ammonia is adequately heated prior to injection. The ammonia vaporization skids are typically configured with two dilution air fans (one operating and one spare) and two pre-heater elements (one operating and one spare) housed in a common heater box. In addition, the aqueous ammonia is typically atomized in the ammonia injection chamber and is then fed to the ammonia distribution header.

Ammonia Distribution Header

A carbon steel ammonia distribution header will be used to receive the hot ammonia/air mixture from the ammonia vaporization skid and deliver it evenly to the ammonia injection grid piping. Typically, the injection grid supply piping is equipped with manual butterfly valves and flow instrumentation used for adequate balancing of ammonia flow.

Intermittent Operation

A traditional peaking unit is defined as a turbine which is used intermittently to produce energy on a demand basis and does not operate more than 1,300 hours per year. This definition is found in Rule 2012-Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen (NOx) Emissions, Attachment A-F as amended December 5, 2003. The ESPR project will have the potential to operate for approximately 5,456 hours/year during a non-commissioning year (this number includes start-up, shutdown, and normal operations). Since the annual hours of operation will exceed that which is allowed for a traditional peaking unit under Rule 2012, the Siemens CTGs will not be classified as peaking units in the equipment description. Each CTG is essentially a NOx Major Source as defined in Rule 2012 and will be designated at such on the Facility Permit.

The following page shows a plot plan for the proposed project.

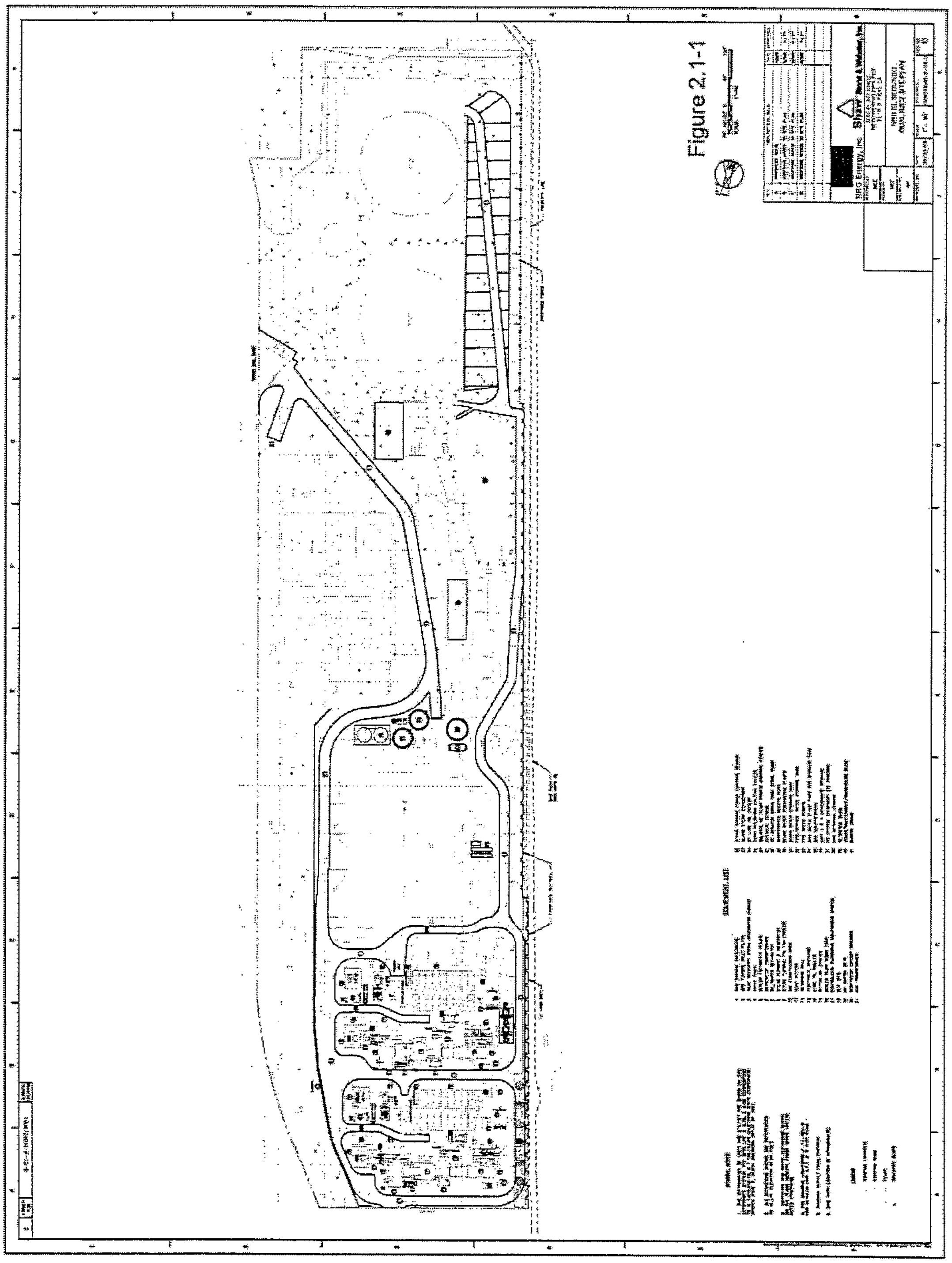


Figure 2.1-1

COMPLIANCE RECORD

A check of the AQMD's Compliance Tracking System database indicates that two Notices to Comply were issued to El Segundo Power, LLC as shown below. The look-back period is 3 years, beginning February 2005 to February 2008.

Notice No.	Issue Date	Violation Date	Violation Description	Status
D03505	1/15/2008	4/27/2007	Rule 2004(b)(1) Ensure all future QCER reports are submitted to the Executive Officer within the 30 day reconciliation period.	In compliance
P03505	1/15/2008	4/27/2007	Rule 2004(b)(1) Ensure all future QCER reports are submitted to the Executive Officer within the 30 day reconciliation period.	In compliance

A check with the AQMD inspector indicated that the appropriate documents have been submitted to AQMD and that the facility is now in compliance.

Performance Warranties

Siemens has submitted a letter to NRG West dated August 10, 2007 (see engineering file) confirming that the Seimens-Westinghouse SGT6-5000F CTGs will are designed to comply with the following emission limits at the stack outlet when the CTGs are operated between 60 percent and 100 percent load.

Table 8 - Warranted Emissions

Pollutant	Warranted Emissions
NOx	2.0 ppmv at 15% O_2
CO	2.0 ppmv at 15% O_2
VOC	2.0 ppmv at 15% O_2
PM10	9.5 lb/hr
NH3 Slip	5.0 ppmv at 15% O_2

CRITERIA POLLUTANT EMISSIONS

The total emissions from the power plant will include the summation of both CTGs, however, for NSR purposes, the emissions are calculated on a per turbine basis. The emissions are based on the following formula and assumptions:

$$EF(\text{lb/MMBTU}) = \text{ppmvd} \times \text{MW} \times \left(\frac{1}{\text{SMV}}\right)\left(\frac{20.9}{5.9}\right) \times F_d$$

where,

ppmvd = Uncontrolled (or controlled) concentration at 15% O_2, dry basis
MW = Molecular weight, lb/lb-mol
SMV = Specific molar volume at 68°F = 385.3 dscf/lb-mol
F_d = Dry oxygen f-factor for natural gas at 68°F = 8,710 dscf/MMBTU

Assumptions:
1. Emissions are based on the worst case operating scenario
2. PM_{10} emissions are based on 0.0045 lb/MMBTU * 2,096 MMBTU/hr = 9.5 lb/hr
3. SO_2 to SO_3 conversion in APC equipment is accounted for in the PM_{10} emission factor
4. SOx emissions are based on 0.25 grains/100 scf
5. 30-Day Averages are based on 730 hours/month of operation

Operating Conditions
The applicant has identified the top 10 operating conditions (OC) in which the fuel consumption per turbine ranges from a low of 1,139 MMBTU/hr (OC8) to a maximum of 2,096 MMBTU/hr (OC3) as shown in Table 9 below:.

Table 9 – Operating Conditions

Parameter	OC1	OC2	OC3	OC4	OC5	OC6	OC7	OC8	OC9	OC10
Ambient Temperature, °F	78	78	78	78	83	83	83	83	62	62
Ambient Pressure, psia	14.64	14.64	14.64	14.64	14.64	14.64	14.64	14.64	14.64	14.64
Fuel Consumption, MMBTU/hr	1,881	1,951	2,096	1,155	1,851	1,930	2,073	1,139	2,004	1,974
Fuel Consumption, scfm	30,805	31,957	34,331	18,917	30,314	31,611	33,955	18,654	32,828	32,342
Exhaust Temperature, °F	1,108	1,100	1,101	1,108	1,113	1,104	1,105	1,113	1,091	1,194
Evaporative Cooler (on/off)	On	On	Off	Off	On	On	Off	On	Off	Off

The worst case scenario from an emissions standpoint occurs during periods of maximum fuel consumption (2,096 MMBTU/hr). Based on the information in Table 9, this occurs at full load (219 MW), ambient temperature of 78°F and 49.6% relative humidity, with evaporative cooler off, and an exhaust temperature of 1,101°F (see "Seimens SGT6-5000F Performance Runs" provided by the applicant and located in List of Appendices at the end of this report). Therefore, to address the worst case scenario, the facility's NSR emissions will be based on the parameters listed in operating condition no. 3.

There are essentially four modes of operation for the CTGs. Emissions from the four operating modes are distinctly different and must be calculated independently. Table 10 gives more detail of the four operating modes.

Table 10 – Operating Modes

Mode	Description
Commissioning	Facility follows a systematic approach to optimizing the performance of the CTGs by fine-tuning each of the units at zero load, partial load, and full load. This procedure is usually performed immediately after construction and prior to commercial operation. Several parameters, such as gas turbine load, degree of combustor tuning, and degree of SCR control may be varied simultaneously or individually during commissioning at the discretion of the applicant. Emissions are expected to be greater during commissioning than during normal operation for some pollutants due to the fact that the combustors may not be optimally tuned and the SCR systems may be only partially operational or not operational at all. The commissioning period is expected to last for approximately 415 hours per turbine over approximately 2 months. This mode affects only the initial year of operation.
Start-up	For a typical combined cycle system, there are three types of starts - cold, warm, and hot. Cold starts occur after the turbine has been down for 72 or more hours, and the start will last approximately 2.5 hours (the time to reach proper operating temperature for full DLN, SCR, and CO catalyst control. Warm starts occur after the turbine has been down 10 to 72 hours, and will last 2 hours. Hot starts occur when

	the turbine has been down less than 10 hours, and typically last 40 minutes. However, El Segundo is employing the Rapid-Response-Combined Cycle (R2C2) technology developed by Siemens-Westinghouse in which the CTGs can be started up in simple cycle mode until full load is achieved, followed by a start-up of the steam turbines. The applicant has indicated that there will be up to two start-ups per day for each CTG. Start up emissions are higher due to the fact that the control equipment has not reached optimal temperature to begin the chemical reactions needed to convert NOx to elemental nitrogen and water.
Normal Operation	Normal operation for combined cycle units occurs after the CTGs and the control equipment are working optimally, when NOx, CO and VOC are each controlled to 2.0 ppmvd at 15% O_2
Shutdown	Shutdown occurs at the initiation of the turbine shutdown sequence and ends with the cessation of CTG firing, and will last approximately 40 minutes thereafter. Typically, the shutdown process will emit less than the start-up process but may emit slightly greater than during normal operation because both H_2O injection into the CTGs and NH_3 injection into the SCR reactor have ceased operation. Emission controls will typically operate down to a level of 60% load, with the final 20 minutes of the shutdown process being partially or completely uncontrolled.

Commissioning Period

Each turbine will go through a series of tests during the commissioning period to prepare for commercial operation. According to the applicant, the specific commissioning tests / activities scheduled for each CTG will include the following:

- FSNL, excitation test
- CTG test, up to 40% load
- Steam blow, HRSG tuning
- Steam blow, HRSG restoration, install SCR/CO catalyst
- Establish vacuum / HRSG tuning / BOP tuning
- CTG load test, by-pass valve and safety valve tuning
- Installation of emissions test equipment
- By-pass operation / steam turbine initial roll and trip test
- By-pass operation steam turbine load test
- CTG on by-pass / steam turbine load test
- Combined cycle drift test
- Emissions tuning / drift test
- Pre-performance drift test
- RATA / pre-performance testing / source testing
- Pre-performance testing / source testing
- Performance testing
- Cal-ISO certification

It will be assumed that the commissioning of both units will be simultaneous to address the worst case scenario. The durations and corresponding pollutant emission rates of the individual commissioning tests and activities for each combustion turbine are shown in Table 11 below. The applicant did not provide emissions data for SOx during the commissioning period:

Table 11 – CTG 8 & 9 Individual Commissioning Tests (per turbine)

Activity	Duration (hours)	CTG load (%)	Pollutant Emission Rates (lbs)			
			NOx	CO	VOC	PM10
FSNL, Excitation test	8	0	376	30,501	1,310	93
CTG Testing @ 40% load	8	0-40	1,601	17,683	677	102
Steam Blow / HRSG Tuning	24	0-50	2,762	52,859	1,682	255
Steam Blow	12	0-50	1,007	9,147	713	111
Steam blow Restoration, install SCR/CO Cat	0	0	0	0	0	0
Establish vacuum/HRSG tuning/BOP tuning	16	60	239	908	136	137
Establish vacuum/BOP tuning	16	60	239	908	136	137
CTG load test & bypass valve tuning	32	60	478	1,816	272	274
CTG load test & bypass valve tuning/safety valve test	12	75	222	842	92	106
CTG base load, commissioning of NH_3 system	12	100	260	852	97	117
CTG load test & bypass valve tuning	12	100	260	852	97	117
Bypass operation, STG initial roll & trip test	10	0-60	182	869	113	89
Bypass operation/ STG load test	16	0-60	239	908	136	137
CTG on bypass/STG load test	16	0-100	317	867	105	152
Combined cycle testing/drift test	24	0-100	386	615	93	215
Combined cycle testing/drift test	24	100	380	374	73	214
Emissions tuning/drift test	24	50-100	520	1,704	194	234
Pre-performance testing/drift test	36	100	780	2,556	291	351
RATA/Pre-performance testing/source testing	15	100	303	864	103	143
Pre-performance testing/source testing	14	100	289	860	101	134
Pre-performance testing/source testing	12	50-100	260	852	97	117
Remove emissions test equipment	0	0	0	0	0	0
Water wash & performance preparation	0	0	0	0	0	0
Performance testing	48	100	858	1,796	240	442
CALISO Certification	12	50-100	260	852	97	117
CALISO Certification	12	100	260	852	97	117
TOTALS	**415**	/////////////	**12,478**	**130,337**	**6,952**	**3911**

Start-Up Emissions

Siemens-Westinghouse has provided start-up emission curves for the SGT6-5000F CTG coupled with the SST-800 ST steam turbine. The combined cycle arrangement for the proposed power plant will be a one-on-one configuration. A total of three curves were provided for plant down times of 8 hours, 16 hours and 48 hours. These curves are proprietary and confidential to Siemens-Westinghouse and will be contained in the engineering file for internal reference only. As shown in all three curves, regardless of the time the CTG is down, the time required for the CTG to reach full load is 12 minutes. This is true because the steam generated by the heat recovery steam generator during a CTG start-up is routed to the air-cooled condensers until the steam is needed by the steam turbine. This means that essentially the steam turbine can be by-passed, allowing the plant to start-up in simple cycle mode, and as a result, the start-up of the steam turbine does not slow down or impede the start-up of the CTG. The curves also show that the longer the CTG is down, the longer the time for the steam turbine to reach full load. Consequently, the start-up times and associated start-up emissions attributed to the CTG are unaffected by the length of time the unit is down. Therefore, there is no need to distinguish between hot, warm, and cold start-ups even though the proposed power plant will operate in combined cycle mode. This rapid-start feature is unique to this highly efficient combined cycle configuration from Siemens-Westinghouse and is known as "Rapid Response-Combined Cycle (R2C2). It allows the facility to significantly reduce start-up emissions as compared with traditional combined cycle configurations in which the steam turbine is not by-passed and the entire CTG–ST train is started simultaneously. Similar rapid-start configurations with the Siemens-Westinghouse combined cycle CTGs are being proposed at the City of Vernon and the San Gabriel Generating Station. Although the specific configurations at these facilities do not allow for a complete by-pass of the steam turbine such as with the proposed R2C2 configuration at El Segundo, the configurations at these facilities use an auxiliary boiler to keep the system pre-heated to a temperature such that the system can start-up under warm or hot conditions, and minimize the number of cold starts.

Table 12 below is the total estimated start-up and shutdown emissions for the SGT6-5000F CTG as provided by Siemens-Westinghouse.

Table 12 - Total Estimated Start-up and Shutdown Emissions, per CTG

Mode	Time, minutes	Total Emissions per Event (pounds)			
		NOx	CO	VOC	PM10
Start-up @ 62 deg F	12	24	259	12	3
Shutdown @ 62 deg F	7	10	131	5	1
Start-up @ 41 deg F	12	25	267	13	3
Shutdown @ 41 deg F	7	10	135	5	1

The applicant anticipates a maximum of 200 hours/year during which a CTG start-up will occur. During a CTG start-up, there are approximately 12 minutes in which elevated emissions occur. Therefore, the hourly emission rates during a start-up hour will be based on 12 minutes of uncontrolled emissions followed by 48 minutes of normal operation in which BACT levels are assumed. The applicant has also indicated that there will be up to 200 hours per year of shutdowns which will comprise 53 minutes of normal operation at which BACT levels are assumed followed by 7 minutes of elevated emissions as the catalyst gradually cools down.

Normal Operations

The emissions during normal operations are assumed to be fully controlled to Best Available Control Technology (BACT) levels, and exclude emissions due to commissioning, start up and shutdown periods, which are not subject to BACT levels. Hourly, monthly, annual, and 30-day averages are calculated and shown in Appendices A through C.

Emissions During A Commissioning Year

Tables 13 through 15 below show the cumulative emissions during a commissioning year from both gas turbines which include commissioning, start-up, shutdown and normal operation.

Table 13 – Mass Emission Rates, lb/hr (Commissioning Year)

	Emissions, lb/hr					
2-Siemens SGT6-5000F CTGs	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	30.88	18.80	10.74	2.93	18.98	28.54
Start up	112.06	834.84	34.60	2.93	18.98	
Shutdown	71.00	442.36	19.48	2.93	18.98	
Commissioning	60.14	628.08	33.50	2.93	18.98	
TOTALS	**274.08**	**1,924.08**	**98.32**	**11.72**	**75.92**	**28.54**

Table 14 – Mass Emission Rates, lb/month (Commissioning Year)

	Emissions, lb/month					
2-Siemens SGT6-5000F CTGs	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operation, Start up, Shutdown & Commissioning (1-30)	13,129.28	236,291.44	10,922.08	519.76	3,357.08	
Normal Operation, Start up, Shutdown & Commissioning (31-49)	24,447.88	33,650.96	8,276.28	2,131.60	13,836.82	
HIGHEST MONTH	**24,447.88**	**236,291.44**	**10,922.08**	**2,131.60**	**13,836.82**	**14,070.22**

Table 15 – Mass Emission Rates, lb/year (Commissioning Year)

	Emissions, lb/year					
2-Siemens SGT6-5000F CTGs	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	143,314.08	87,250.80	49,844.34	13,551.72	88,179.00	132,454.14
Start up	22,412.00	166,960.00	6,920.00	584.00	3,800.00	
Shutdown	14,200.00	88,472.00	3,896.00	584.00	3,800.00	
Commissioning	24,958.10	260,678.10	13,902.50	1,211.80	7,885.00	
TOTALS	**204,884.18**	**603,360.90**	**74,562.84**	**15,931.52**	**103,664.00**	**132,454.14**

Emissions During A Non-Commissioning Year

Tables 16 through 18 below show the cumulative emissions during a non-commissioning year from both CTGs which include start-up, shutdown and normal operation.

Table 16 – Mass Emission Rates, lb/hr (Non-Commissioning Year)

	Emissions, lb/hr					
2-Siemens SGT6-5000F CTGs	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	30.88	18.80	10.74	2.92	9.50	28.54
Start up	112.06	834.84	34.60	2.92	9.50	
Shutdown	71.00	442.36	19.48	2.92	9.50	
TOTALS	**213.94**	**1,296.00**	**64.82**	**8.76**	**28.50**	**28.54**

Table 17 – Mass Emission Rates, lb/month (Non-Commissioning Year)

	Emissions, lb/month					
2-Siemens SGT6-5000F CTGs	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	18,713.28	11,392.80	6,508.44	1,769.52	11,514.00	17,295.24
Start up	6,944.00	51,760.08	2,145.20	181.04	1,178.00	
Shutdown	4,402.00	27,426.32	1,207.76	181.04	1,178.00	
TOTALS	**30,059.28**	**90,579.20**	**9,861.40**	**2,131.60**	**13,870.00**	**17,295.24**

Table 18 – Mass Emission Rates, lb/year (Non-Commissioning Year)

	Emissions, lb/year					
2-Siemens SGT6-5000F CTGs	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	156,129.28	95,052.80	54,301.44	14,763.52	96,064.00	144,298.24
Start up	22,412.00	166,968.00	6,920.00	584.00	3,800.00	
Shutdown	14,200.00	88,472.00	3,896.00	584.00	3,800.00	
TOTALS	**192,741.28**	**350,492.80**	**65,117.44**	**15,931.52**	**103,664.00**	**144,298.24**

30-Day Averages

The 30 Day Average emissions are calculated in Appendix B for both a commissioning and non-commissioning year for the worst case operating scenario. The worst case operating scenario was defined as OC3 in Table 9 above.

Table 19 is a comparison of the 30-day averages *for a single permit unit* for both a commissioning year and a non-commissioning year. The maximum 30-day averages for each pollutant are shown as shaded in Table 19 below:

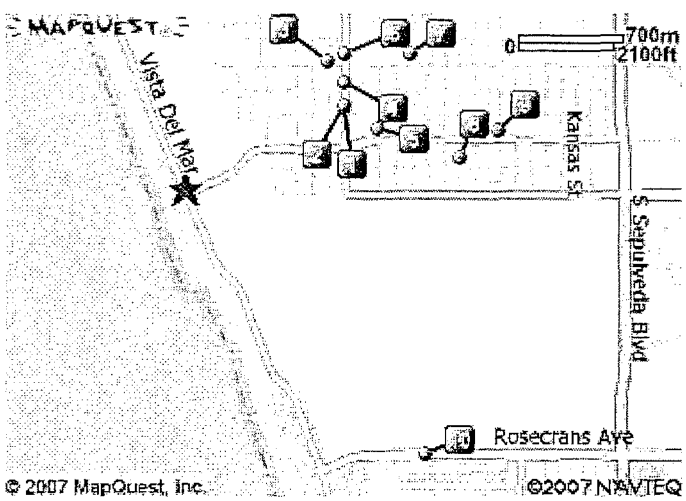
Table 19 - 30-Day Average (Permit unit)

	NOx	CO	VOC	SOx	PM_{10}
30 Day Average (Commissioning Year)	407	**3,938**	**182**	36	231
30 Day Average (Non-Commissioning Year)	**501**	1,510	164	**36**	**231**

SCHOOL LOCATIONS

This proposed project is located at 301 Vista Del Mar El Segundo, CA. The school located nearest to the facility, Little Palette School, is at least 0.74 miles away (well beyond 1,000 feet) from the site as measured by the Mapquest program found at *http://www.mapquest.com*. The remaining nine schools are located even further away from the site, as shown in the table below. The school locations in relation to the project site are shown graphically in the illustration below.

No	Name of School	Address	Mapquest Distance Miles
1	Little Palette School	425 Main Street, El Segundo	0.74
2	Flight Services Unlimited	426 ½ Main Street, El Segundo	0.75
3	Richmond Street Elementary	615 Richmond Street , El Segundo	0.78
4	Real Estate Center	531 Main Street No. 935, El Segundo	0.79
5	El Segundo Babe Ruth	338 Eucalyptus Dr, El Segundo	0.84
6	El Segundo High School	640 Main Street, El Segundo	0.85
7	El Segundo School District Adm	641 Sheldon St, El Segundo	1.08
8	St Anthony Catholic School	233 Lomita St, El Segundo	1.14
9	El Segundo Middle School	332 Center St, El Segundo	1.32
10	Creative Minds Integrated	590 Rosecrans Ave, Manhattan Beach	1.42



PROHIBITORY RULE EVALUATION

RULE 212-Standards for Approving Permits

Rule 212 requires that a person shall not build, erect, install, alter, or replace any equipment, the use of which may cause the issuance of air contaminants or the use of which may eliminate, reduce, or control the issuance of air contaminants without first obtaining written authorization for such construction from the Executive Officer. Rule 212(c) states that a project requires written notification if there is an emission increase for ANY criteria pollutant in excess of the daily maximums specified in Rule 212(g), if the equipment is located within 1,000 feet of the outer boundary of a school, or if the MICR is equal to or greater than one in a million (1EE-6) during a lifetime (70 years) for facilities with more than one permitted unit, source under Regulation XX, or equipment under Regulation XXX, unless the applicant demonstrates to the satisfaction of the Executive Officer that the total facility-wide maximum individual cancer risk is below ten in a million (10EE-6) using the risk assessment procedures and toxic air contaminants specified under Rule 1402; or, ten in a million (10EE-6) during a lifetime (70 years) for facilities with a single permitted unit, source under Regulation XX, or equipment under Regulation XXX. The total facility wide residential MICR is expected to be less than 1EE-6, and the facility is located more than 1,000 feet from a school, however, since the emissions of criteria pollutants for the facility exceed the thresholds in Rule

212(g), a public notice is required in accordance with the requirements of Rule 212. A public notice will be issued followed by a 30-day public comment period prior to issuance of a permit.

RULE 401-Visible Emissions
This rule limits visible emissions to an opacity of less than 20 percent (Ringlemann No.1), as published by the United States Bureau of Mines. It is unlikely, with the use of the SCR /CO catalyst configuration that there will be visible emissions. However, in the unlikely event that visible emissions do occur, anything greater than 20 percent opacity is not expected to last for greater than 3 minutes. During normal operation, no visible emissions are expected. Therefore, based on the above and on experience with other CTGs, compliance with this rule is expected.

RULE 402-Nuisance
This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property. The two new combined cycle CTGs will be operated with SCR and CO catalysts to comply with BACT and are expected to be cleaner burning than their predecessor utility boilers and are not expected to create a public nuisance based on experience with similar CTGs. Therefore, compliance with Rule 402 is expected.

RULE 403-Fugitive Dust
The purpose of this rule is to reduce the amount of particulate matter entrained in the ambient air as a result of man-made fugitive dust sources by requiring actions to prevent, reduce, or mitigate fugitive dust emissions. The provisions of this rule apply to any activity or man-made condition capable of generating fugitive dust. This rule prohibits emissions of fugitive dust beyond the property line of the emission source. The applicant will be taking steps to prevent and/or reduce or mitigate fugitive dust emissions from the project site. Such measures include covering loose material on haul vehicles, watering, and using chemical stabilizers when necessary. The installation and operation of the CTGs is expected to comply with this rule.

RULE 407-Liquid and Gaseous Air Contaminants
This rule limits CO emissions to 2,000 ppmvd and SO_2 emissions to 500 ppmvd, averaged over 15 minutes. For CO, the CTGs will be required to meet the BACT limit of 2.0 ppmvd at 15% O_2, 1-hr average, and will be conditioned as such. For SO_2, equipment which complies with Rule 431.1 is exempt from the SO_2 limit in Rule 407. The applicant will be required to comply with Rule 431.1 and thus the SO_2 limit in Rule 407 will not apply.

RULE 409-Combustion Contaminants
This rule restricts the discharge of contaminants from the combustion of fuel to 0.23 grams per cubic meter (0.1 grain per cubic foot) of gas, calculated to 12% CO_2, averaged over 15 minutes. The equipment is expected to meet this limit based on the calculations shown below:

Estimated exhaust gas	=	803,493 DSCFM = 48.21 mmscf/hr
Maximum PM_{10} Emissions	=	9.5 lb/hr
Estimated CO_2 in exhaust	=	3%

$$\text{Grain Loading} = \frac{(9.5\ \text{lb/hr})(7000\ \text{gr/lb})}{48.21\text{EE}6\ \text{scf/hr}} \times \frac{12}{3} = 0.005517\ \text{gr/dscf} << 0.1\ \text{gr/dscf}$$

RULE 431.1-Sulfur Content of Gaseous Fuels

El Segundo Power, LLC will use pipeline quality natural gas which will comply with the 16 ppmv sulfur limit, calculated as H_2S, specified in this rule. Natural gas supplied by the Gas Company also has a sulfur content of less than 0.25 gr/100scf, which is equivalent to a sulfur concentration of about 4 ppmv. It is also much less than the 1 gr/100scf limit typical of pipeline quality natural gas. Compliance is expected.

RULE 474-Fuel Burning Equipment-Oxides of Nitrogen

Superseded by NOx RECLAIM.

RULE 475-Electric Power Generating Equipment

This rule applies to power generating equipment rated greater than 10 MW installed after May 7, 1976. Requirements specify that the equipment must comply with a PM_{10} mass emission limit of 11 lb/hr or a PM_{10} concentration limit of 0.01 grains/dscf. Compliance is demonstrated if either the mass emission limit or the concentration limit is met. The PM_{10} mass emissions from each turbine is estimated to be 9.5 lb/hr. The estimated grain loading is less than 0.01 grain/dscf (see calculations under Rule 409 analysis). Therefore, compliance is expected. Compliance will be verified through performance tests.

NEW SOURCE REVIEW (NSR) ANALYSIS

The following section describes the NSR analysis for El Segundo Power, LLC proposed re-powering project. The facility can comply with NSR either by qualifying for various exemptions from or by demonstrating compliance with the following rules. Since the proposed installation of the new combined cycle CTGs will be treated as installation of new equipment, there are no exemptions from any portions of NSR. Therefore each of the following NSR rules will apply. Each individual permit unit (in this case a permit unit is defined as one gas turbine) is evaluated for compliance with the rules in Table 20 below.

Table 20 - Applicable NSR Rules for El Segundo Power, LLC

Applicable NSR Rules for Non-RECLAIM Pollutants (SOx, VOC, PM_{10})	Applicable NSR Rules for RECLAIM Pollutants (NOx)
Rule 1303(a)-BACT	Rule 2005(b)(1)(A)-BACT
Rule 1303(b)(1)-Modeling	Rule 2005(b)(1)(B)-Modeling
Rule 1303(b)(2)-Offsets	Rule 2005(b)(2)-Offsets
Rule 1303(b)(3)-Sensitive Zone Requirements	Rule 2005(e)-Trading Zone Restrictions
Rule 1303(b)(4)-Facility Compliance	Rule 2005(g)(1)-Statewide Compliance
	Rule 2005(g)(3)-Compliance through CEQA
	Rule 2005(h)-Public Notice
	Rule 2005(i)-Rule 1401 Compliance
	Rule 2005(j)-Compliance with Fed/State NSR

RULE 1303(a) and Rule 2005(b)(1)(A)-BACT – Siemens CTGs

Both rules state that the Executive Officer shall deny the Permit to Construct for any new source which results in an emission increase of any non-attainment air contaminant, any ozone depleting compound, or ammonia unless the applicant can demonstrate that BACT is employed for the new source. El Segundo

Power, LLC is a new source with a potential for an increase in emissions and therefore, BACT is required. Both CTGs proposed for construction will be configured in combined cycle. As of the date of this evaluation, BACT for combined cycle gas turbines is shown in Table 21 below:

Table 21 - BACT Requirements for Combined Cycle Gas Turbines

NOx	VOC	PM_{10}/SOx	NH_3
2.0 ppmvd, at 15% O_2, 1-hour rolling average	2.0 ppmvd, at 15% O_2, 1-hour rolling average	Pipeline quality natural gas w/ S content ≤ 1 grain/100 scf	5.0 ppmvd at 15% O_2, 1-hour rolling average

This information was based on a search of the BACT Clearinghouse database and the latest information available for permits issued to Vernon City (A/N 394164) and Magnolia Power (A/N 386305). The turbines at El Segundo Power operate in combined cycle similar to those at the Vernon and Magnolia projects. The emission levels in Table 19 are now officially considered BACT for combined cycle CTGs. The applicant is proposing the emission levels for this project shown in Table 22 below.

Table 22 - Proposed BACT for Siemens Combined Cycle CTGs

NOx	VOC	PM_{10}/SOx	NH_3
2.0 ppmvd, @ 15% O_2, 1-hour average	2.0 ppmvd, @ 15% O_2, 1-hour average	PUC quality natural gas w/ S content ≤ 1 grain/100 scf	5.0 ppmvd @ 15% O_2, 1-hour average

The proposed control levels in the table above will comply with the current BACT requirements for each pollutant including NH_3. The turbines are expected to comply with BACT and will be verified by a performance test after construction, commissioning, and initial operation of the equipment.

RULE 1303(a)-BACT – Ammonia Storage Tank

A pressure relief valve which will be set at no less than 50 psig will control ammonia emissions from the storage tank. In addition, a vapor return line will be used to control ammonia emissions during storage tank filling operations. Based on the above, compliance with BACT requirements is expected.

Based on the above BACT analysis, the two (2) CTGs, their SCR/CO catalyst systems, and the ammonia tank will comply with the current BACT requirements found in Regulation XIII (for the non-RECLAIM pollutants) and in Regulation XX (for the RECLAIM pollutants). BACT for all equipment is satisfied.

RULE 1303(b)(1) and Rule 2005(b)(1)(B) - Modeling

The air dispersion modeling and health risk analysis (HRA) for the proposed repowering project was submitted to AQMD with the original application package. The analyses included the HRA results from HARP Version 1.3. AQMD modeling staff reviewed the applicant's analyses for both air quality modeling and health risk assessment (HRA). Modeling staff provided their comments in a memorandum from Ms. Jill Whynot to Mr. Mike Mills dated November 15, 2007. A copy of this memorandum is contained in the engineering file. Staff's review of the modeling and HRA analyses concluded that the applicant used EPA ISCST3 model version 02035 along with the appropriate model options in the analyses for NO_2, CO, PM_{10}, and SO_2. The applicant modeled both the cumulative and individual permit unit impacts for the project. The memorandum states that the modeling as performed by the applicant conforms to the District's dispersion modeling requirements. The applicant's analysis considered the effects of both simple and complex terrain, inversion break-up and shoreline fumigation impacts were also considered. Because the stacks are mounted on top of a structure, building downwash effects were taken into account in the analysis by implementing the Building Profile Input Program (BPIP). Meteorological data including hourly wind speeds and direction, atmospheric stability, and surface meteorological data including hourly wind speeds and direction were taken from the Lennox Monitoring Station and included in the applicant's analysis. Upper air meteorological data including atmospheric stability and mixing heights were collected from Los Angeles International Airport monitoring station. No significant deficiencies were reported.

Table A-2 shown below is found in AQMD Rule 1303 and lists the most stringent ambient air quality standards and allowable change in concentration for each air contaminant. The appropriate averaging times are also listed.

Table A-2
Most Stringent Ambient Air Quality Standard and
Allowable Change in Concentration
For Each Air Contaminant/Averaging Time Combination

Air Contaminant	Averaging Time	Most Stringent Air Quality Standard		Significant Change in Air Quality Concentration	
Nitrogen Dioxide	1-hour	25 pphm	500 $\mu g/m^3$	1 pphm	20 $\mu g/m^3$
	Annual	5.3 pphm	100 $\mu g/m^3$	0.05 pphm	1 $\mu g/m^3$
Carbon Monoxide	1-hour	20 ppm	23 mg/m^3	1 ppm	1.1 mg/m^3
	8-hour	9.0 ppm	10 mg/m^3	0.45 ppm	0.50 mg/m^3
Suspended Particulate Matter <10µm (PM_{10})	24-hour		50 $\mu g/m^3$		2.5 $\mu g/m^3$
	AGM[4]		30 $\mu g/m^3$		1 $\mu g/m^3$
Sulfate	24-hour		25 $\mu g/m^3$		1 $\mu g/m^3$

The applicant is required under Rule 1303(b)(1) to demonstrate compliance with one of the following requirements: (a) The most stringent air quality standard shown in Table A-2 above, or (b) The significant change in air quality concentration standards shown in Table A-2 above, if the most stringent air quality standards are exceeded The applicant has provided the following modeled maximum project impacts for each individual turbine. Therefore, the numbers in the table below are on a permit unit basis. Each individual turbine plus the background concentration is less than the most stringent standard.

Maximum Project Impacts for Attainment Pollutants

	Average	CTG No.8 ($\mu g/m^3$)	CTG No.9 ($\mu g/m^3$)	Bkgrnd ($\mu g/m^3$)	Most Stringent Standard ($\mu g/m^3$)	Comply (Yes/No)
NOx	1-hr	58.8	59.2	162	470	Yes
	Annual	0.14	0.15	38	100	Yes
SO_2	1-hr	1.52	1.52	110	650	Yes
	3-hr	0.79	0.79	87	1,300	Yes
	24-hr	0.15	0.15	31	105	Yes
	Annual	0.01	0.01	13	80	Yes
CO	1-hr	1,120	1,128	4,600	23,000	Yes
	8-hr	524	504	2,645	10,000	Yes

Since PM_{10} is a non-attainment pollutant, it is required to comply with the 24-hour and annual PM_{10} significance levels in the table below. This table shows the 24-hour and the annual significance levels for turbines 1 through 5.

[4] AGM is the acronym for Annual Geometric Mean

Significance Modeling for Non-Attainment Pollutants, (μg/m^3)

Equipment	24-hour PM_{10} Concentration	24 hour PM10 Significance Level	Annual PM10 Concentration	Annual PM10 Significance Level	Comply (Yes/No)
Turbine No. 8	0.64	2.5	0.085	1	Yes
Turbine No. 9	0.63	2.5	0.087	1	Yes

RULE 1303(b)(2) and Rule 2005(b)(2)-Offsets
REQUIRED OFFSETS

There will be a net increase in PM_{10}, VOC, and SOx emissions as a result of the project. Therefore, emission offsets are needed for these pollutants. The amount of offsets needed is based on the maximum emission increase from the new equipment (including startups) less the emissions from the existing boilers. Since the applicant is replacing existing utility steam boilers with new combined cycle equipment, the offsets exemption included in Rule 1304(a)(2) applies to this project. Also, since the existing boilers have been shutdown, the applicant is allowed to mitigate the emissions increase using the calculation procedure specified in Rule 1306(c). Based on the agreement between El Segundo Power, LLC and AQMD management and legal staff which is discussed in detail in the May 11, 2007 email (see engineering file), it was agreed to and concluded by both parties that El Segundo Power, LLC will be eligible to use the previous Rule 1304(a)(2) provisions for replacement of utility boilers with combined cycle CTGs utilizing Rule 1306 calculation methodology and would still qualify to access Rule 1309.1 – Priority Reserve. The amount of offsets obtained from the Priority Reserve will, in accordance with Rule 1309.1, be at 1.2-to-1.0 offset ratio, and the cost of these credits will be based on the version of Rule 1309.1 in effect at the time of issuance of the AQMD permits. Table 23 below shows the required emission offsets using the Rule 1304 provisions for replacement of utility boilers with combined cycle CTGs. Table 24 below shows the the ERC certificates presently held by El Segundo Power, LLC.

Table 23 - Required Emission Offsets

		CO	VOC	PM10	SOx
30-Day Averages	CTG No. 8	3,938	182	231	36
	CTG No. 9	3,938	182	231	36
Rule 1304 Multiplier[5]		0.3892	0.3892	0.3892	0.3892
Revised 30-Day Average	CTG No. 8	1,533	71	90	14
	CTG No. 9	1,533	71	90	14
NSR Offset Ratio		1.2	1.2	1.2	1.2
Offsets Required	CTG No. 8		85	108	17
	CTG No. 9		85	108	17
ERCs Purchased		N/A	(146)	(24)	(45)
Priority Reserve Credits		N/A	N/A	(192)	N/A
Remaining Balance to be offset		N/A	24	0	0

The facility's maximum monthly and annual fuel usage for the simultaneous operation of the two (2) CTGs will be 3,000.16 mmscf and 22,423.09 mmscf, respectively, based on the OC3. The calculations are shown below and a monthly fuel cap will be included on the Facility Permit as a condition.

[5] Combined cycle CTGs = 573 MW
Removal of boilers 1 & 2 = 350 MW.
Multiplier = (573-350)/573 = 0.3892

Monthly:
CTGFuel= (2,096 MMBTU/hr)(1 scf/1,020 BTU)(730 hr/month)(2 CTGs) = 3,000.16 MMscf/month

Annually:
CTGFuel= (2,096 MMBTU/hr)(1 scf/1,020 BTU)(5,456 hr/year)(2 CTGs) = 22,423.09 MMscf/year

Table 24 - ERC Certificates held by El Segundo Power, LLC

Pollutant	Cert. No.	Date of Purchase	Origin/Zone	Seller	Amount of ERC (lb/day)
SOx	AQ003333	12/2/00	Lockheed Advanced Dev Co /01	ARCO Products	17
	AQ003336	12/2/00	Union Pacific Resources /01	ARCO Products	19
	AQ006561	3/29/07	Monsanto Co. /01	Monsanto Co.	9
				SOx Grand Total	**45**
VOC	AQ006559	3/28/07	Kimball Int'l / Harpers Inc /01	Kimball Int'l / Harpers Inc	6
	AQ004686	9/25/02	Kimball Int'l / Harpers Inc /01	National Offsets	25
	AQ004580	7/31/02	Allied Signal / Honeywell /01	Allied Signal / Honeywell	20
	AQ003722	5/19/01	Allied Signal / Honeywell /01	Allied Signal / Honeywell	95
				VOC Grand Total	**146**
PM_{10}	AQ003352	12/21/00	Aerochem /01	Aerochem	6
	AQ003462	2/7/01	Friction Materials /01	Multifuels	2
	AQ003550	3/21/01	Paramount Perlite /01	Multifuels	2
	AQ003568	4/3/01	Ball Incon Glass /01	Multifuels	3
	AQ004145	8/14/01	American National Can /01	American National Can	1
	AQ004322	12/27/01	Henkel Corp / Emery Group /01	Intergen North American Dev	5
	AQ004323	12/27/01	City of South Gate / 01	Intergen North American Dev	3
	AQ004326	12/27/01	LA Export Terminal Inc /01	Intergen North American Dev	2
				PM_{10} Grand Total	**24**

RULES 1303(b)(3)-Sensitive Zone Requirements and 2005(e)-Trading Zone Restrictions

Both rules state that credits must be obtained from the appropriate trading zone. In the case of Rule 1303(b)(3), facilities located in the South Coast Air Basin are subject to the Sensitive Zone requirements specified in Health & Safety Code Section 40410.5. El Segundo Power, LLC is located in Zone 1a and is therefore eligible to obtain its ERCs from Zone 1 only. Similarly in the case of Rule 2005(e), El Segundo Power, LLC, because of its location may obtain RTCs from Zone 1 only. Compliance is expected because the ERCs and RTCs originated from the facility shutdown, which is located in Zone 1, and will be used in Zone 1. Any additional offsets will come from the Priority Reserve.

RULE 1303(b)(4)-Facility Compliance

The new facility will comply with all applicable Rules and Regulations of the AQMD.

RULE 1303(b)(5)-Major Polluting Facility

El Segundo Power, LLC has addressed the alternative analysis, statewide compliance, protection of visibility, and CEQA compliance requirements of this rule for NOx. These requirements are summarized below.

Rule 1303(b)(5)(A) – Alternative Analysis

Requires the applicant to conduct an analysis of alternative sites, sizes, production processes, environmental control techniques for the re-powering project and to demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with this project. El Segundo Power, LLC has performed a comparative evaluation of alternative sites as part of the AFC process and has concluded that the benefits of providing additional electricity and increased employment in the surrounding area will outweigh the environmental and social costs incurred in the construction and operation of the proposed facility.

Rule 1303(b)(5)(B) – Statewide Compliance
El Segundo Power, LLC has submitted a letter to the AQMD dated June 13, 2007 (see file) stating that any and all facilities that El Segundo Power, LLC owns or operates in the State of California (including the proposed re-powering project) are in compliance or are on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act. Therefore, compliance is expected.

Rule 1303(b)(5)(C) – Protection of Visibility
Modeling is required if the source is within a Class I area and the NOx and PM_{10} emissions exceed 40 TPY and 15TYP respectively. Since the nearest Class I area is located over 28 miles from the El Segundo site, modeling from plume visibility is not required, however, the applicant has provided modeling impact data for the Class I areas as part of the AFC process. Compliance is expected.

Rule 1303(b)(5)(D) – Compliance through CEQA
The California Energy Commission's (CEC) certification process is essentially equivalent to CEQA. Since the applicant is required to receive a certification from the CEC, the applicable CEQA requirements and deficiencies will be addressed. Compliance is expected.

<u>Rule 1309.1 – Priority Reserve</u>
El Segundo Power, LLC has requested access to the Priority Reserve for PM_{10} offsets. In order to qualify for access to the Priority Reserve, there are several requirements which El Segundo Power, LLC must comply with in accordance with as shown below:

<u>Rule 1309.1(b)(4)(A): Electrical Generating Facility (EGF)</u>:
This rule states that an EGF is qualified to draw credits form the Priority Reserve provided the facility complies with both (1) and (2) below:

(1) It generates 50 MW or greater of electricity for distribution in the state or municipality owned grid system (net generator), and

(2) Such facility must submit a complete application for certification (AFC) to the California Energy Commission or District permit to construct application during calendar years 2000 through 2003 or 2005 through 2008 and which applications are directly related to the production of electricity such that for projects submitting applications in 2005 through 2008, the electrical generation unit or power plant site and related facility will be the subject of an environmental impact report, negative declaration or other document prepared pursuant to a certified regulatory program, and in accordance with Public Resources Code Section 21080 (b)(6). El Segundo Power, LLC will provide 573 MW of electricity to the SCE grid and has submitted an AFC package to the CEC in

calendar year 2000 along with applications for permits to construct to AQMD. Therefore, El Segundo Power, LLC complies with this requirement.

Rule 1309.1(B)(5)(A)(ii)(a) and (b):
The specific requirements for a facility located in Zone 1 are listed in Rule 1309.1(B)(5)(A)(ii)(a) and (b) and are summarized in Table 25 below:

Table 25 - Rule 1309.1 Zone 1 Specific Requirements

Rule Subpart	Specific Requirements
Rule 1309.1(B)(5)(A)(ii)(a)	Unit PM_{10} emissions ≤ 0.060 lb/MW-hr
Rule 1309.1(B)(5)(A)(ii)(b)	Unit NOx emissions ≤ 0.080 lb/MW-hr

The NOx and PM_{10} emissions from each gas turbine must not exceed 0.080 lb/MW-hr and 0.060 lb/MW-hr, respectively, as determined at ISO conditions of 14.7 psia, 60 degrees F, and 60% relative humidity. As shown in Table 26 below, the emissions from both of the CTGs will comply with Rules 1309.1(b)(5)(A)(ii)(a) and (b). Therefore, El Segundo Power, LLC will comply with Rules 1309.1 (b)(5)(A)(ii)(a) and (b)

Table 26 - NOx and PM_{10} Emissions

Equipment	Pollutant	lb/MW-hr, at ISO conditions	Maximum Allowable lb/MW-hr	Comply (Yes/No)
Gas Turbine No. 8	NOx	0.054	0.080	Yes
	PM_{10}	0.033	0.060	Yes
Gas Turbine No. 9	NOx	0.054	0.080	Yes
	PM_{10}	0.033	0.060	Yes

In Addition, prior to access to the Priority Reserve and issuance of the permits to construct, El Segundo Power, LLC must demonstrate to the satisfaction of the Executive Officer that it has met each of the following additional requirements:

Rule 1309.1(c)(1)
El Segundo Power, LLC agrees to a permit condition requiring the facility to meet BARCT for pollutants received from the Priority Reserve for all existing sources located in the District prior to the operation of the new sources or at a schedule approved by the Executive Officer and no later than 3 years following issuance of a permit to construct for the new sources and all sources under common ownership within the District are in compliance with all applicable District rules, variances, orders, and settlement agreements.

Rule 1309.1(c)(2)
El Segundo Power, LLC pays the new mitigation fees pursuant to subdivision (g) as listed in the August 3, 2007 version of version of Rule 1309.1. In addition, AQMD Management informed El Segundo Power, LLC that they are required to pay the $92,000 mitigation rate as specified in the August 3, 2007 version of Rule 1309.1 rather than the old rate of $25,000 per pound stipulated in the previous version of the rule. EL Segundo Power, LLC will comply with this provision.

Rule 1309.1(c)(3)
El Segundo Power, LLC conducts a due diligence effort [based on an ERC cost not to exceed the applicable mitigation fee for that pollutant at the location of the electrical generating facility (EGF) and as specified if subdivision (g) of Rule 1309.1] approved by the Executive Officer to secure available ERCs for

requested Priority Reserve pollutants. Such efforts shall include securing available ERCs including those available through state emission banks or creating ERCs through SIP approved credit generation programs as available. El Segundo Power, LLC is actively seeking to secure available ERCs and has provided monthly written acknowledgement of such efforts to AQMD.

Rule 1309.1(c)(4)
El Segundo Power, LLC enters into a long-term contract (at least one year) with the State of California to sell at least 50 percent of the portion of power which it has generated using the Priority Reserve Credits and provided the Executive Officer determines at the time of permitting and based on consultations with State power agencies that the State of California is both entering into such long term contracts and that a need for such contract exists at the time of permitting, if the facility is a net generator.

Rule 1309.1(c)(5)(A)
This rule requires that the proposed purchase of credits from the Priority Reserve together with credits otherwise obtained is offset at a ratio of 1.2-to-1.0. El Segundo Power, LLC will offset all required emission increases at a ratio of 1.2-to-1.0. Therefore, El Segundo Power, LLC will comply with this subpart.

Rule 1309.1(c)(5)(B)
This rule requires El Segundo Power, LLC to demonstrate that renewable/alternative energy forms in lieu of natural gas fired EGF are not viable options for power generation at the site.

a) Hydropower is not viable at the El Segundo site due to the lack of sufficient water resources that are needed for conventional hydropower applications and due to the lack of sufficient space for needed equipment and materials.

b) Wind power is not viable at the El Segundo site for several reasons. The project site does not have sufficient wind resources necessary to generate significant power from the site. Wind resource assessments by the CEC that most sufficient wind resource areas to be inland and the mountain passes in California. Second, the site lacks sufficient space necessary for siting wind generation projects. The CEC estimates that approximately 40 acres are needed for each 1 MW of installed wind capacity, which would require over 3,000 times more space than the available 7 acres at the El Segundo site in order to provide the needed 573 MW of electrical generating capacity.

c) Wave power is not viable because El Segundo Power, LLC does not control the offshore property adjacent to the site, and furthermore, the adjacent offshore area is not a recognized wave power resource area. The CEC finds that primary and secondary wave energy resource areas in California to be located further offshore and generally north and west of the Channel Islands.

d) Geothermal power is not viable at the El Segundo site because the area does not have sufficient geothermal brine temperatures necessary for generating power. CEC does not show any known geothermal energy resources in the vicinity of the project site.

e) Fuel cell technology is not a viable option. El Segundo Power, LLC project objectives include the delivery of 573 MW of power to the SCE transmission grid. Fuel cell technology is not commercially available to meet this objective and most existing fuel cell technology as it relates to EGF applications is still cost prohibitive.

El Segundo Power, LLC has considered the possible uses of renewable/alternative energy sources as required in this rule and none of the above sources of renewable/alternative energy are feasible at the El Segundo site.

Rule 1309.1(c)(6)
El Segundo Power, LLC must agree to a permit condition requiring the new sources to be fully and legally operational at the rated capacity within three (3) years of issuance of the Permit to Construct. El Segundo Power, LLC will be required by permit condition to comply with this requirement. Compliance is expected.

Rule 1309.1(d)(6)
El Segundo Power, LLC must use any ERCs held first, before access to the Priority Reserve is allowed. El Segundo Power, LLC will consume its existing ERCs prior to accessing the Priority Reserve. Compiance is expected.

Rule 1309.1(d)(14)
El Segundo Power, LLC must enter into a long term contract with Southern California Edison Company or the San Diego Gas and Electric Company or the State of California to provide electricity in Southern California. Compliance is expected.

Rule 1401 – New Source Review of Toxic Air Contaminants
This rule specifies limits for maximum individual cancer risk (MICR), acute hazard index (HIA), chronic hazard index (HIC) and cancer burden (CB) from new permit units, relocations, or modifications to existing permits which emit toxic air contaminants. Rule 1401 requirements are summarized as follows:

Table 27 - Rule 1401 Requirements

Parameters and Specifications	Rule 1401 Requirements
MICR, without T-BACT	$\leq 1x10^{-6}$
MICR, with T-BACT	$\leq 1x10^{-5}$
Acute Hazard Index	≤ 1.0
Chronic Hazard Index	≤ 1.0
Cancer Burden	≤ 0.5

The applicant performed a Tier 4 health risk assessment using the Hot Spots Analysis and Reporting Program (HARP). The analysis included an estimate of the MICR for the nearest residential and commercial receptors, as well as the acute and chronic hazard indices on a per unit basis. Table 28 below shows the results of the health risk assessment as performed by the applicant.

Table 28 - Rule 1401 Modeled Results (permit-unit basis)

Risk Parameter	Residential	Commercial	Rule 1401 Requirements	Compliance (Yes/No)
CTG No. 8				
MICR	4.00EE-8	1.28EE-8	≤1.0EE-6	Yes
HIA	1.53EE-2	1.53EE-2	≤1.0	Yes
HIC	2.42EE-3	4.02EE-3	≤1.0	Yes
CTG No. 9				
MICR	4.05EE-8	1.31EE-8	≤1.0EE-6	Yes
HIA	1.54EE-2	1.54EE-2	≤1.0	Yes
HIC	2.45EE-3	4.13EE-3	≤1.0	Yes

Table 28 shows that El Segundo Power, LLC will comply with the applicable requirements of Rule 1401. The cancer burden is not computed because the highest MICR is less than $1EE10^{-6}$. AQMD modeling staff has reviewed the health risk assessment for the proposed project and provided their comments in a memorandum from Ms. Jill Whynot to Mr. Mike Mills dated November 15, 2007. The ISCST3 modeling conforms to AQMD's dispersion modeling procedures. No discrepancies were noted.

Rule 2005(g) – Additional Requirements

As with Rule 1303(b)(5) for the Non-RECLAIM pollutants, El Segundo Power, LLC has addressed the alternative analysis, statewide compliance, protection of visibility, and CEQA compliance requirements of this rule for NOx. These requirements are summarized below.

Rule 2005(g)(1) – Statewide Compliance

El Segundo Power, LLC has submitted a letter to the AQMD dated June 13, 2007 (see file) stating that any and all facilities that El Segundo Power, LLC owns or operates in the State of California (including the proposed re-powering project) are in compliance or are on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act. Therefore, compliance is expected.

Rule 2005(g)(2) – Alternative Analysis

Requires the applicant to conduct an analysis of alternative sites, sizes, production processes, environmental control techniques for the re-powering project and to demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with this project. El Segundo Power, LLC is exempt from this requirement per Rule 2005(g)(3)(B).

Rule 2005(g)(3) – Compliance through CEQA

The California Energy Commission (CEC) is the lead agency for this project and will be conducting their CEQA analysis with input from interested parties/agencies. As part of the CEQA analysis, CEC will be issuing an amendment to their decision dated February 2005. Compliance is expected

Rule 2005(g)(4) – Protection of Visibility
Modeling is required if the source is within a Federal Class I area and the NO_x potential to emit (PTE) exceeds 40 TPY. Since the nearest Federal Class I area is located well beyond the project site, modeling for plume visibility is not required for this project.

Rule 2005(h) – Public Notice
El Segundo Power, LLC will comply with the requirements for Public Notice found in Rule 212. Therefore compliance with Rule 2005(h) is expected.

Rule 2005(i) – Rule 1401 Compliance
El Segundo Power, LLC will comply with Rule 1401 as demonstrated in the Tier 4 analysis and subsequently reviewed and found to be satisfactory by AQMD modeling staff. Compliance is expected.

Rule 2005(j) – Compliance with State and Federal NSR.
El Segundo Power, LLC will comply with the provisions of this rule by having demonstrated compliance with AQMD NSR Regulations XIII (non-RECLAIM) and Rule 2005-(RECLAIM).

REGULATION XVII-Prevention of Significant Deterioration
On July 25, 2007 AQMD and EPA have signed a new Partial PSD Delegation Agreement intended to delegate the authority and responsibility to AQMD for issuance of initial PSD permits and for PSD permit modifications where the applicant does not seek to use the emissions calculation methodologies promulgated in 40 CFR 52.21 (NSR Reform) but not set forth in AQMD Regulation XVII. The Partial Delegation agreement also does not delegate authority and responsibility to AQMD to issue new or modified PSD permits based on Plant-wide Applicability Limits (PALS) provisions of 40 CFR 52.21. Therefore, consistent with the Partial Delegation Agreement, for all new and modified PSD permits, AQMD will only use Regulation XVII as the bases for the PSD analysis.

The South Coast Basin where the project is to be located is in attainment for NOx, SO_2, and CO emissions. Therefore PSD applies to these pollutants. For combined cycle projects, a significant emission increase is 40 tpy or more of NOx or SO_2 or 100 tons per year or more of CO. Table 29 below shows the net emissions at the El Segundo facility due to the addition of the two proposed Siemens rapid response combined cycle CTGs and the removal of steam boiler units 1 & 2.

Table 29 - Net Emissions from El Segundo Power, LLC

	NOx lb/day	SOx lb/day	CO lb/day
Two (2) Siemens combined cycle CTGs	+91.0	+7.4	+194.1
Removal of Boiler Units 1 & 2	-396.2	-1.8	-223.2
Net Emissions	-305.2	-5.6	-29.1
PSD Significance Thresholds	+40	+40	+100
PSD Analysis Required	No	No	No

Table 29 above shows that the El Segundo Power combined cycle project will not result in a significant increase of NOx, SO_2, or CO. Therefore, a PSD review is not required.

Rule 1703(a)(2) requires each permit unit be constructed using BACT for each attainment air contaminant for which there is a net emission increase. The BACT requirements for CO as well as the applicant's

BACT proposals for the CTGs are listed in Table 30 below: As shown below, the equipment will comply with PSD BACT requirements for major sources.

Table 30 – CO BACT Proposals for the Siemens Combined Cycle CTGs

Pollutant	AQMD BACT Requirements	Proposed BACT	Comply (Yes/No)
CO	2.0 ppmvd at 15% O2, 1-hour rolling average	2.0 ppmvd at 15% O2, 1-hour rolling average	Yes
NOx	2.0 ppmvd at 15% O2, 1-hour rolling average	2.0 ppmvd at 15% O2, 1-hour rolling average	Yes
SOx	PUC quality natural gas w/ S content ≤ 1 grain/100 scf	PUC quality natural gas w/ S content = 0.25 grain/100 scf	Yes

INTERIM PERIOD EMISSION FACTORS – Rule 2012

RECLAIM requires that a NO_x emission factor be used for reporting emissions during the interim reporting period. The interim period is defined as a period typically 12 months in duration, when the CEMS has not been certified. During this period, the emissions cannot be accurately or officially quantified, monitored, or verified. The emissions during this period are assumed to be at uncontrolled levels. The interim reporting period can be broken down into the two parts which includes (a) the commissioning period in which an uncontrolled[6] emission rate is assumed, and (b) the remaining period at which controlled rates at BACT are assumed. Since El Segundo Power, LLC will be included in NO_x RECLAIM, an interim period emission factor for NO_x will be determined. Although not a RECLAIM pollutant, a CO emission factor will also be calculated so that the applicant may use it to report emissions during the interim period when the CEMS is not yet certified for CO. In the event CEMS data is not available, NO_x, and CO emissions during the interim period will be calculated using monthly fuel usage and the emission factors derived below. There will be two interim period emission factors calculated for NO_x and two interim period emission factors calculated for CO. The first factor will be for use during commissioning stage when the CTGs are assumed to be operating at uncontrolled levels and the second factor will be for use after commissioning is complete and the CTGs are assumed to operate at BACT levels. The specific calculations are shown in Appendix G and the results are shown in the tables below, and are done on a per turbine basis.

Commissioning Period

Pollutants	NOx	CO
Total emissions (lbs)	12,478	130,337
Total Fuel (mmscf)	754	754
Emission Factor (lb/mmscf)	**16.55**	**172.89**

Remaining Period (Non-Commissioning)

Pollutants	NOx	CO
Total emissions (lbs)	96,371	175,246
Total Fuel (mmscf)	11,124	11,124
Emission Factor (lb/mmscf)	**8.66**	**15.75**

[6] The emission factor for the commissioning period is an average for the entire 415 hour commissioning period. During this period, the turbines may be uncontrolled, partially controlled, or 100% controlled.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)
The California Energy Commission (CEC) is the lead agency for the El Segundo Power Redevelopment Project (00-AFC-14C), and will be addressing CEQA compliance. It is anticipated that the CEC will amend its decision dated February 2005 to address the proposed changes to the El Segundo Power Redevelopment Project.

40CFR Part 60 Subpart GG – NSPS for Stationary Gas Turbines
The refurbished CTGs proposed for construction at El Segundo Power, LLC are subject to the requirements of 40CFR60 Subpart KKKK, and are exempt from 40CFR60 Subpart GG per 40 CFR60 Subpart KKKK, §60.4305 (b).

40CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
Subpart KKKK establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines with a heat input greater than 10 MMBTU/hr (10.7 gigajoules per hour), based on higher heating value, which commenced construction, modification or reconstruction after February 18, 2005.

§60.4320(a) Both CTGs are natural gas-fired and has a heat input > 850 MMBTU/hr, therefore, it is subject to a NO_X emission limit of 15 ppmv @ 15% O_2 from Table 1 of this subpart. The turbine is required to comply with BACT for NO_x which is officially at 2.0 ppmv at 15% O2, dry basis for a combined cycle plant. It is anticipated that the CTGs will meet a NO_x level of 2.0 ppmv or less at 15% O2 on a 1-hour average which is more stringent than this subpart. Therefore, compliance with this section is expected.

§60.4330(a)(2) Natural gas fuel burned in the turbine has a sulfur content of 0.0006 lb-SO_2/MMBtu, which is less than 0.06 lb-SO_2/MMBTU (26 ng-SO_2/J) required by this section. Therefore, compliance with the sulfur dioxide limits of this section is expected.

§60.4335 The gas turbines use water injection to help reduce NO_X to compliance levels. Monitoring is required and will be accomplished with a CEMS; therefore, compliance with this section is expected with a certified CEMS.

§60.4345 The CEMS is required to be certified according to the Performance Specification 2 (PS 2) in appendix B to this part. SCE will be required to file a CEMS application package with Source Test Engineering to certify the CEMS to meet the requirements of Rule 218 or 40CFR60 Appendix B. Therefore, compliance with this section is expected.

§60.4400(a) An initial source test will be required per §60.8. The annual source testing requirement for NOx will be satisfied through the annual RATAs performed on the CEMS. Compliance with the source testing requirements is expected.

40CFR Part 72 – Acid Rain Provisions
El Segundo Power, LLC is subject to the requirements of the federal Acid Rain program because the electricity generated will be rated at greater than 25 MW. This program is similar to RECLAIM in that facilities are required to cover SO_2 emissions with SO_2 allowances that are similar in concept to RTC's.

SO_2 allowances are however, not required in any year when the unit emits less than 1,000 lbs of SO_2. Facilities with insufficient allowances are required to purchase SO_2 credits on the open market. In addition, both NOx and SO_2 emissions will be monitored and reported directly to USEPA. Based on the above, compliance with this rule is expected.

REGULATION XXX – Title V

El Segundo Power, LLC is a Title V facility because the cumulative emissions will exceed the Title V major source thresholds and because it is also subject to the federal acid rain provisions. The Title V significant revision will be processed and the required public notice will be sent along with the Rule 212(g) Public Notice, which is also required for this project. EPA is afforded the opportunity to review and comment on the project within a 45-day review period.

OVERALL EVALUATION / RECOMMENDATION(S)

Issue a Facility Permit to Construct with the following permit conditions.

PERMIT CONDITIONS

CTGs

A63.2 The operator shall limit emission from this equipment as follows:

CONTAMINANT	EMISSION LIMIT
PM_{10}	6,935 LBS IN ANY ONE MONTH
SOx	1,065 LBS IN ANY ONE MONTH
VOC	4,930 LBS IN ANY ONE MONTH

The operator shall calculate the monthly emissions for VOC, PM10 and SOx using the equation below and the following emission factors: VOC: 2.93 lb/mmcf; PM10: 4.66 lb/mmcf; and SOx: 0.72 lb/mmcf.

Monthly Emissions, lb/mon = X (E.F.)

Where X = monthly fuel usage, mmscf/month and E.F. = emission factor indicated above.

[Rule 1303-Offsets]

A99.7 The 2.0 PPM NOx emission limits shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 415 hours. Start-up time shall not exceed 60 minutes for each start-up. Shutdown periods shall not exceed 60 minutes for each shutdown. The turbine shall be limited to a maximum of 200 start-ups per year. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.

[Rule 2005, Rule 1703(a)(2) - PSD-BACT]

A99.8 The 2.0 PPM CO emission limits shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 415 hours. Start-up time shall not exceed 60 minutes for each start-up. Shutdown periods shall not exceed 60 minutes for each shutdown. The turbine shall be limited to a maximum of 200 start-ups per year. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.

[Rule 1703 - PSD, Rule 1703(a)(2) - PSD-BACT]

A99.9 The 2.0 PPM VOC emission limit shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 415 hours. Start-up time shall not exceed 60 minutes for each start-up. Shutdown periods shall not exceed 60 minutes for each shutdown. The turbine shall be limited to a maximum of 100 start-ups per year. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.
[Rule 1303 - BACT]

A99.10 The 16.55 LBS/MMCF NOx emission limit shall only apply during the interim reporting period during initial turbine commissioning to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from entry into RECLAIM.
[Rule 2012 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen Emissions]

A99.11 The 8.66 LBS/MMCF NOx emission limits shall only apply during the interim reporting period after initial turbine commissioning to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from entry into RECLAIM.
[Rule 2012 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen Emissions]

A195.8 The 2.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1703(a)(2) - PSD-BACT]

A195.9 The 2.0 PPMV NOX emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1703(a)(2) - PSD-BACT, Rule 2005]

A195.10 The 2.0 ppmv VOC emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1303(a) - BACT]

A327.1 For the purpose of determining compliance with District Rule 475, combustion contaminants emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.
[Rule 475]

A433.1 The operator shall comply at all times with the 2.0 ppm 1-hour BACT limit for NOx, except as defined in condition A99.1 and for the following scenario:

Operating Scenario	Maximum Hourly Emission Limit	Operational Limit
Start-up	112 lb/hr	NOx emissions not to exceed 112 lbs total per start-up per turbine. Each turbine shall be limited to 100 start-ups per year, with each start-up not to exceed 60 minutes.

[Rule 1703(a)(2)-PSD-BACT, Rule 2005]

B61.2 The operator shall not use natural gas containing the following specified compounds:

Compound	Grains per 100 scf
H2S	0.25

This concentration limit is an annual average based on monthly samples of natural gas composition or gas supplier documentation. The gaseous fuel sample shall be tested using District method 307-91 for total sulfur calculated as H2S.
[Rule 1303(b) - Offset]

C1.6 The operator shall limit the fuel usage to no more than 1,500 mmcsf in any one calendar month.

For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single turbine.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition.
[Rule 1303(b)(2) - Offset]

D12.10 The operator shall install and maintain a(n) flow meter to accurately indicate the fuel usage being supplied to the turbine.

The operator shall also install and maintain a device to continuously record the parameter being measured
[Rule 1303(b)(2) - Offset, Rule 2012]

D29.7 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District Method 100.1	1 hour	Outlet of the SCR
CO emissions	District Method 100.1	1 hour	Outlet of the SCR
SOX emissions	AQMD Method 307-91	Not Applicable	Fuel Sample
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR
PM10 emissions	District Method 5	4 hours	Outlet of the SCR
NH3 emissions	District Method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR

The test shall be conducted after AQMD approval of the source test protocol, but no later than 180 days after initial start-up. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, and the turbine generating output in MW.

The test shall be conducted in accordance with AQMD approved test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the AQMD before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted when this equipment is operating at maximum, average, and minimum loads.

The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit.

For natural gas fired turbines only, VOC compliance shall be demonstrated as follows: a) Stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of canisters are done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) Analysis of canisters are per EPA Method TO-12 (with pre concentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F.

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval except for the determination of compliance with the VOC BACT level of 2.0 ppmv limit calculated as carbon for natural gas fired turbines.

Because the VOC BACT level was set using data derived from various source test results, this alternate VOC compliance method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results shall be reported with two significant digits.

For the purpose of this condition, alternative test methods may be allowed for each of the above pollutants upon concurrence of AQMD and EPA.

[Rule 1303(a)(1) - BACT, Rule 1703(a)(2) - PSD-BACT, Rule 1303(b)(2) - Offset, Rule 2005,]

D29.8 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR

The test shall be conducted and the results submitted to the District within 45 days after the test date. The AQMD shall be notified of the date and time of the test at least 7 days prior to the test.

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration limit

If the equipment is not operated in any given quarter, the operator may elect to defer the required testing to a quarter in which the equipment is operated.
[Rule 1303(a)(1) - BACT]

D29.9 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
SOX emissions	AQMD Method 307-91	Not Applicable	Fuel Sample
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR
PM10 emissions	District Method 5	4 hours	Outlet of the SCR

The test shall be conducted at least once every three years for SOx and PM10, and yearly for VOC.
The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, and the turbine generating output in MW.

The test shall be conducted in accordance with AQMD approved test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the AQMD before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted when this equipment is operating at 100 percent load.

The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit.

For natural gas fired turbines only, VOC compliance shall be demonstrated as follows: a) Stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of canisters are done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) Analysis of canisters are per EPA Method TO-12 (with pre concentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F.

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval except for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines.

Because the VOC BACT level was set using data derived from various source test results, this alternate VOC compliance method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results shall be reported with two significant digits.

For the purpose of this condition, alternative test methods may be allowed for each of the above pollutants upon concurrence of AQMD and EPA.

[Rule 1303(a)(1) - BACT, Rule 1303(b)(2) - Offset, Rule 1703(a)(2) - PSD-BACT]

D29.10 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NOx	District Method 100.1	1 hour	Outlet of the SCR
PM10	District Method 5	4 hours	Outlet of the SCR

The test shall be conducted after District approval of the source test protocol, but no later than 180 days after initial start-up. District shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted at full load to demonstrate compliance with the 0.080 lb/MW-hr NOx and 0.060 lb/MW-hr PM10 requirements set forth in Rule 1309.1. If the actual measurement is within the accuracy of the devices used for electrical power measurement, the result will be acceptable.

The lb/MW-hr emission rate of each electrical generating unit shall be determined by dividing (a) the lb/hr emission rate measured at the location and in accordance with the test method specified above, by (b) the adjusted gross electrical output of each electrical generating unit.

The adjusted gross electrical output of each electrical generating unit shall be determined by making the following adjustments to the measured gross electrical output:

> Apply the manufacturer's standard correction factors to calculate gross electrical output at ISO conditions.

The test shall be conducted in accordance with District approved test protocol. The protocol shall be submitted to the District engineer no later than 45 days before the proposed test date and shall be approved by the District before the test commences.

The test protocol shall include the proposed operating conditions of the electrical generating unit during the test, the correction and degradation factors and documentation of their validity, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

For the purpose of this condition, alternative test methods may be allowed for each of the above pollutants upon concurrence of AQMD and EPA.

[Rule 1309.1]

D82.4 The operator shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv
Concentrations shall be corrected to 15 percent oxygen on a dry basis
The CEMS shall be installed and operated no later than 90 days after initial start-up of the turbine, and in accordance with an approved AQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from AQMD. Within two weeks of the turbine start-up, the

operator shall provide written notification to the District of the exact date of start-up.

The CEMS shall be installed and operated to measure CO concentrations over a 15 minute averaging time period.

The CEMS would convert the actual CO concentrations to mass emission rates (lbs/hr) using the equation below and record the hourly emission rates on a continuous basis.

CO Emission Rate, lbs/hr = K Cco Fd[20.9/(20.9% - %O2 d)][(Qg * HHV)/106], where

K = 7.267 *10^{-8} (lb/scf)/ppm

Cco = Average of four consecutive 15 min. ave. CO concentration, ppm

Fd = 8710 dscf/MMBTU natural gas

%O_2 d = Hourly ave. % by vol. O_2 dry, corresponding to Cco

Qg = Fuel gas usage during the hour, scf/hr

HHV = Gross high heating value of fuel gas, BTU/scf
[Rule 1703(a)(2) - PSD-BACT]

D82.5 The operator shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis.
The CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine and shall comply with the requirements of Rule 2012. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2)and 2012(h)(3). Within two weeks of the turbine start-up date, the operator shall provide written notification to the District of the exact date of start-up.

The CEMS shall be installed and operating (for BACT purposes only) no later than 90 days after initial start up of the turbine.
[Rule 1703(a)(2) - PSD-BACT, Rule 2005, Rule 2012]

E193.2 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 00-AFC-14C project.
[CEQA]

E193.3 The operator shall operate and maintain this equipment according to the following requirements:

Devices D67 and D68 shall be fully and legally operational within three years of issuance of the Permit to Construct
[Rule 1309.1]

I296.2 This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emission increase.

To comply with this condition, the operator shall prior to the 1st compliance year hold a minimum NOx RTCs of 104,864 lbs/yr. This condition shall apply during the 1st months of operation, commencing with the initial operation of the gas turbine.

To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the 1st compliance year, hold a minimum of lbs/yr of 90,953 NOx RTC's for operation of the gas turbine. In accordance with Rule 2005(f), unused RTC's may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the 1st compliance year.
This condition shall apply to each turbine individually.
[Rule 2005]

K40.4 The operator shall provide to the District a source test report in accordance with the following specifications:

Source test results shall be submitted to the District no later than 60 days after the source test was conducted.
Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lb/hr), and lb/MMCF. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains/DSCF.
All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute.
All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.
Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.
[Rule 1303(a)(1) - BACT, Rule 1303(b)(2) - Offset, Rule 1703(a)(2) - PSD-BACT, Rule 2005]

K67.5 The operator shall keep records in a manner approved by the District, for the following parameter(s) or item(s):

Natural gas fuel use after CEMS certification
Natural gas fuel use during the commissioning period
Natural gas fuel use after the commissioning period and prior to CEMS certification
[Rule 2012]

(SCR/CO Catalyst)

A195.11 The 5 ppmv NH3 emission limit is averaged over 60 minutes at 15% O2, dry basis. The operator shall calculate and continuously record the NH3 slip concentration using the following:

NH3 (ppmv) = [a-b*c/1EE+06]*1EE+06/b

where,
a = NH3 injection rate (lbs/hr)/17(lb/lb-mol)
b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol)
c = change in measured NOx across the SCR (ppmvd at 15% O2)

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months.
The NOx analyzer shall be installed and operated within 90 days of initial start-up.
The operator shall use the above described method or another alternative method approved by the Executive Officer.
The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information without corroborative data using an approved reference method for the determination of ammonia.
[Rule 1303(a)(1) - BACT, Rule 2012]

D12.11 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

The operator shall also install and maintain a device to continuously record the parameter being measured.
The measuring device or gauge shall be accurate to within plus or minus 5 percent.
It shall be calibrated once every twelve months.
The ammonia injection rate shall remain between 13.5 and 16.5 gallons per hour.

[Rule 1303(a)(1) - BACT, Rule 1703(a)(2) - PSD-BACT, Rule 2005]

D12.12 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the parameter being measured.
The measuring device or gauge shall be accurate to within plus or minus 5 percent.
It shall be calibrated once every twelve months.
The temperature shall remain between 450 degrees F and 750 degrees F
The catalyst temperature shall not exceed 750 degrees F during the start-up period.

[Rule 1303(a)(1) - BACT, Rule 1703(a)(2)- PSD-BACT, Rule 2005]

D12.13 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

The operator shall also install and maintain a device to continuously record the parameter being measured.
The measuring device or gauge shall be accurate to within plus or minus 5 percent.
It shall be calibrated once every twelve months.
The pressure drop across the catalyst shall remain between 5 inches of water column and 7.6 inches of water column.
The pressure drop across the catalyst shall not exceed 7.6 inches of water column during the start-up period.

[Rule 1303(a)(1) - BACT, Rule 1703(a)(2) - PSD-BACT, Rule 2005]

E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 00-AFC-14C project.
[CEQA]

E179.5 For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

Condition Number D12.2
Condition Number D12.3
[Rule 1303(a)(1) - BACT, Rule 1703(a)(2) - PSD-BACT]

E179.6 For the purpose of the following condition numbers, continuously record shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month.

Condition Number: D12.4
[Rule 1303(a)(1) - BACT, Rule 1703(a)(2) - PSD-BACT]

(Ammonia Storage Tank)

C157.1 The operator shall install and maintain a pressure relief valve with a minimum pressure set at 50 psig.
[Rule 1303(a)(1) - BACT]

E144.2 The operator shall vent this equipment, during filling, only to the vessel from which it is being filled.
[Rule 1303(a)(1) - BACT]

E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 00-AFC-14C project.
[CEQA]

EL SEGUNDO POWER REDEVELOPMENT PROJECT
List of Appendices

1. Appendix A - Siemens SGT6-5000F CTG Hourly Emissions
2. Appendix B - Siemens SGT6-5000F CTG Monthly Emissions
   - Commissioning year
   - Non-Commissioning year
   - 30-Day Averages (Commissioning year)
   - 30-Day Averages (Non-commissioning year)
3. Appendix C - Siemens SGT6-5000F CTG Annual Emissions
   - Commissioning year
   - Non-commissioning year
4. Appendix D - First Year NOx RTC Calculations
5. Appendix E - Subsequent Year NOx RTC Calculations
6. Appendix F - Interim Period Emission Factors
7. Commissioning Schedules
8. Performance Runs