DOCKETED

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Project Title:	Sunrise Cogeneration Power Project (Compliance)
TN #:	237495
Document Title:	Sunrise Power Improvement Project
Description:	Petition to Amend License
Filer:	Scott Seipel
Organization:	NRG, Inc.
Submitter Role:	Applicant
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Sunrise Power Company, LLC

April 12, 2021

Mr. Eric Veerkamp
Compliance Project Manager
Sunrise Power Company (98-AFC-04C)
California Energy Commission
1516 Ninth Street (MS-2000)
Sacramento, CA 95814-5512

Re: Sunrise Power Company, LLC Petition to Amend Application, California Energy Commission Docket No. 98-AFC-04C

Dear Mr. Veerkamp:

Sunrise Power Company, LLC (Sunrise) submits the attached petition to amend the California Energy Commission License Docket No. 98-AFC-04C for the Sunrise Power Project located at 12857 Sunrise Power Road, Fellows, California. The Project improvements include the replacement of a section of the gas turbine with improved technology, improved combustion system, and an upgraded control system for the turbine generators. These improvements will increase the power output and improve efficiency. Sunrise submitted an application to the San Joaquin Air Pollution Control District to amend the Title V Air Permit and the Permit to Operate on October 28, 2020. A copy of the application is provided herein.

Petition filing fees in the amount of $5,000.00 will be submitted in compliance with California Public Resource Code Section 25806 (amended in 2015) via overnight mail.

Certification
I declare, under penalty of perjury under the laws of the state of California, that, based on information and belief formed after reasonable inquiry, all information provided in this reporting package is true, accurate, and addresses all deviations during this reporting period.

If you have any questions regarding this matter or require further data, please contact David King at (661) 768-5006 or Scott Seipel at (909) 648-5008.

Best Regards,

David S. King
Plant Manager

Attachment
cc: L. Yannayon (Attn: AIR-5)
E. Veerkamp – CEC

bxc: D. S. King - Sunrise (w/attachments)
M. Baker – Sunrise (w/attachments)
G. Piantka – NRG (w/attachments)
C. S. Seipel – NRG (w/attachments)

Sunrise Power Company – CEC Post Certification Petition to Amend – California Energy Commission (CEC) 12857 Sunrise Power Rd. Fellows, California

Power Improvement Project

April 2021

Project No.: 0563488

Sunrise Power Company

The business of sustainability

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1. OVERVIEW OF THE PETITION

Sunrise Power Company, LLC (Sunrise - Petitioner), the Project Owner, a wholly owned subsidiary of NRG Energy, Inc., proposes to make modifications to equipment licensed by the California Energy Commission (CEC) for the Sunrise Power Project (CEC Docket No. 98-AFC-4C), located at 12857 Sunrise Power Rd., Fellows, California.

The Sunrise facility is a 585-megawatt (MW) nominally rated 2x1 combined cycle power facility consisting of the following major components:

- Two 160 MW (Nominal) General Electric Frame 7FA, Natural Gas-Fired Combustion Turbine Generators (CTG1 and CTG2) Equipped with Dry Low NOx (DLN) Combustors
- Two Heat Recovery Steam Generators with Duct Firing
- One Steam Turbine Generator
- Selective Catalytic Reduction (SCR) and Oxidation Catalyst for CTG1 and CTG2

The facility is located within the jurisdiction of the San Joaquin Valley Air Pollution Control District (SJVAPCD) and has a Title V Operating Permit. The SJVAPCD Identification Number is S-3746. The permit consists of four permitted units at the site, including the two combined-cycle power generating units, a 137,000-gallon per minute cooling tower, and a portable diesel fuel-fired engine driving an electrical generator. The portable diesel fuel-fired engine electrical generator intended for maintaining and preserving critical equipment during loss of grid power has not been installed or utilized to date. This equipment is maintained in the permit for contingency. The SJVAPCD Title V permit has conditions limiting the mass emissions of volatile organic compounds (VOC), oxides of nitrogen (NOx), carbon monoxide (CO), sulfur oxides (SOx), particulate matter 10 micrometers in diameter and smaller (PM_{10}/$PM_{2.5}$) and ammonia (NH_3) on an hourly, daily, and annual basis. Separate provisions apply to startup and shutdowns. The permits also have conditions limiting the concentration of NOx, VOC, CO and NH_3 to 2.0 parts per million by volume on a dry basis of 15 percent oxygen (ppmvd @ 15% O_2), 2.0 ppmvd @ 15% O_2, 4 ppmvd @ 15% O_2 and 10 ppmvd @ 15% O_2, respectively. The NOx ppmvd and pound per hour (lb/hr) limits are averaged over a 1-hour rolling period excluding startup and shutdown. The CO, PM, SOx, VOC ppmvd, and lb/hr limits are based on a 3-hour rolling average. The ammonia slip limit is based on a 24-hour average. The concentration limits do not apply during startup or shutdown.

Sunrise is submitting this Petition to Amend (Petition) to make facility improvements that include the installation of a new hot gas path (turbine section and combustion system) and control system to the CTGs. These improvements will increase the power output and improve efficiency. Although the proposed project will increase output, increase some hourly and daily pollutant mass emissions and increase the maximum hourly fuel consumption, this project will not result in an increase in annual emissions above existing permitted limits. In addition, Sunrise will maintain pollutant concentration limits that are in the existing permits (Permit # S-3746-1-12 and S-3746-2-12). Additional details on the proposed Project are included in Section 2.1 of this Petition.

1.1 INFORMATION REQUIREMENTS FOR THE POST-CERTIFICATION AMENDMENT

This Petition contains the information required under the CEC's Siting Regulations for post-certification project modifications (California Code of Regulations [CCR] Title 20, Section 1769). This Petition, as summarized in Table 1 below, contains the information necessary for staff to determine that that the Project will not (a) significantly affect the environment, (b) cause a change or deletion of a condition of certification (COC), or (c) cause the project not to comply with applicable laws, ordinances, regulations, and standards (LORS).

Table 1: Informational Requirements for Post-Certification Modifications

CCR Title 20, Section 1769 Requirement	Section of Petition Fulfilling Requirement
Complete description of the proposed modifications, including new language for any conditions that will be affected. Section 1769(a)(1)(A).	2.1 Proposed Facility Modifications 2.2 Proposed Changes to the Conditions of Certification
A discussion of the necessity for the proposed modification. Section 1769(a)(1)(B).	2.3 Necessity of Proposed Modifications
If the modification is based on information that was known by the petitioner during the certification proceeding, an explanation of why the issue was not raised at that time. Section 1769(a)(1)(C).	2.4 Proposed Modifications Are Based Upon Information Previously Unknown to Petitioner
If the modification is based on new information that changes or undermines the assumptions, rationale, findings, or other bases of the final decision, an explanation of why the change should be permitted. Section 1769(a)(1)(D).	2.5 Proposed Modifications Are Based on New Information that Changes or Undermines the Assumptions, Rationale, Findings, or Other Bases of the Final Decision
An analysis of the impacts the modification may have on the environment and proposed measures to mitigate any significant adverse impacts. Section 1769(a)(1)(E).	2.6 Analysis of the Environmental Impacts from the Proposed Modifications
A discussion of the impact of the modification on the facility's ability to comply with applicable laws, ordinances, regulations, and standards. Section 1769(a)(1)(F).	2.7 Impacts of the Modifications on the Facility's Ability to Comply with Applicable LORS
A discussion of how the modification affects the public. Section 1769(a)(1)(G).	2.8 Impacts of the Modifications to the Public
A list of property owners potentially affected by the modification and a discussion on the potential effect on property owners, the public, and the parties to the application proceeding. Section 1769(a)(1)(H) and Section 1769(a)(1)(I).	2.9 Potential Effect on Nearby Property Owners, the Public, and the Parties in the Application Proceeding

2. PROJECT DESCRIPTION

2.1 PROPOSED FACILITY MODIFICATIONS

Sunrise plans to make improvements to the existing system. Sunrise is proposing to install enhanced hardware to the combustor and turbine sections of CTG1 and CTG2, and optimize the control logic of the gas turbines. This project is referred to as Sunrise Power Improvement (the Project). The proposed performance upgrades include a new combustion system with higher gas turbine firing temperatures and a new turbine section resulting in increased MW output and improved efficiency made possible by improved cooling, sealing enhancements, and advanced materials. The new DLN combustion system will achieve a NOx concentration of 9.0 ppmvd @ 15% O_2 compared to the current Original Equipment Manufacturer (OEM) guarantee of 15 ppmvd @ 15% O_2. These emission concentrations are prior to the SCR.

The performance upgrades are augmented by the addition of an upgraded General Electric Mark VIe turbine control system incorporating advanced combustion optimization capabilities, which also provides enhanced operational flexibility. The overall goal of the Project is to increase the output and efficiency of each turbine so as to improve the overall performance of the Sunrise combined cycle facility without a change in permitted emissions. The proposed modifications will increase maximum net output at the interconnection point from approximately 585 MW to 635 MW nominal at an ambient temperature of 30 degrees Fahrenheit (ºF) with a corresponding 3 to 4% improvement in efficiency (i.e., generation output per unit of fuel input). The output increase is provided as an estimate from model projections. The actual change will depend on ambient conditions. The Sunrise facility will continue to comply with the annual emission limits in the SJVAPCD (District) Permits to Operate. There are calculated increases in the maximum hourly emissions because of increased fuel consumption combined with default emission factors and permit concentration limits.

The upgraded CTGs will require a period of commissioning. The commissioning period is expected to be about 80 hours for each CTG. In addition, there may be 6 months between commissioning of the two CTGs. The commissioning is expected to occur in three phases. The first phase will be “break-in” and should take about 24 hours. The next phase is tuning and is expected to require another 24 hours. The remainder of the commissioning time will be for testing. Sunrise expects testing will be at normal operation but may include a number of stops and starts and/or load adjustments.

2.2 PREVENTION OF SIGNIFICANT DETERIORATION AND TITLE V GREENHOUSE GAS TAILORING RULE APPLICABILITY

SJVAPCD Rule 2410 references the applicable version of 40 Code of Federal Regulations (CFR) 52.21 - Prevention of Significant Deterioration (PSD) of Air Quality, June 16, 2011 version. This rule set thresholds for greenhouse gas (GHG) emissions that define when GHG emissions are covered under the PSD and Title V Operating Permit programs for new and existing industrial facilities. According to 40 CFR 52.21, beginning January 2, 2011, the pollutant GHGs are subject to regulation if:

(a) The stationary source is a new major stationary source for a regulated New Source Review (NSR) pollutant that is not a GHG, and also will emit or will have the potential to emit 75,000 tons per year (tpy) carbon dioxide equivalent (CO_2e) or more; or

(b) The stationary source is an existing major stationary source for a regulated NSR pollutant that is not a GHG, and also will have an emissions increase of a regulated NSR pollutant and an emissions increase of 75,000 tpy CO_2e or more; and

Beginning July 1, 2011, in addition to the above provisions, the pollutant GHGs shall also be subject to regulation:

(a) At a new stationary source that will emit or have the potential to emit 100,000 tpy CO_2e; or

(b) At an existing stationary source that emits or has the potential to emit 100,000 tpy CO_2e when such stationary source undertakes a physical change or change in the method of operation that will result in an emissions increase of 75,000 tpy CO_2e or more.

The proposed project does not result in a GHG emissions increase above the PSD GHG thresholds. Sunrise completed a worst case GHG estimate. The maximum fuel flow at 30°F for pre-uprate and post-uprate was used for all hours of operation. Sunrise used a pre-uprate potential hours of operation of 7,537 as reported in the 2001 permit application. The post-uprate potential hours of operation is 7,313 as presented in the SJVACPD Authority to Construct application. The calculated increase in GHG emission is less than 24,000 metric tons per year or 26,000 tons per year.

Therefore, the proposed project is not subject to PSD for GHGs. In addition, the proposed project improves the thermal efficiency of the existing turbines and this is considered a GHG Best Available Control Technology (BACT).

2.3 SJVAPCD NEW SOURCE REVIEW EVALUATION

Sunrise is conducting an NSR evaluation in accordance with SJVAPCD Rule 2201. The Authority to Construct application was submitted to SJVAPCD on October 26, 2020. The complete application is included in Appendix A. BACT requirements apply for each air contaminant when the increase is greater than 2 pounds per day. The proposed project is not expected to increase any air contaminant emission rate by 2 pounds per day or more and therefore would not require a BACT analysis. The current facility is already equipped with control devices for NOx, CO, and VOC that represent BACT.

The proposed project will not result in an annual emissions increase above the permitted limits. Sunrise will continue to comply with the current annual emission limits for NOx, CO, PM_{10}, VOC, and SOx. Consequently, emission offsets are not expected to be required.

From the comparison of Sunrise's potential to emit (i.e., existing permit limits) and the future projected potential to emit post-improvement project, the proposed project would not be a Federal Major Modification or a SB288 major modification. SJVAPCD issued its preliminary review of the Sunrise Improvement Project air permit modification / Authority to Construct application on November 17, 2020 and concluded that the application is incomplete. Additional analysis following its calculation procedures is required to determine whether the Improvement Project is subject to the Rule 2201 provisions of SB288 Major Modifications and Federal Major Modifications. A copy of the Notice of Incomplete Application is included as Appendix B in this Petition to Amend.

SJVAPCD has requested Sunrise to: (1) provide Actual Emissions for each gas turbine on a monthly basis for the 5 years prior to the Authority to Construct application for the purposes of estimating the Baseline Actual Emissions (BAE); and (2) estimate the Projected Actual Emissions (PAE) for each gas turbine as defined in its policy, APR 1150, titled "Implementation of Rule 2201 for SB288 Major Modification and Federal Major Modifications." Prior 5-year operating history is necessary for determining baseline emissions for steam electricity generating facilities like Sunrise, as opposed to the prior 10-year operating history as referenced in the November 17, 2020 letter. Sunrise calculated the BAE, PAE and unused baseline capacity, which is also considered in the comparison of pre-project baseline emissions to post-project projected emissions, for assessing whether Sunrise Improvement Project will potentially trigger a Federal Major Modification or a SB288 major modification. The evaluation concluded that the project would not require application as Federal Major Modification or an SB288 major modification. Sunrise transmitted the data and NSR evaluation to SJVAPCD on March 5, 2021. The response is presented in Appendix C.

The SJVAPCD issued a letter deeming the permit application data adequate on March 31, 2021. A copy of the letter is included in Appendix D.

2.4 PROPOSED CHANGES TO THE CONDITIONS OF CERTIFICATION

This Petition proposes the following changes to the COCs included in the Commission Order Approving Project Modifications, issued November 19, 2001 (added text is underlined and deleted text is shown as strikethrough). Refinements to these Air Quality conditions may be necessary based on completion of the NSR evaluation.

- Update the equipment description to match the SJVAPCD air permit for the proposed project.

  Equipment Description:

  SJVUAPCD PERMIT NO. S-3746-1: ~~GENERAL ELECTRIC FRAME 7, MODEL PG724FA, NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRIC GENERATOR WITH DRY LOW NOX COMBUSTORS, SELECTIVE CATALYTIC REDUCTION, OXIDATION CATALYST, AND STEAM TURBINE LISTED WITH S-3746-2 (585 MW TOTAL PLANT NOMINAL RATING).~~ 190 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF GENERAL ELECTRIC FRAME 7FA, NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW-NOX COMBUSTORS, HEAT RECOVERY STEAM GENERATOR WITH DUCT FIRING, SCR, AND OXIDATION CATALYSTS (635 MW TOTAL PLANT NOMINAL RATING)

  SJVUAPCD PERMIT NO. S-3746-2: ~~GENERAL ELECTRIC FRAME 7, MODEL PG724FA, NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRIC GENERATOR WITH DRY LOW NOX COMBUSTORS, SELECTIVE CATALYTIC REDUCTION, OXIDATION CATALYST, AND STEAM TURBINE LISTED WITH S-3746-2 (585 MW TOTAL PLANT NOMINAL RATING).~~ 190 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF GENERAL ELECTRIC FRAME 7FA, NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW-NOX COMBUSTORS, HEAT RECOVERY STEAM GENERATOR WITH DUCT FIRING, SCR, AND OXIDATION CATALYSTS (635 MW TOTAL PLANT NOMINAL RATING)

- **AQ-9** – Update to match the SJVAPCD air permit for the proposed project: CTG shall be fired exclusively on natural gas, consisting primarily of methane and ethane, with a sulfur content no greater than ~~0.75~~ 0.25 grains of sulfur compounds (as S) per 100 dry standard cubic feet of natural gas. [~~District Rule 2201~~ 40 CFR 60.4330(a)(2), District NSR Rule, PSD SJ 01-01] Federally Enforceable Through Title V Permit

- **AQ-15** – Update to match the SJVAPCD air permit for the proposed project: Emission rates from each CTG, except during startup and shutdown events, shall not exceed any of the following:

  - PM10: 17.8 lbs/hr
  - SOx (as SO2): ~~1.55~~ 1.58 lbs/hr
  - NOx (as NO2): ~~15.96~~ 16.74 lbs/hr and 2.0 ppmvd @ 15% O2
  - VOC: ~~5.51~~ 5.84 lbs/hr and 2.0 ppmvd @ 15% O2
  - CO: ~~19.22~~ 20.38 lbs/hr and 4.0 ppmvd @ 15% O2
  - Ammonia: 10 ppmvd @ 15% O2

NOx (as NO2) emission concentration limit is a one-hour rolling average. Ammonia emission concentration limit is a 24-hour rolling average. All other emission concentration limits are three-hour rolling averages. [District Rules 2201, 4001, and 4703]

Protocol: Each one-hour period in a one-hour rolling average will commence on the hour. Each one-hour period in a 3-hour rolling average will commence on the hour. The 3-hour average will be compiled from the three most recent 1-hour periods. 24-hour average emissions will be compiled for a 24-hour period starting and ending at twelve-midnight. [District Rule 2201]

Verification: The Project owner shall provide records of the emissions as part of the quarterly reports of Condition AQ-31.

- **AQ-16** - Update to match the SJVAPCD air permit for the proposed project: Emission rates from each CTG shall not exceed the following:
  - PM10: 461.2 lbs/day
  - SOx (as SO2): ~~37.2~~ 38.1 lbs/day
  - NOx (as NO2): 1,170.9 lbs/day
  - VOC: 220.6 lbs/day
  - CO: 2,443.4 lbs/day

  [District Rule 2201]

  Verification: The Project owner shall provide records of the emissions as part of the quarterly reports of Condition AQ-31.

- **AQ-18** - Remove condition on emission offsets because the proposed project does not require emission offsets. AQ-18 was applicable to the previous project to convert the simple-cycle power plant to combined-cycle operations (CEC Commission Order Approving Project Modifications – November 19, 2001): ~~Prior to or upon startup of either S-3476-1 or '2, emission offsets shall be surrendered for all calendar quarters in the following amounts, at the offset ratio specified in Rule 2201 (6/15/95 version) in the following table at least 30 days prior to the commencement of construction.~~

	~~Quarter 1~~	~~Quarter 2~~	~~Quarter 3~~	~~Quarter 4~~
~~PM10~~	~~3,964~~	~~7,584~~	~~18,780~~	~~3,964~~
~~NOx (as NO2)~~	~~21,036~~	~~41,894~~	~~111,094~~	~~21,036~~

~~[District Rule 2201]~~

~~Prior to or upon startup of either S-3746-1 or '2, the following emission offsets shall be provided to the District to provide additional environmental benefits during the initial phase of this Project and shall be used towards the offset requirements, if needed, when the next phase of this Project is implemented:~~

	~~Quarter 1~~	~~Quarter 2~~	~~Quarter 3~~	~~Quarter 4~~
~~PM10~~	~~67,364~~	~~64,647~~	~~51,763~~	~~69,001~~
~~SOx (as SO2)~~	~~14,075~~	~~14,231~~	~~14,387~~	~~14,387~~
~~NOx (as NO2)~~	~~67,207~~	~~0~~	~~18,105~~	~~26,538~~

~~VOC~~	~~13,949~~	~~14,104~~	~~14,259~~	~~14,259~~

~~Prior to or upon startup of either S-3746-1, ‘2 and ‘3, the following emissions offsets shall be provided to the District to provide additional environmental benefits during the initial phase of phase II of the Sunrise Project and shall be used towards the offset requirements:~~

	~~Quarter 1~~	~~Quarter 2~~	~~Quarter 3~~	~~Quarter 4~~
~~PM10~~	~~10,541~~	~~8,266~~	~~20,637~~	~~16,404~~
~~NOx (as NO2)~~	~~9,157~~	~~4,195~~	~~0~~	~~6,571~~
~~VOC~~	~~4,983~~	~~3,111~~	~~5,791~~	~~6,648~~

~~Verification: The Project owner shall provide copies of all the necessary ERC certificates to the CPM no later than 30 days prior to the commencement of construction.~~

- **AQ-19** – Remove AQ-19 because the proposed project does not require emission offsets: ~~At least 30 days prior to commencement of construction, the Project owner shall provide the District with written documentation that all necessary offsets have been acquired or that binding contracts to secure such offsets have been entered into.~~

- **AQ-20** – Update to match the SJVAPCD air permit for the proposed project: ~~Source testing to demonstrate compliance with the NOx, CO, and VOC short-term emission limits (lbs/hr and ppmv @ 15% O2) shall be conducted within 60 days of initial operation of CTG and annually thereafter by District witnessed sampling of exhaust gas by qualified independent source testers. [District Rule 1081]~~

  Short term emission limits (lb/hr and ppmvd @ 15% O2) shall be measured annually by District witnessed in-situ sampling of exhaust gases by a qualified independent source test firm at full load conditions as follows - NOx: ppmvd @ 15% O2 and lb/hr, CO: ppmvd @ 15% O2 and lb/hr, VOC: ppmvd @ 15% O2 and lb/hr, PM10: lb/hr, and ammonia: ppmvd @ 15% O2. Sample collection to demonstrate compliance with ammonia emission limit shall be based on three consecutive test runs of thirty minutes each. [District Rules 1081 and 4703, and PSD SJ 01-01] Federally Enforceable Through Title V Permit

- **AQ-22** – Replace with updated AQ-20 to match the SJVAPCD air permit for the proposed project: ~~Source testing to demonstrate compliance with PM10 short-term emission limit (lbs/hr) shall be conducted within 60 days of initial operation, again within 9 months of initial operation during the winter (December, January, or February), and annually thereafter by District witnessed sampling of exhaust gas by qualified independent source testers. [District Rule 1081]~~

- **AQ-23** – Update to match the SJVAPCD air permit for the proposed project: ~~Source testing of startup NOx, CO, VOC, and PM10 mass emission rates shall be conducted for one of the gas turbine engines (S-3492-1-0 or ‘-2-0) upon initial operation and at least once every seven years thereafter by District witnessed in-situ sampling of exhaust gases by a qualified independent source test firm. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]~~

  Startup NOx, CO, and VOC mass emission limits shall be measured for one of the CTGs (S-3746-1, or -2) at least every seven years by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. [District Rule 1081] Federally Enforceable Through Title V Permit

- **AQ-26** – Update to match the SJVAPCD air permit for the proposed project: ~~(Deleted as of 4/11/2012 pursuant to Order No. 12-0411-4) The source test plans for the initial and seven-year source test shall include a method for measuring the CO/VOC surrogate relationship that will be used to demonstrate compliance with VOC lbs/hr, lbs/day, and lbs/twelve month rolling average emission limits upon combined cycle operation. [District Rule 2201]~~

  Startup NOx, CO, and VOC mass emission limits shall be measured for one of the CTGs (S-3746-1, or -2) at least every seven years by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. [District Rule 1081] Federally Enforceable Through Title V Permit

- **AQ-27** – Update to match the SJVAPCD air permit for the proposed project: The following test methods shall be used:

  PM10: EPA method 5 (front half and back half),

  NOx: EPA method 7E or 20

  CO: EPA method 10 or 10B

  O2: EPA method 3, 3A, or 20

  VOC: EPA method 18 or 25

  Ammonia: BAAQMD ST-18

  Fuel gas sulfur content: ASTM D3246 or ASTM 06228.

  EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [40 CFR 60.4400, District Rules 1081, 4001~~, and~~ 4703, and PSD SJ 01-01] Federally Enforceable Through Title V Permit

- **AQ-29** – Update to match the SJVAPCD air permit for the proposed project: ~~The project owner shall maintain hourly records of NOx, CO, and ammonia emission concentrations (ppmv @ 15% O2), and hourly, daily, and annual records of NOx and CO emissions. Compliance with the hourly, daily, and annual VOC emission limits shall be demonstrated by the CO CEM data and the CO/VOC relationship determined by annual CO and VOC source tests upon combined cycle operation. [District Rule 2201]~~

  The permittee shall maintain hourly records of NOx, CO, and ammonia emission concentrations (ppmvd @ 15% O2), and hourly, daily, and twelve month rolling average records of NOx and CO emissions. [District NSR Rule] Federally Enforceable Through Title V Permit

- **AQ-30** – Update to match the SJVAPCD air permit for the proposed project: The ~~project owner~~ permittee shall maintain records of SOx lbs/hr, lbs/day, and lbs/twelve month rolling average emissions. SOx emissions shall be based on fuel use records, natural gas sulfur content, and mass balance calculations. [District ~~Rule 2201~~ NSR Rule] Federally Enforceable Through Title V Permit

- **AQ-31** – Update to match the SJVAPCD air permit for the proposed project: ~~The project owner shall maintain the following records for each CTG: occurrence, duration, and type of any startup, shutdown, or malfunction; emission measurements; total daily and annual hours of operation; and hourly quantity of fuel used. [District Rules 2201 and 4703]~~

  The owner or operator shall maintain records that contain the following: the occurrence and duration of any start-up, shutdown or malfunction, performance testing, evaluations, calibrations, checks, adjustments, any periods during which a continuous monitoring system or monitoring device is inoperative, maintenance of any CEM system that has been installed pursuant to District Rule 1080 (as amended 12/17/92), and emission measurements. [40 CFR 60.7(b), 40 CFR 60.8(d), District Rules 1080 and 2201, 40 CFR 64 and PSD SJ 01-01] Federally Enforceable Through Title V Permit

- **AQ-32** – Replace with updated AQ-31 to match the SJVAPCD air permit for the proposed project: ~~The project owner shall maintain the following records for the continuous emissions monitoring system (CEMS): performance testing, evaluations, calibrations, checks, maintenance, adjustments, and any period of non-operation of any continuous emissions monitor. [District Rules 2201 and 4703]~~
- **AQ**-39 – New Source Performance Standards. The owner or operator shall comply with the provisions of 40 CFR Part 60, Subpart KKKK dated July 6, 2006. The NOx emissions except during start-up and shut down shall not exceed 25 ppmvd @ 15% O2. The SOx emissions shall not exceed 0.060 lb SO2 per MMBtu. Compliance with the NOx limit shall be achieve through the use of selective catalytic reduction. The owner or operator shall maintain a continuous emission monitoring system to demonstrate compliance. The use of pipeline quality natural gas satisfies the SO2 limit. No other SO2 monitoring requirements apply. Other conditions apply limits to NOx and SO2 and compliance with those conditions guarantees compliance with 40 CFR Part 60, Subpart KKKK. The project owner shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]
- **AQ-40** – Update to match the SJVAPCD air permit for the proposed project: ~~The project owners shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions; nature and cause of excess (averaging period used for data reporting shall correspond to the averaging period for each respective emission standard); corrective actions taken and preventive measures adopted; applicable time and date of each period during a CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]~~

  Operators of CEM systems installed at the direction of the APCO shall submit a written report for each calendar quarter to the APCO and EPA (Attn: AIR-5). The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess emissions, nature and cause of excess (if known}, corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred; And reports on opacity monitors giving the number of three minute periods during which the average opacity exceeded the standard for each hour of operation. The averaged may be obtained by integration over the averaging period or by arithmetically averaging a minimum of four equally spaced instantaneous opacity measurements per minute. Any time exempted shall be considered before determining the excess averages of opacity. [40 CFR 64, District Rule 1080 and PSD SJ 01-01] Federally Enforceable Through Title V Permit
- **AQ-41** – Remove AQ-41 as this is already completed: ~~The project owner will cease the simple cycle operation of the Sunrise Power Project and convert it to combined cycle operation prior to January 1, 2004.~~
- **AQ-49** - Remove AQ-49 to match the SJVAPCD air permit for the proposed project. The SJVAPCD air permit already has Condition 36 (AQ-14 in CEC Conditions of Certification) that specifies the combined startup emissions from both gas turbine engines and heat recovery steam generator

exhausts: NOx – 700 lb and CO – 1,580 lb in any one hour: ~~(Deleted 4/11/12 pursuant to Order No. 12-0411-4) By two hours after turbine initial firing, CTG exhaust emissions shall not exceed any of the following:~~

~~NOx (as NO2): 10.3 ppmv @ 15% O2~~

~~CO: 25 ppmv @ 15% O2~~

~~[District Rule 4703]~~

~~Compliance with the aforementioned limits will commence on the clock hour following the 120th minute after initial firing. These emission limits are three hour rolling averages.~~

- **AQ-50** – Update to match the SJVAPCD air permit for the proposed project: Emission rates from BOTH CTGs (S-3746-1 and '2), on days when a startup or shutdown occurs for either or both turbines, shall not exceed any of the following:

  - PM10: 922.3 lbs/day
  - SOx (as SO2): ~~74.4~~ <u>76.3</u> lbs/day
  - NOx (as NO2): 2,341.8 lbs/day
  - VOC: 441.2 lbs/day
  - CO: 4,886.8 lbs/day

  [District Rule 2201]

  Verification: The Project owner shall provide records of the emissions as part of the quarterly reports of Condition AQ-31.

- **AQ-61** – Remove AQ-61 because this condition defines commissioning activities that already occurred between March 1, 2003 and December 31, 2003: ~~Relief shall be granted from Conditions of Certification AQ-7, AQ-10, AQ-14, AQ-15, AQ-16, AQ-20, AQ-22, AQ-49 and AQ-50 for the duration of the Commissioning period of the Sunrise Phase II combined cycle power project.~~

  ~~During Commissioning, NOx emissions shall not exceed 17,770 lbs/day.~~

  ~~During Commissioning but prior to the oxidation catalyst being installed, CO emissions shall not exceed 27,513 lbs/day.~~

  ~~During Commissioning and following the installation of the oxidation catalyst, CO emissions shall not exceed 5,703 lbs/day.~~

  ~~Commissioning activities shall not exceed 120 days cumulatively of operation. Commissioning activities shall occur between March 1, 2003, and December 31, 2003.~~

  ~~The owner/operator shall record and quantify, via CEMS or District approved source testing, the actual NOx and CO emissions associated with the Commissioning period, except for the first 24-hours after the first initial firing.~~

- **AQ-62** – Remove AQ-62 as this condition was applicable to simple cycle operation only: ~~Reduced load period is defined as the time during which a gas turbine is operated at less than rated capacity in order to change the position of the exhaust gas diverter gate. Each reduced load shall not exceed one hour. [District Rule 4703, 3.23] Federally Enforceable through Title V Permit~~

- **AQ-xx** - Add a new AQ to match the SJVAPCD air permit conditions for compliant dormant emissions units: <u>While dormant, the fuel line shall be physically disconnected from the unit. The</u>

<u>Permittee shall submit written notification to the District upon designating the unit as dormant or active. While dormant, normal source testing shall not be required. [District Rule 2080]</u>

2.5 NECESSITY OF PROPOSED MODIFICATIONS

The proposed modifications are necessary to enable the Petitioner to increase maximum net output at the interconnection point from approximately 585 MW to 635 MW nominal at an ambient temperature of 30 ºF with a corresponding 3 to 4% improvement in efficiency (i.e., generation output per unit of fuel input).

2.6 PROPOSED MODIFICATIONS ARE BASED UPON INFORMATION PREVIOUSLY UNKNOWN TO PETITIONER

The Petitioner was not aware that modifications could be made to optimize the turbine output and efficiency at the time of the previous Petition application.

2.7 PROPOSED MODIFICATIONS ARE BASED ON NEW INFORMATION THAT CHANGE OR UNDERMINE THE ASSUMPTIONS, RATIONALE, FINDINGS, OR OTHER BASES OF THE FINAL DECISION

The Project will increase the fuel input as part of the efficiency improvement and this will result in a small increase in hourly emissions of SOx, NOx, VOC and CO. In addition, the Project will result in a minor daily increase in emissions of SOx due to the increased fuel consumption of the gas turbines. However, the Project will not result in an increase in annual emissions. As described in Sections 2.1 and 2.3, this Petition proposes changes to the COCs on the hourly and daily emission limits. Appendix A contains the authority to construct application prepared on behalf of the Petitioner by its consultant ERM-West, Inc. (ERM). Included in the SJVAPCD permit application is a regulatory analysis for the applicable District and federal air requirements for the Project. Compliance with applicable District and federal rules are expected and the proposed modifications should be permitted. Appendix B contains the response to the SJVAPCD Notice of Incomplete Application letter.

2.8 ANALYSIS OF THE ENVIRONMENTAL IMPACTS FROM THE PROPOSED MODIFICATIONS

The proposed modifications will not have significant adverse impacts on the environment; as such, there is no need to discuss further any mitigation measures necessary to offset significant impacts to the environment as a result of the Project. A summary of the environmental resource areas as well as the associated analysis is provided in Table 2 below.

Table 2: Environmental Analysis Summary

Resource Area	Analysis
Air Quality	There will be no additional emission units added to the facility. The Project will increase the fuel input as part of the output and efficiency improvement and this will result in a small increase in hourly emissions of SOx, NOx, VOC and CO. In addition, the Project will result in a minor daily increase in emissions of SOx due to the increased fuel consumption of the gas turbines. However, the Project will not result in an increase in annual emissions. The SJVAPCD air quality thresholds

Resource Area	Analysis
	of significance for criteria pollutants are based on annual emissions.[1] Since the Project will not result in an increase in annual emissions, air quality impacts will not be significant. Included in the SJVAPCD permit application is a regulatory analysis for the applicable District and federal air requirements for the Project. Compliance with applicable District and federal rules are expected. Installation of the equipment will take no longer than a maintenance outage and will require minimal construction equipment for assembly. No significant adverse impacts.
Biological Resources	The proposed modifications will not require any change to biological resources. No impact.
Cultural Resources	The proposed modifications will not require ground disturbance activities. No impact.
Geology and Paleontology	The proposed modifications will not require ground disturbance activities. No impact.
Hazardous Materials	The proposed modifications will not involve new hazardous materials or storage. No impact.
Land Use	The proposed modifications will not require any change to land use. No impact.
Noise and Vibration	The proposed modifications will not require any new noisy or heavy equipment. No impact.

[1] SJVAPCD Air Quality Thresholds of Significance (March 19, 2015): http://www.valleyair.org/transportation/0714-GAMAQI-Criteria-Pollutant-Thresholds-of-Significance.pdf.

Resource Area	Analysis
Public Health	The proposed Project will not result in an increase of potentially hazardous air pollutants; therefore, an evaluation of the associated health risk is not required. Included in the SJVAPCD permit application is a regulatory analysis for the applicable District and federal air requirements for the Project. Compliance with applicable District and federal rules are expected. No significant adverse impacts.
Socioeconomic Resources	The proposed modifications will not require extensive labor for installation or operation. No impact.
Soil and Water Resources	The proposed modifications will not cause ground disturbances and will not require additional water resources. No impact.
Traffic and Transportation	The proposed modifications will not require offsite staging or laydown and heavy haul deliveries. The project-related traffic and transportation and associated onsite personnel for this modification will be akin to normal maintenance activities. No impact.
Visual Resources	The proposed modifications will not change the physical appearance of the facility. No impact.
Waste Management	The proposed modifications will not change the waste production level at the facility. No impact.
Worker Safety and Fire Projection	Activities to be performed on the turbines for the proposed modifications will comply with existing worker safety and fire protection requirements. No impact.

2.9 IMPACTS OF THE MODIFICATIONS ON THE FACILITY'S ABILITY TO COMPLY WITH APPLICABLE LORS

As described in Section 2.6, Appendix A contains the air permit application prepared on behalf of the Petitioner by its consultant ERM that was submitted to the SJVAPCD for the Project. Included in the SJVAPCD permit application is a regulatory analysis for the applicable District and federal air requirements for the Project. The proposed modifications will not impact Sunrise's ability to comply with all applicable LORS.

2.10 IMPACTS OF THE MODIFICATIONS TO THE PUBLIC

The proposed modifications will not require any new noisy or heavy equipment. The proposed modifications will not alter the physical appearance of the facility. The proposed modifications will not require offsite staging or laydown and heavy haul deliveries. The project-related traffic and transportation and associated onsite personnel for this modification will be akin to normal maintenance activities.

As described in Section 2.6, the Project will increase the fuel input as part of the output and efficiency improvement and this will result in a small increase in hourly emissions of SOx, NOx, VOC and CO. The Project will result in a minor daily increase in emissions of SOx (less than 2.0 lb) due to the increased fuel consumption of the gas turbines. However, the Project will not result in an increase in annual emissions. Since the Project will not result in an increase in annual emissions, air quality impacts will not be significant. In addition, the Project will not result in an increase of potentially hazardous air pollutants; therefore, an evaluation of the associated health risk is not required.

Included in the SJVAPCD permit application is a regulatory analysis for the applicable District and federal air requirements for the Project. Compliance with applicable District and federal rules is expected. No significant adverse impacts are expected.

2.11 POTENTIAL EFFECT ON NEARBY PROPERTY OWNERS, THE PUBLIC, AND THE PARTIES IN THE APPLICATION PROCEEDING

Nearby property owners, the Public, and Parties in the Application Proceeding will not be affected by the proposed modification since the proposed modification will have no significant environmental effects and will be in compliance with applicable LORS. Because there are no potentially affected property owners, a list of property owners is not included in this Petition.

APPENDIX A SJVAPCD PERMIT APPLICATION FOR MODIFICATION OF GAS TURBINE #1 AND GAS TURBINE #2

San Joaquin Valley Air Pollution Control District
Authority to Construct

Modification of Gas Turbines

Facility Name:	Sunrise Power Company	Date:	October 2020
Mailing Address:	12857 Sunrise Power Road Fellows, CA 93224	Engineer:	
		Lead Engineer:	Leonard Scandura
Contact Person:	George Piantka		
Telephone:	760-930-1505		
Fax:			
E-mail:	George.Piantka@nrg.com		
Application #(s):	S-3746-1-13 and S-3746-2-13		
Projects #:			
Deemed Complete:			

I. PROPOSAL

The Sunrise Power Company, LLC (Sunrise) facility is a 585-megawatt (MW) nominally rated 2x1 combined cycle power facility consisting of the following major components:

- Two 160 MW (Nominal) General Electric Frame 7FA, Natural Gas Fired Combustion Turbine Generators (CTG1 and CTG2) Equipped with Dry Low NOx (DLN) Combustors
- Two Heat Recovery Steam Generators (HRSG) with Duct Firing
- One Steam Turbine Generator (STG)
- Selective Catalytic Reduction (SCR) and Oxidation Catalyst for CTG1 and CTG2

The facility is located within the jurisdiction of the San Joaquin Valley Air Pollution Control District (SJVAPCD) and has a Title V Operating Permit. The SJVAPCD Identification Number is S-3746. The permit consists of four permitted units at the site, including the two combined-cycle power generating units, a 137,000 gallon per minute cooling tower, and a portable diesel fuel-fired engine driving an electrical generator. The portable diesel fuel-fired engine electrical generator intended for maintaining and preserving critical equipment during loss of grid power has not been utilized to date. This equipment is maintained in the permit for contingency. The SJVAPCD Title V permit has conditions limiting the mass emissions of volatile organic compounds (VOC), oxides of nitrogen (NOx), carbon monoxide (CO), sulfur oxides (SOx), particulate matter 10 micrometers in diameter and smaller (PM_{10}/$PM_{2.5}$) and ammonia (NH_3) on an hourly, daily, and annual basis. Separate provisions apply to startup and shutdowns. The permits also have conditions limiting the concentration of NOx, VOC, CO and NH_3 to 2.0 parts per million by volume on a dry basis of 15 percent oxygen (ppmvd @ 15% O_2), 2.0 ppmvd @ 15% O_2, 4 ppmvd @ 15% O_2 and 10 ppmvd @ 15% O_2 respectively. The NOx ppmvd and lb/hr limits are averaged over a one-hour rolling average excluding startup and shutdown. The CO, PM, SOx, VOC ppmvd and lb/hr limits are based on a three-hour rolling average. The ammonia slip limit is based on a twenty-four hour average. The concentration limits do not apply during startup or shutdown.

Sunrise plans to upgrade this facility by making improvements that include the installation of a new gas turbine section, combustion system and control system to the CTGs. These improvements will increase the power output and improve efficiency. Although the proposed project will increase output, increase some hourly and daily pollutant masses and increase the maximum hourly fuel consumption, this project will not result in an increase in annual emissions above existing permitted limits. In addition, Sunrise will maintain pollutant concentration limits in the existing permits (Permit # S-3746-1-12 and S-3746-2-12). Sunrise proposes revisions to Conditions 20, 30, 37, 38, and 39. Condition 20 revision is to clarify that CTGs will be subject to 40 CFR Part 60, Subpart KKKK (i.e., 40 CFR 60.4380 (b)(1)) after the upgrades. Consequently, the regulatory citation 40 CFR 60.4380 (b)(1) was updated in several permit conditions to reflect the corresponding change to Condition 20. Sunrise also proposes to remove Condition 30 as this condition was applicable to simple cycle operation only. Finally, Sunrise proposes to modify Conditions 37, 38 and 39 to reflect changes to the SOx, NOx, VOC and CO hourly mass emission rates and SOx daily mass emission rate per turbine and combined for both turbines in Permit #'s S-3746-1-12 and S-3746-2-12. Complete proposed permit conditions are presented in Appendix A with changes depicted in strikeout underscore.

II. APPLICABLE RULES

District Rule 1070	Inspections (12/17/92)
District Rule 1080	Stack Monitoring (12/17/92)
District Rule 1081	Source Sampling (12/16/93)
District Rule 1100	Equipment Breakdown (12/17/92)
District Rule 2010	Permits Required (12/17/92)
District Rule 2201	New and Modified Stationary Source Review Rule (8/15/19)
District Rule 2410	Prevention of Significant Deterioration (6/16/2011)
District Rule 2520	Federally Mandated Operating Permits (8/15/19)
District Rule 4001	New Source Performance Standards (4/14/99)
District Rule 4101	Visible Emissions (2/17/05)
District Rule 4102	Nuisance (12/17/92)
District Rule 4201	Particulate Matter Concentration (12/17/92)
District Rule 4202	Particulate Matter Emission Rate (12/17/92)
District Rule 4301	Fuel Burning Equipment (12/17/92)
District Rule 4703	Stationary Gas Turbines (9/20/07)
District Rule 4801	Sulfur Compounds (12/17/92)
CH&SC 44300	Air Toxics "Hot Spots"

III. PROJECT LOCATION

Sunrise Power Company is located at 12857 Sunrise Power Road in Fellows, CA.

SW 1/4 Sec 23, T31S, R22E — Mt. Diablo Base and Meridian (MDB&M)

The facility is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project. A map of the project location is included in Appendix B.

IV. PROCESS DESCRIPTION

The Sunrise facility is a 585 MW combined cycle power system that includes the following major components:

- Two 160 MW (Nominal) General Electric Frame 7FA, Natural Gas Fired Combustion Turbine Generators, CTG1 and CTG2
- Two Heat Recovery Steam Generators with Duct Firing
- One Steam Turbine Generator
- Selective Catalytic Reduction and Oxidation Catalyst

This combined cycle power system produces electricity from the two CTGs and the STG. Fuel for the CTGs and duct burners is pipeline natural gas. Heat from the CTG exhaust gases is recovered in HRSGs to generate steam and to reheat steam. Steam exiting the HRSGs is directed to a single STG, which generates approximately 173 MW with the duct burners offline and approximately 240 MW with the duct burners operating at maximum fired duty. With the duct burners offline, the current overall gross output of the power plant is approximately 520 MW at design ambient conditions, while approximately 585 MW is produced with the duct burners in-service. The total maximum duct burner heat input is about 820 MMBtu/hr (410 MMBtu/hr per unit) at higher heating value.

The SCR emission control system is used to reduce NOx emissions from the natural gas fired combustion turbine. The SCR system consists of an anhydrous ammonia (NH_3) storage, injection system, catalyst and catalyst housing. The SCR system selectively reduces NOx emissions by injecting anhydrous NH_3 into the exhaust gas stream. Nitrogen oxides, ammonia and oxygen react on the surface of the catalyst to form N_2 and water. Oxidation catalyst (EmeraChem) is used to reduce emissions of CO and VOC.

Sunrise is connected to the California Power Grid through the Buttonwillow Substation.

Sunrise plans to make improvements to the existing system. Sunrise is proposing to install enhanced hardware to the combustor and turbine sections of CTG1 and CTG2, and optimize the control logic of the gas turbines. This project is referred to as Sunrise Power Improvement (the Project). The proposed performance upgrades include a new combustion system with higher gas turbine firing temperatures and a new turbine section, resulting in increased MW output and improved efficiency made possible by improved cooling, sealing enhancements and advanced materials. The new DLN combustion system will achieve a

NOx concentration of 9.0 ppmvd @ 15% O_2 compared to the current OEM guarantee of 15 ppmvd @ 15% O_2. These emission concentrations are prior to the SCR.

The performance upgrades are augmented by the addition of an upgraded Mark VIe turbine control system incorporating advanced combustion optimization capabilities, which also provides enhanced operational flexibility. The overall goal of the Project is to increase the output and efficiency of each turbine so as to improve the overall performance of the Sunrise combined cycle facility without a change in permitted emissions. The proposed modifications will increase maximum net output at the interconnection point from approximately 585 MW to 635 MW nominal at an ambient temperature of 30 degrees Fahrenheit (ºF) with a corresponding 3 to 4% improvement in efficiency (i.e., generation output per unit of fuel input). The output increase is provided as an estimate from model projections. The actual change will depend on ambient conditions. The Sunrise facility will continue to comply with the annual emission limits in the San Joaquin Valley Air Pollution Control District (District) Permits to Operate. There are calculated increases in the maximum hourly emissions because of increased fuel consumption combined with default emission factors and permit concentration limits.

The upgraded CTGs will require a period of commissioning. The commissioning period is expected to be about 80 hours for each CTG. In addition there may be 6 months between commissioning of the two CTGs. The commissioning is expected to occur in three phases. The first phase will be “break-in” and should take about 24 hours. The next phase is tuning and is expected to require another 24 hours. The remainder of the commissioning time will be for testing. Sunrise expects testing will be at normal operation but may include a number of stops and starts.

V. EQUIPMENT LISTING

Equipment Description:

Permit Unit S-3746-1-13:

190 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF GENERAL ELECTRIC FRAME 7FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW-NOX COMBUSTORS, HEAT RECOVERY STEAM GENERATOR WITH DUCT FIRING, SCR, AND OXIDATION CATALYSTS (635 MW TOTAL PLANT NOMINAL RATING)

Permit Unit S-3746-2-13:

190 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF GENERAL ELECTRIC FRAME 7FA, NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW-NOX COMBUSTORS, HEAT RECOVERY STEAM GENERATOR WITH DUCT FIRING, SCR, AND OXIDATION CATALYSTS (635 MW TOTAL PLANT NOMINAL RATING)

VI. EMISSION CONTROL TECHNOLOGY EVALUATION

The existing CTGs will be retrofit with improved DLN combustors. The replacement DLN combustors will achieve a NOx concentration of 9 ppmvd @ 15% O_2. DLN burner technology uses a two-stage combustor that premixes a portion of the air and fuel in the first stage and the remaining air and fuel are injected into the second stage. This two-stage process optimizes the mixing of combustion air and fuel, thereby minimizes the amount of air required and controlling peak flame temperatures, which results in low NOx emissions.

Each of the HRSGs on the CTGs' exhaust is currently fitted with SCR and an oxidation catalyst system. The oxidation catalyst on each unit will achieve VOC and CO Best Available Control Technology (BACT) performance levels. The "Technologically Feasible" BACT is 4.0 ppmvd @ 15% O_2 for CO and 1.5 ppmvd @ 15% O_2 for VOC. The "Achieved in Practice" BACT for CO and VOC are 6.0 ppmvd @ 15% O_2 and 2.0 ppmvd @ 15% O_2, respectively. The existing permit limit for CO is 4 ppmvd @ 15% O_2 and for VOC the limit is 2.0 ppmvd @ 15% O_2. No changes in the current permit concentration permit limits are proposed as the facility meets BACT and will continue to meet BACT with the implementation of the proposed changes.

The SCR uses an ammonia injection grid in the HRSG duct upstream of the catalyst bed. The catalyst bed is integrated into the HRSG because it must be located at a point in the exhaust stream where the gas temperature is between 600 and 800°F. The ammonia reduces NOx to N_2 and water in the presence of the catalyst. The system NOx emissions after control will be no more than 2.0 ppmvd @ 15% O_2 at all normal operating loads but excludes startup and shutdown periods. Since unreacted ammonia (ammonia slip) is present in the exhaust gas downstream of the SCR, ammonia slip is limited to 10 ppmvd @ 15% O_2.

Continuous emissions monitoring systems (CEMs) are in place to sample, analyze, and record NOx, CO, and O_2 concentrations in the stack gas. There is one CEM for each unit. NOx concentrations are measured before and after the SCR unit. The NH_3 slip is determined using NOx reduction measurements and NH_3 consumption.

VII. GENERAL CALCULATIONS

The current permit does not limit Sunrise to any specific number of hours of operation. Actual emissions vary depending on ambient temperature, load and numbers of starts. In the permit application filed in 2001 for the combined cycle unit, Sunrise identified two operating scenarios that would result in worst case annual emissions. The scenarios were then used to arrive at annual emission limits as well as quarterly values for offsets evaluation. As indicated, Sunrise proposes the current annual emission limits remain in the ATCs and permits to operate. The maximum hourly fuel consumption will increase, which will increase the maximum hourly emission rates for SOx, NOx, VOC and CO. The increases are 0.03 lb/hr for SOx, 0.78 lb/hr for NOx, 0.33 lb/hr for VOC, and 1.16 lb/hr for CO.

There are many possible operating scenarios. Sunrise has developed an operational scenario which is most representative of annual operations for emissions evaluation. The following presents the assumptions for the emissions calculations contained herein.

A. Assumptions

- BACT emission concentration limits of 2.0 ppmvd @ 15% O_2, 4 ppmvd @ 15% O_2, and 2.0 ppmvd @ 15% O_2 remain the same as the current permit emission concentration limits for NOx, CO, and VOC, respectively, at all operating loads (except during startups and shutdowns).

- SOx emissions are based on 1,041 Btu/scf (HHV) for natural gas and a natural gas sulfur content of 0.25 gr. S/100 scf.

- The maximum total (combined for both CTGs) hourly NOx and CO emissions are based on each CTG experiencing one startup with the highest hourly NOx and CO emission rate predicted for a cold startup

- Maximum daily $PM_{10}/PM_{2.5}$, SOx, NOx, VOC, and CO emissions for each CTG (@ BACT ppmvd limits) were estimated assuming 100% capacity, with 100% duct burner firing, at an ambient temperature of 30°F, one startup, one shutdown and 19 hours and 10 minutes of baseload operation. This is the same as was used for the 2001 application except the baseload emission were based on 15°F. For the upgraded CTGs, there are other constraints that limit the facility operation at 15°F. Therefore, 30ºF was chosen and there remain some equipment limitations that restrict operation to less than the theoretical maximum.

- Maximum 1st and 4th quarter NOx, VOC, CO, $PM_{10}/PM_{2.5}$ and SOx emissions for each CTG (@ BACT ppmvd limits) were estimated assuming 100% capacity, at an average ambient temperature of 30°F, for the Proposed Operating Scenario below.

- Maximum 2nd quarter NOx, VOC, CO, $PM_{10}/PM_{2.5}$ and SOx emissions for each CTG (@ BACT ppmvd limits) were estimated assuming 100% capacity, at an average ambient temperature of 65°F, for the Proposed Operating Scenario below.

- Maximum 3rd quarter NOx, VOC, CO, PM_{10}/$PM_{2.5}$ and SOx emissions for each CTG (@ BACT ppmvd limits) were estimated assuming 100% capacity, at an average ambient temperature of 115°F, for the Proposed Operating Scenario below.

- Sunrise plans on 182 startups per year compared to the 100 that was presented in the 2001 permit application. A ratio of 1.82 (Proposed Starts/Current Starts = 182 starts/100 starts = 1.82) was applied to the 2001 permit information to determine the number and types of starts and startup and shutdown per quarter. Startup and shutdown hours per quarter are as follows: Quarter 1 = 180 hours; Quarter 2 = 171 hours; Quarter 3 = 39 hours; Quarter 4 = 180 hours.

- Startup emissions for VOC, NOx and CO in lb/event were calculated using the Sunrise startup emission data and minutes per event. The current startup times are the same as found in the 2001 permit application. Startup emissions for SOx and PM_{10}/$PM_{2.5}$ in lb/event were taken from the 2001 permit application. PM_{10}/$PM_{2.5}$ for hot start should be similar to normal operations. The cold start maximum lb/hr value was used for the hot start.

- Quarterly and annual emissions are based on the following proposed hypothetical operating schedule:

Table 1. Proposed Operating Scenario

		Quarter 1	**Quarter 2**	**Quarter 3**	**Quarter 4**	**Annual**
Number of Startup Events	Hot (60 min. each)	16	16	6	16	54
	Warm (128 min. each)	27	28	9	27	91
	Cold (230 min. each)	13	11	0	13	37
Number of Shutdown Events	60 minutes each	56	55	15	56	182
Hours of Operation	Duct Burners Off	554	568	193	276	1,591
	Duct Burners On	1,145	1,175	1,931	1,471	5,722
Downtime Hours		282	268	43	282	875
Maximum Hr/Qtr (includes startups & shutdowns)		2,160	2,184	2,208	2,208	8,760
Maximum Operating Hours		1,699	1,743	2,125	1,747	7,313

B. Emission Factors

Maximum Concentrations (BACT Performance Limits for NOx, CO and VOC)

The maximum air contaminant concentrations (ppmvd @ 15% O2) remain the same as the current permit emission concentration limits for NOx, CO, and VOC as they represent BACT and Sunrise is not proposing any limits on the types of operation. The pollutant concentration limits are summarized below:

Table 2. Pollutant Concentration Limits ppmvd @ 15% O2

PM10/PM2.5	SOx	NOx (1 hour average)	VOC (3 hr rolling average)	CO (3 hr rolling average)
N/A	0.14	2.0	2.0	4

Short-Term Mass Emission Rates during Baseload Operation

The proposed maximum criteria air contaminant mass emission rates occurring @ 100% load for the CTGs are provided in Table 3. These emission rates are used to establish the maximum hourly and daily emission limits for the CTGs.

Table 3. Maximum Hourly Emissions with Duct Burner Firing – Post Project

PM10/PM2.5	SOx	NOx (1 hour average)	VOC (3 hr rolling average)	CO (3 hr rolling average)
17.8	1.58	16.74	5.84	20.38

The proposed hourly emission rates used to calculate 1st and 4th quarter emissions are based on 100 percent load and 30°F, with and without duct burner firing. The 2nd quarter emissions are based on 100 percent load and 65°F, with and without duct burner firing. The 3rd quarter emissions are based on 100 percent load and 115°F, with and without duct burner firing. The proposed emission rates are based on emission rates from modeled performance data. These emission rates are used to establish quarterly and annual emissions limits for the CTGs.

The hourly emission rates listed in Condition 37 of permit S-3746-1-12 and S-3745-2-12 will need to be changed to those listed in Table 3 as follows:

- *Emission rates from each CTG, except during startup and/or shutdown, shall not exceed any of the following: PM_{10} - 17.8 lb/hr, SOx (as SO_2) - ~~1.55~~ 1.58 lb/hr, NOx (as NO_2) - ~~15.96~~ 16.74 lb/hr and 2.0 ppmvd@ 15% O_2, VOC - ~~5.51~~ 5.84 lb/hr and 2.0 ppmvd@ 15% O_2, CO - ~~19.22~~ 20.38 lb/hr and 4 ppmvd@ 15% O_2, ammonia - 10 ppmvd@ 15%O_2. NOx (as NO_2) ppmvd and lb/hr limits are a one-hour rolling average. Ammonia emission limit is a twenty-four hour rolling average. All other ppmvd and lb/hr limits are three-hour rolling averages. If a CTG* *is in either startup or shutdown mode during any portion of a clock hour, that unit will not be subject to the aforementioned limits during that clock hour. [40 CFR 60.332(a)(l), District Rules 2201, 4001, 4703, and PSD SJ 01 -01] Federally Enforceable Through Title V Permit.*

Table 4. Hourly Emissions (For 1st and 4th Quarter Emissions)

	$PM_{10}/PM_{2.5}$	SOx	NOx (1-hour average)	VOC (3-hr rolling average)	CO (3-hr rolling average)
Mass Emission Rates with Duct Burner Firing (per turbine, lb/hr)	17.8	1.58	16.74	5.84	20.38
Mass Emission Rates without Duct Burner Firing (per turbine, lb/hr)	13.4	1.36	14.36	2.85	17.49

Table 5. Hourly Emissions (For 2nd Quarter Emissions)

	$PM_{10}/PM_{2.5}$	SOx	NOx (1-hour average)	VOC (3-hr rolling average)	CO (3-hr rolling average)
Mass Emission Rates with Duct Burner Firing (per turbine, lb/hr)	17.5	1.52	16.15	5.63	19.66
Mass Emission Rates without Duct Burner Firing (per turbine, lb/hr)	12.2	1.27	13.41	2.71	16.33

Table 6. Hourly Emissions (For 3rd Quarter Emissions)

	$PM_{10}/PM_{2.5}$	SOx	NOx (1-hour average)	VOC (3-hr rolling average)	CO (3-hr rolling average)
Mass Emission Rates with Duct Burner Firing (per turbine, lb/hr)	17.0	1.45	15.44	5.38	18.80
Mass Emission Rates without Duct Burner Firing (per turbine, lb/hr)	11.7	1.18	12.52	2.56	15.24

Startup/Shutdown Emission Rates

Below is a summary of the proposed maximum expected emissions during cold, warm, and hot startup events and shutdown events. The emission rates for NOx and CO were taken from actual CEMs readings and the period with the highest emissions (30 minutes minimum) was selected and used to estimate the emissions per event. For VOC the highest normal operating concentration rate without duct firing was selected and used to calculate the emissions per event. $PM_{10}/PM_{2.5}$ emissions per startup event were taken from the 2001 permit application. Hot start $PM_{10}/PM_{2.5}$ emissions are expected to be similar to normal operations. Sunrise selected the cold start maximum hourly rate for conservatism.

For shut downs, Sunrise selected the worst case $PM_{10}/PM_{2.5}$ emission rate for CTG firing only and assumed that would apply during the entire shutdown period. SOx emissions were based on maximum fuel consumption and 0.25 grains of hydrogen sulfide per dry standard cubic feet of fuel. Shutdown emissions for NOx, CO and VOC were taken from the 2001 permit application. Actual emissions are typically lower.

Table 7. Startup & Shutdown Emissions (per Turbine)

	$PM_{10}/PM_{2.5}$ (lb/event)	SOx (lb/event)	NOx (lb/event)	VOC (lb/event)	CO (lb/event)
Cold Startup (230 minutes/event)					
Maximum lb/hr	22	1.67	82.0	4.26	329.0
Total lb/event	85	6.40	314.3	16.3	1,261
Warm Startup (128 minutes/event)					
Maximum lb/hr	40	1.67	36.1	4.26	16.30
Total lb/event	85	3.60	77.0	9.09	34.8
Hot Startup (60 minutes/event)					
Maximum lb/hr	22	1.67	28.0	4.26	36.0
Total lb/event	22	1.67	28.0	4.26	36.0
Shutdown (60 minutes)					
Maximum lb/hr	13.4	1.55	115.0	30.0	325.0
Total lb/event	13.4	1.55	115.0	30.0	325.0

C. Potential to Emit Prior to Modification (PEPM):

The PEPM is shown in the table below.

Table 8. Potential to Emit Prior to Modification

Permit Unit	$PM_{10}/PM_{2.5}$ (lb/day)	SOx (lb/day)	NOx (lb/day)	VOC (lb/day)	CO (lb/day)
S-3746-1-12	461.2	37.2	1,171	220.6	2,443
S-3746-2-12	461.2	37.2	1,171	220.6	2,443
S-3746-3-6	15.78[1]	0	0	0	0
S-3746-4-5	4.2	0.1	78.3	5.6	73.5
Total Daily PEPM (lb/day)	942	74.5	2,420	446.8	4,960
Total Annual PEPM (lb/year)	275,445	24,260	311,989	87,721	508,590

1 The value of 15.78 lb/hr was obtained from the current permit.

D. BACT Determination Calculation:

Rule 2201 sets BACT requirements on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. For modifications to an existing emissions unit with a valid Permit to Operate, BACT is required if the Adjusted Increase in Permitted Emissions (AIPE) exceeds 2.0 pounds in any one day. Table 9 depicts the current permitted daily emissions limit and Table 10 shows the post project values.

Table 9. Current Maximum Turbine Daily Emissions (with 100% Duct Burner Firing)

	Startup Emissions (lb/event)	Shutdown Emissions (lb/event)	Max. Emissions (lb/hr @ 100% Load)	Emissions @ Baseload Operation (19.167 hr)	Daily Emission Limit per Unit (lb/day)	Combined DEL for 2 Units (lb/day)
$PM_{10}/PM_{2.5}$	85	35	17.80	341.17	461.2	922.3
SOx	5.94	1.55	1.55	29.71	37.2	74.4
NOx	750	115	15.96	305.91	1,170.9	2,341.8
VOC	85	30	5.51	105.61	220.6	441.2
CO	1,750	325	19.22	368.39	2,443.4	4,886.8

The baseload operation for the current equipment uses data from full load operations with duct burner firing at an ambient temperature of 15ºF.

Table 10. Post Project Maximum Turbine Daily Emissions (with 100% Duct Burner Firing)

	Startup Emissions (lb/event)	Shutdown Emissions (lb/event)	Max. Emissions (lb/hr @ 100% Load)	Emissions @ Baseload Operation (19.167 hr)	Daily Emission Limit per Unit (lb/day)	Combined DEL for 2 Units (lb/day)
$PM_{10}/PM_{2.5}$	85	13.4	17.80	341.17	439.9	879.8
SOx	6.4	1.55	1.58	30.19	38.14	76.28
NOx	314.30	115	16.74	320.76	750.06	1,500.12
VOC	16.33	30	5.84	111.84	158.17	316.34
CO	1,261.20	325	20.38	390.62	1,976.82	3,953.65

The baseload operation for the upgraded equipment is maximum firing with duct burner operation at an ambient temperature of 30°F. Other equipment limitations prohibit full load operation at 15°F for the upgraded CTGs. The data indicate that there are no emissions increases of permitted emissions in excess of 2 lb/day by pollutant of each permit unit. The Project does not trigger a BACT analysis. The CTGs already have emission control equipment for NOx and CO that is consistent with technologically feasible BACT identified in the District BACT Clearinghouse. The VOC control technology emission limit represents achieved in practice BACT but actual VOC concentrations appear to satisfy technologically feasible BACT.

E. Potential to Emit, PE:

Section 3.21 of Rule 2201 defines the potential to emit (PE) as the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. The criteria pollutant potentials to emit for the CTGs are presented below:

Maximum Hourly Emissions for CTGs

The maximum hourly NOx, CO, VOC, SOx, and $PM_{10}/PM_{2.5}$ emissions for the CTGs are shown in Table 11.

Table 11. Combined Worst-Case Hourly Emissions - CTGs

	Maximum Startup Emissions (lb/hr)	Turbine # 1 Emissions (lb/hr)	Turbine #2 Emissions (lb/hr)	Max. Hourly Emissions for Both Turbines (lb/hr)
NOx	82	82	82	164
CO	329	329	329	658
VOC	4.26	4.26	4.26	8.52
SOx	1.67	1.67	1.67	3.34
$PM_{10}/PM_{2.5}$	40.0	40.0	40.0	80

Maximum Daily PE for CTGs

As described in Section VII.A, the maximum daily $PM_{10}/PM_{2.5}$, SOx, NOx, VOC, and CO emissions for each CTG were estimated assuming 100 percent capacity, with 100 percent duct burner firing, at an ambient temperature of 30°F, startup, shutdown and baseload operation.

Table 12. Maximum Turbine Daily Emissions (with 100% Duct Burner Firing)

	Startup Emissions (lb/event)	Shutdown Emissions (lb/event)	Max. Emissions (lb/hr @ 100% Load)	Emissions @ Baseload Operation (19.167 hr)	DEL (per CTG)	Combined DEL for 2 CTGs
$PM_{10}/PM_{2.5}$	85.3	13.4	17.80	341.17	439.9	879.8
SOx	6.4	1.55	1.58	30.19	38.14	76.28
NOx	314.30	115	16.74	320.76	750.06	1,500.12
VOC	16.33	30	5.84	111.84	158.17	316.34
CO	1,261.2	325	20.38	390.6	1,976.8	3,953.7

Maximum Quarterly PE for CTGs

There are a number of possible operating scenarios for the Sunrise facility. This facility operates when demand requires. Sunrise has developed a case which they believe represents the expected worst case emissions. This case is based on the following conditions and uses similar methodology as presented in the 2001 permit application:

1. 182 starts and shutdowns. The elapsed times for events were taken from the 2001 permit application (*Determination of Compliance Evaluation CAPP Application Submittal, July 19, 2001)*.
2. 875 offline hours per year.
3. The number and type of starts and shutdowns per quarter were based on the 2001 permit application and adjusted from 100 starts to 182 starts.
4. The total startup hours per year are 389 and the annual shutting down time totals 182 hours.
5. The duct burner operation was based on the percent per quarter used in the 2001 application. Duct Burner (DB) Fraction = Hours Firing/Total Hours Operation.
6. The normal operating hours per quarter equals the total hours in a quarter minus the combination of startup hours, shutdown hours and offline hours per quarter.
7. Operating hours with DB = Operating hours per quarter times the fraction of time per quarter the DB operates.
8. Operating hours DB unfired = Operating hours per quarter times the fraction of time per quarter unfired.
9. Calculated total operating hours per year = 7,313.
10. Quarter 1 and 4 normal operating emissions based on 30°F ambient temperature.
11. Quarter 2 normal operating emissions calculated with an ambient temperature of 65°F.
12. Quarter 3 normal operating emissions calculated using an ambient temperature of 115°F.

Tables 13 through 20 show the expected quarterly emissions based on the above scenario. Detailed emissions calculations are included Appendix C.

<u>1st Quarter Emissions</u>

Table 13. First Quarter Startup/Shutdown Emissions

	$PM_{10}/PM_{2.5}$ (lb/qtr)	**SOx (lb/qtr)**	**NOx (lb/qtr)**	**VOC (lb/qtr)**	**CO (lb/qtr)**
Startup Emissions	3,751	207	6,613	526	17,911
Number of Hot Starts	16	16	16	16	16
Hot Start Emissions	352	27	448	68	576
Number of Warm Starts	27	27	27	27	27
Warm Start Emissions	2,303	97	2,079	245	940
Number Cold Starts	13	13	13	13	13
Cold Start Emissions	1,096	83	4,086	212	16,396
Shutdown Emissions	750	87	6,440	1,680	18,200
Number of Shutdowns	56	56	56	56	56
Total Startup & Shutdown Emissions	**4,501**	**294**	**13,053**	**2,206**	**36,111**

Table 14. First Quarter Total Emissions

	$PM_{10}/PM_{2.5}$ (lb/qtr)	SOx (lb/qtr)	NOx (lb/qtr)	VOC (lb/qtr)	CO (lb/qtr)
Startup/Shutdown Emissions	4,501	294	13,053	2,206	36,111
Baseload Emissions w/duct firing	20,379	1,803	19,160	6,686	23,333
Baseload Emissions w/o duct firing	7,419	750	7,951	1,577	9,684
Total Quarterly PE (per CTG)	32,300	2,847	40,163	10,469	69,128
Total Combined Quarterly PE (2 CTGs)	**64,599**	**5,695**	**80,327**	**20,938**	**138,256**

2nd Quarter Emissions

Table 15. Second Quarter Startup/Shutdown Emissions

	$PM_{10}/PM_{2.5}$ (lb/qtr)	SOx (lb/qtr)	NOx (lb/qtr)	VOC (lb/qtr)	CO (lb/qtr)
Startup Emissions	3,668	198	6,061	502	15,424
Number of Hot Starts	16	16	16	16	16
Hot Start Emissions	352	27	448	68	576
Number of Warm Starts	28	28	28	28	28
Warm Start Emissions	2,388	101	2,156	254	974
Number Cold Starts	11	11	11	11	11
Cold Start Emissions	927	70	3,457	180	13,873
Shutdown Emissions	737	85	6,325	1,650	17,875
Number of Shutdowns	55	55	55	55	55
Total Startup & Shutdown Emissions	**4,405**	**283**	**12,386**	**2,152**	**33,299**

Table 16. Second Quarter Total Emissions

	$PM_{10}/PM_{2.5}$ (lb/qtr)	SOx (lb/qtr)	NOx (lb/qtr)	VOC (lb/qtr)	CO (lb/qtr)
Startup/Shutdown Emissions	4,405	283	12,386	2,152	33,299
Baseload Emissions w/duct firing	20,573	1,786	18,975	6,615	23,099
Baseload Emissions w/o duct firing	6,907	719	7,619	1,542	9,278
Total Quarterly PE (per CTG)	31,884	2,788	38,981	10,309	65,676
Total Combined Quarterly PE (2 CTGs)	**63,769**	**5,576**	**77,961**	**20,618**	**131,352**

3rd Quarter Emissions

Table 17. Third Quarter Startup/Shutdown Emissions

	$PM_{10}/PM_{2.5}$ (lb/qtr)	SOx (lb/qtr)	NOx (lb/qtr)	VOC (lb/qtr)	CO (lb/qtr)
Startup Emissions	900	42	861	107	529
Number of Hot Starts	6	6	6	6	6
Hot Start Emissions	132	10	168	26	216
Number of Warm Starts	9	9	9	9	9
Warm Start Emissions	768	32	693	82	313
Number Cold Starts	0	0	0	0	0
Cold Start Emissions	0	0	0	0	0
Shutdown Emissions	201	23	1,725	450	4,875
Number of Shutdowns	15	15	15	15	15
Total Startup & Shutdown Emissions	**1,101**	**66**	**2,586**	**557**	**5,404**

Table 18. Third Quarter Total Emissions

	$PM_{10}/PM_{2.5}$ (lb/qtr)	SOx (lb/qtr)	NOx (lb/qtr)	VOC (lb/qtr)	CO (lb/qtr)
Startup/Shutdown Emissions	1,179	66	2,586	557	5,404
Baseload Emissions w/duct firing	32,738	2,805	29,822	10,391	36,311
Baseload Emissions w/o duct firing	2,258	228	2,420	495	2,947
Total Quarterly PE (per CTG)	36,175	3,099	34,827	11,443	46,892
Total Combined Quarterly PE (2 CTGs)	**72,350**	**6,199**	**69,655**	**22,887**	**93,784**

4th Quarter Emissions

Table 19. Fourth Quarter Startup/Shutdown Emissions

	$PM_{10}/PM_{2.5}$ (lb/qtr)	SOx (lb/qtr)	NOx (lb/qtr)	VOC (lb/qtr)	CO (lb/qtr)
Startup Emissions	3,729	205	6,613	526	17,911
Number of Hot Starts	16	16	16	16	16
Hot Start Emissions	352	27	448	68	576
Number of Warm Starts	27	27	27	27	27
Warm Start Emissions	2,303	97	2,079	245	940
Number Cold Starts	13	13	13	13	13
Cold Start Emissions	1,074	82	4,086	212	16,396
Shutdown Emissions	750	87	6,440	1,680	18,200
Number of Shutdowns	56	56	56	56	56
Total Startup & Shutdown Emissions	**4,466**	**291**	**13,053**	**2,206**	**36,111**

Table 20. Fourth Quarter Total Emissions

	$PM_{10}/PM_{2.5}$ (lb/qtr)	SOx (lb/qtr)	NOx (lb/qtr)	VOC (lb/qtr)	CO (lb/qtr)
Startup/Shutdown Emissions)	4,479	292	13,053	2,206	36,111
Baseload Emissions w/duct firing	26,182	2,317	24,615	8,590	29,977
Baseload Emissions w/o duct firing	3,694	374	3,959	785	4,822
Total Quarterly PE (per CTG)	34,355	2,982	41,627	11,581	70,910
Total Combined Quarterly PE (2 CTGs)	**68,711**	**5,965**	**83,254**	**23,162**	**141,819**

Maximum Annual PE

Table 21. Annual Emissions Summary (Gas Turbines)

Quarter	$PM_{10}/PM_{2.5}$	SOx	NOx	VOC	CO
1st (lb)	64,599	5,695	80,327	20,938	138,256
2nd (lb)	63,769	5,576	77,961	20,618	131,352
3rd (lb)	72,350	6,199	69,655	22,887	93,784
4th (lb)	68,711	5,965	83,254	23,162	141,819
Proposed Annual PE (lb)	269,429	23,434	311,197	87,606	505,211
Proposed Annual PE (tons)	**134.71**	**11.72**	**155.60**	**43.80**	**252.61**
Current Annual PE (tons)	**134.83**	**12.13**	**155.67**	**43.84**	**253.99**
Calculated Difference in PE (tons)	**-0.12**	**-0.41**	**-0.07**	**-0.04**	**-1.38**

F. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to Section 4.9 of District Rule 2201, the Pre-Project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. The SSPE1 is shown in the following table.

Table 22. SSPE1

Permit Unit	$PM_{10}/PM_{2.5}$ (lb/year)	SOx (lb/year)	NOx (lb/year)	VOC (lb/year)	CO (lb/year)
S-3746-1-12	134,825	12,129	155,669	43,837	253,989
S-3746-2-12	134,825	12,129	155,669	43,837	253,989
S-3746-3-6	5,760	0	0	0	0
S-3746-4-5	35	1	652	47	612
Total SSPE1	**275,445**	**24,260**	**311,989**	**87,721**	**508,590**

G. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post-Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. The SSPE2 is shown in the following table.

Table 23. SSPE2

Permit Unit	$PM_{10}/PM_{2.5}$ (lb/year)	SOx (lb/year)	NOx (lb/year)	VOC (lb/year)	CO (lb/year)
S-3746-1-13	134,714	11,717	155,598	43,803	252,605
S-3746-2-13	134,714	11,717	155,598	43,803	252,605
S-3746-3-6	5,760	0	0	0	0
S-3746-4-5	35	1	652	47	612
Total SSPE2	**275,223**	**23,435**	**311,849**	**87,653**	**505,823**

H. Increase in Permitted Emissions (IPE) Calculations – BACT Applicability

As shown in Table 21, the proposed project will not result in an increase in permitted emissions for $PM_{10}/PM_{2.5}$, SOx, NOx, VOC and CO. Therefore, BACT is not required for these pollutants. Although BACT is not required, the CTGs have control equipment that is consistent with technologically feasible BACT for CO and NOx identified in the District BACT Clearinghouse and achieve in practice BACT for VOC and PM_{10}. Actual performance for VOC is representative of technologically feasible BACT.

I. Major Stationary Source Determination

Calculations were performed separately for each pollutant. All calculations were performed on an annual basis using pounds per year of permitted emissions. A major source is a stationary source with a potential to emit of 20,000 pounds or more per year of VOC's or NOx, or 200,000 pounds or more per year of CO, or 140,000 pounds or more per year of $PM_{10}/PM_{2.5}$ or SOx.

The major stationary source determination is shown in the table below. As shown in the table below, the Sunrise facility exceeds the major source thresholds for $PM_{10}/PM_{2.5}$, NOx, VOC and CO. Therefore, the Sunrise facility will continue to be a major source for these pollutants.

Table 24. Major Stationary Source Calculation

Permit Unit	$PM_{10}/PM_{2.5}$ (lb/year)	SOx (lb/year)	NOx (lb/year)	VOC (lb/year)	CO (lb/year)
S-3746-1-13	134,714	11,717	155,598	43,803	252,605
S-3746-2-13	134,714	11,717	155,598	43,803	252,605
S-3746-3-6	5,760	0	0	0	0
S-3746-4-5	35	1	652	47	612
Total SSPE2	**275,223**	**23,435**	**311,849**	**87,653**	**505,823**
Major Source Threshold (lb/yr)	**140,000**	**140,000**	**20,000**	**20,000**	**200,000**
Post-Project: Major Source?	**Yes**	**No**	**Yes**	**Yes**	**Yes**

J. Offset Quantity Calculations

No offsets are required as the proposed project will not result in an emissions increase of any air contaminant that exceeds the major source threshold.

VIII. COMPLIANCE

District Rule 1070 Inspections

This rule authorizes the District to impose record keeping requirements, to make inspections, and to require source testing necessary in determining whether air pollution sources are in compliance with applicable rules and regulations. Provisions included in the operating permit are consistent with the requirements of this rule. Therefore, ongoing compliance with this rule is satisfied.

District Rule 1080 Stack Monitoring

This rule grants the Air Pollution Control Officer (APCO) the authority to request the installation and use of CEMs, and specifies performance standards for the equipment and administrative requirements for record keeping, reporting, and notification. The facility is equipped with operational CEMs, and provisions contained in the operating permits are consistent with the requirements of this rule. Therefore, ongoing compliance with this rule is expected.

District Rule 1081 Source Sampling

This rule requires adequate and safe facilities for using in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection. The current permit conditions are consistent with the requirements of this rule. Ongoing compliance with this rule is expected.

District Rule 1100 Equipment Breakdown

This rule defines a breakdown condition and the procedures to follow if one occurs, including requirements for corrective action, the issuance of an emergency variance and the reporting. The requirements of this rule are included in the current permit. Ongoing compliance with this rule is expected.

District Rule 2010 Permits Required

This rule requires submittal of an application for the construction, alteration, replacement, or operation of a source which emits air contaminants. Submission of this application package satisfies the requirements of this rule.

District Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in a SB288 Major Modification or a Federal Major Modification, as defined in Rule 2201.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

a. New emissions units – PE > 2 lb/day

As discussed in Section I above, there are no new emission units associated with this proposed project. Therefore, BACT is not triggered for new emissions units with a PE > 2 lb/day.

b. Relocation of emissions units – PE > 2 lb/day

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered for relocation of an emissions unit with a PE > 2 lb/day.

c. Modification of emissions units – Adjusted Increase in Permitted Emissions (AIPE) > 2 lb/day

The AIPE is determined by subtracting the emissions unit's Historically Adjusted Potential to Emit (HAPE) in pounds per day from the new potential to emit (PE2) also in pounds per day. HAPE is equal to the pre-project potential to emit (PE1) times the ratio of the new permitted emission factor (EF2) and the pre-project permitted emission factor (EF1). If EF2 is greater than EF1 the ratio is set to 1.

As discussed in Section I above, there are no modified emissions units with an AIPE > 2 lb/day; therefore BACT is not triggered for modification of emission units with an AIPE > 2 lb/day.

d. Major Modification

Section 3.18 defines a federal major modification as the same as "Major Modification" in 40 CFR 51.165 and Part D of Title I of the Clean Air Act (CAA). SB 288 Major Modifications are not federal major modifications if criteria of one of the exclusions are met. The exclusions are for "less than significant emissions increases". Table 3-1 presents the significance thresholds for selected pollutants. The significance thresholds for VOC and NOx are zero lb/yr. Therefore, any annual increase in VOC or NOx would be considered significant. There are no projected annual emissions increases in any pollutants listed in Table 3-1. Section 3.36 describes SB 288 Major Modifications. An SB 288 Major Modification is a major modification as defined in 40 CFR Part 51.165 (as in effect on December 19, 2002) and part D of Title I of the CAA (as in effect on December 19, 2002). For the purposes of this definition, the SB 288 major modification thresholds for existing major sources are 50,000 lb/yr for VOC and NOx, 30,000 lb/yr for PM_{10} and 80,000 lb/yr for SOx. There are no annual emissions increases for any pollutants listed in Table 3-4 of the rule.

This project does not constitute a SB 288 Major Modification or Federal Major Modification; therefore, BACT is not triggered for major modification purposes.

Although BACT is not required for the proposed project, the CTGs meet District BACT requirements for PM_{10}/$PM_{2.5}$, SOx, NOx, VOC and CO as summarized below:

PM_{10}/$PM_{2.5}$: Air inlet cooler/filter, lube oil vent coalescer to achieve less than 5% opacity visible emissions at lube oil vents, and natural gas as fuel.

SOx: Natural gas fuel, consisting primarily of methane, with a sulfur content of less than 0.25 gr. S/100 dscf

NOx: 2.0 ppmvd @ 15% O_2 (1 hr average) - except during startup/shutdown, dry low NOx combustors, SCR with ammonia injection, & natural gas fuel

VOC: 2.0 ppmvd @ 15% O_2 (3 hr rolling average) - except during startup/shutdown, achieved with dry low-NOx combustors and oxidation catalyst

CO: 4 ppmvd @ 15% O2 (3 hr rolling average) - except during startup/shutdown, achieved with dry low-NOx combustors and oxidation catalyst.

B. Offsets

1. Offset Applicability

No offsets are required as the proposed project will not result in an emissions increase for PM_{10}/$PM_{2.5}$, SOx, NOx, VOC and CO.

C. Public Notification

1. Applicability

Public noticing is required for:

a. Any new Major Source, which is a new facility that is also a Major Source,
b. Major Modifications,
c. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
d. Any project which results in the offset thresholds being surpassed, and/or
e. Any project with a Stationary Source Increase in Permitted Emissions (SSIPE) of greater than 20,000 lb/year for any pollutant.

a. New Major Source

New Major Sources are new facilities, which are also Major Sources. Since this is not a new facility, public noticing is not required for this project for New Major Source purposes.

b. Major Modification

This project does not constitute a SB 288 and a Federal Major Modification; therefore, public noticing for Major Modification purposes is not required.

c. PE > 100 lb/day

Applications which include a new emissions unit with a PE greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. There are no new emissions units which will have daily emissions greater than 100 lb/day for any pollutant associated with this project; therefore, public noticing is not required by this section.

d. Offset Threshold

The facility already exceeds the offset thresholds for $PM_{10}/PM_{2.5}$, NOx, VOC and CO; therefore this project will not result in a source having emissions below the thresholds to a level above the thresholds after the modification.

Therefore, public noticing is not triggered for crossing the offset thresholds.

e. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant.

The proposed project will not result in a SSIPE of more than 20,000 lb/year for any affected pollutant. Therefore, public noticing is not triggered for this section.

2. Public Notice Action

As discussed above, public notice will not be required for this project.

D. Daily Emission Limits (DELs)

The DELs for the CTGs are specified in the existing permit. Sunrise is proposing to change the DEL for SOx from 37.2 lb/day to 38.1 lb/day.

The revised condition is provided below in strikeout/underscore format:

- *Emissions from each CTG shall not exceed any of the following limits: NOx: 2.0 ppmvd @ 15% O2 or 1,170.9 lb/day; PM10: 461.2 lb/day; CO: 4 ppmvd @ 15% O2 or 2,443.4 lb/day; SOx: ~~37.2~~ 38.1 lb/day or VOC: 2.0 ppmvd @ 15% O2 or 220.6 lb/day. [District NSR Rule]*

The DEL condition for both CTGs requires revision for SOx as well. The proposed condition is as follows:

- *Emission rates from both CTGs (S-3746-1 and -2) shall not exceed any of the following: PM10 - 922.3 lb/day, SOx (as SO_2) - ~~74.4~~ 76.3 lb/day, NOx (as NO_2) - 2,341.8 lb/day, VOC - 441 .2 lb/day, and CO - 4,886.8 lb/day*.

E. Compliance Assurance

1. Source Testing

The current permit includes permit conditions to address source testing requirements for the CTGs. Sunrise is not proposing changes to these source testing requirements. The source testing requirements in the current permit are shown below.

- While dormant, normal source testing shall not be required.
- Upon recommencing operation of this unit, normal source testing shall resume.
- Any source testing required by this permit shall be performed within 60 days of recommencing operation of this unit, regardless of whether the unit remains active or is again designated as dormant.

2. Monitoring

Each CTG/HRSG has a separate exhaust stack. Each unit is equipped with operational continuous emissions monitors (CEMs) for NOx, CO and O_2. The CEMs have two ranges to allow accurate measurements of NOx and CO emissions during startup and shutdown episodes. The CEMs must meet the installation, performance, relative accuracy and quality assurance requirements specified in 40 CFR 60.13 and the acid rain requirements in 40 CFR 75. Continued compliance is expected.

3. Recordkeeping

The current permit includes permit conditions to address recordkeeping requirements for the CTGs. Sunrise is not proposing changes to these recordkeeping requirements. The recordkeeping requirements in the current permit are shown below.

- Records of all dates and times that this unit is designated as dormant or active, and copies of all corresponding notices to the District, shall be maintained, retained for a period of at least five years, and made available for District inspection upon request.
- The permittee shall maintain hourly records of NOx, CO, and ammonia emission concentrations (ppmvd@ 15% O_2), and hourly, daily, and twelve month rolling average records of NOx and CO emissions.

- The permittee shall maintain records of SOx lb/hr, lb/day, and lb/twelve month rolling average emission. SOx emissions shall be based on fuel use records, natural gas sulfur content, and mass balance calculations.

- The owner or operator shall maintain records that contain the following: the occurrence and duration of any start-up, shutdown or malfunction, performance testing, evaluations, calibrations, checks, adjustments, any periods during which a continuous monitoring system or monitoring device is inoperative, maintenance of any CEM system that has been installed pursuant to District Rule 1080 (as amended 12/17/92), and emission measurements.

- All records required to be maintained by this permit shall be maintained for a period of five years and shall be made readily available for District inspection upon request.

- The owners and operators of each affected unit at the source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority; (ii) All emissions monitoring information, in accordance with 40 CFR Part 75; (iii) Copies of all reports, compliance certifications and other submissions and all records made or required under the Acid Rain Program; (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission that demonstrates compliance with the requirements of the Acid Rain Program.

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

F. Ambient Air Quality Analysis

Section 4.14.1 of this Rule requires that an ambient air quality analysis (AAQA) be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard.

In accordance with Rule 2201, Section 4.14.1.1, a new or modified source which is not subject to the public noticing requirements of Section 5.4 is exempt from the requirements of Section 4.14.1, AAQA. The proposed project is not subject to the public noticing requirements of Section 5.4. Therefore, an AAQA for the proposed project is not required.

G. Federal Major Modification Certification of Compliance

The federal major modification compliance certification is required for any project, which constitutes a New Major Source or a Federal Major Modification. The proposed project does not constitute a New Major Source or a Federal Major Modification. Therefore, the federal major modification certification of compliance is not required.

District Rule 2410 Prevention of Significant Deterioration

This Rule is applicable to any source and the owner or operator of any source subject to any requirement under 40 CFR Part 52.21. The proposed project does not result in a significant net emissions increase of an air contaminant for which the area is designated attainment. Therefore, Rule 2410 is not applicable and no further analysis is required.

District Rule 2520 Federally Mandated Operating Permits

This facility is subject to this Rule, and has received their Title V Operating Permit. Sunrise is submitting this permit application for the proposed modification of the CTGs. The proposed project is considered a minor permit modification under Rule 2520. Compliance with this rule is expected.

District Rule 2540 Acid Rain Program

The CTGs are subject to the acid rain program that is implemented through the Title V operating permit. The acid rain program requirements for this facility are relatively minimal. Monitoring of the NOx and SOx emissions and a relatively small quantity of SOx allowances are required as well as the use of a NOx CEM. Compliance with this rule is expected.

District Rule 4001 New Source Performance Standards

40 CFR Part 60, Subpart GG

The CTGs at the existing power plant are subject to Subpart GG which limits oxides of nitrogen and sulfur from stationary gas turbines. The applicable NOx limit specified in section 60.332 (a)(1), one hour average, is as follows:

NOx % by volume @ 15% O_2 = 0.0075 * 14.4/Y + F

Y = manufacturers rated heat rate at rated peak load (kJ/watt hour), or actual measured heat rate at LHV and peak load. Y shall not exceed 14.4 kJ/watt hour.

F = NOx emission allowance for fuel bound nitrogen. Natural gas typically has no fuel bound nitrogen, so F is set equal to 0.

Please note that the NSPS NOx standard occurs at the maximum heat rate (depending on ambient temperature) at full load.

NSPS NOx limit:

Y = max heat rate @ LHV = 10,046 Btu/kW hr (peak load @ 115°F)
= 10.046 Btu/W hr * 1.0542 kJ/Btu
Y = 10.59 kJ/W hr (less than 14.4 kJ/W hr)

NOx % by vol. @ 15% O_2 = 0.0075 * 14.4/10.59 + 0
= 0.0102 = 102 ppmvd @15% O_2

The CTGs will continue to operate at a BACT NOx level of 2.0 ppmvd @ 15% O_2, except during startup and shutdown, on a one-hour rolling average. Compliance with the Subpart GG NOx standard (one-hour average) is expected.

The applicable SOx limits specified in section 60.333 are as follows:

SOx = 0.015% by vol. @ 15% O_2
= 150 ppmvd @ 15% O_2

or fuel S ≤ 0.8% by weight

SOx emissions are based on combusting utility quality natural gas with a fuel sulfur content of 0.25 gr/100 scf. This fuel sulfur content is equivalent to 6.4 ppm by weight or a weight percent of 0.00064 percent.

Both SOx emissions and fuel sulfur content are less than that required by Subpart GG. Recordkeeping and reporting of the fuel sulfur content is required. Reporting will continue to be performed using an alternative custom reporting schedule. Because the CTGs do not use water injection, monitoring of water injection rate is not applicable and not required.

Reporting and notifications are required as specified in 40 CFR, Subpart A. Subpart GG will not apply after the CTG upgrades. The modified units will be subject to 40 CFR Part 60, Subpart KKKK.

40 CFR Part 60, Subpart KKKK

40 CFR Part 60, Subpart KKKK covers the Standards of Performance for Stationary Combustion Turbines which commenced construction, modification, or reconstruction after February 18, 2005. §60.14 defines a modification as any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies. There are some exclusions. However, the proposed project would appear to be subject to Subpart KKKK. This NSPS sets NOx concentration limits and allows the use of CEMs for compliance. The CTGs exhaust to SCR units with a residual NOx concentration of no more than 2.0 ppmvd @ 15% O_2. This concentration is well below the standards presented in Table 1 of the Subpart. Sunrise already uses CEMs for compliance purposes. The NSPS also limits SOx emissions to no more than 0.060 lb SO_2/MMBtu. These turbines and duct burners combust pipeline quality natural gas and compliance is achieved.

The NSPS requires units with SCR to continuously monitor “appropriate parameters” to verify proper operation. The current permits contain conditions to monitor appropriate parameters. These conditions will remain in the ATC and new PTOs.

District Rule 4102 Nuisance

The facility is located in a sparsely populated oilfield, approximately 1.3 miles SW of the junction of State Route 33 and Shale Road, 3 miles northwest of Fellows, CA and 2.5 miles south of Derby Acres, CA. Nuisance complaints are not expected from properly operated combustion equipment fired exclusively on low-sulfur natural gas; therefore, operation of the CTGs is not expected to result in nuisance complaints.

California Health and Safety Code, Section 41700

The District’s Risk Management Policy requires an evaluation of the risk associated with increases in hazardous air pollutants. Pursuant to the definition of Section V.A. of this policy, a hazardous pollutant is “...a substance included in lists prepared by the California Air Resources Board pursuant to Section 44321 of the California Health and Safety Code that has an Office of Environmental Health Hazard Assessment (OEHHA) approved heath risk value.” The proposed project will not result in an increase of potentially hazardous air pollutants; therefore, an evaluation of the associated health risk is not required.

District Rule 4201 Particulate Matter Concentration

Rule 4201 limits PM emissions from any source operation to 0.1 gr/dscf (standard conditions are 60°F and 1 atmosphere pressure).

The PM exhaust concentration for the CTGs was determined at a worst-case condition. The worst-case condition is 100% load and 30°F. All PM emitted is expected to be 10 microns or smaller.

Summary of PM gr/scf:

PM Emissions = 17.8 lb/hr
H_2O = 9.48%
Exhaust Gas Flow, scfm (wet) = 806,500
Exhaust Gas Flow, dscfm = 806,500 * [(100-9.48)/100] = 730,044

Grain Loading = (17.8 lb/hr x 1 hour/60 min x 7000 grains/lb) / 730,044 scfm = 0.0028 gr/dscf

As shown above, PM emissions for the CTGs will be less than 0.1 gr/dscf. Compliance is expected.

District Rule 4202 Particulate Matter Emission Rate

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr. Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to the CTG's.

District Rule 4301 Fuel Burning Equipment

Rule 4301 limits air contaminant emissions from fuel burning equipment as defined in the rule. Section 3.1 defines fuel burning equipment as "any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer".

The CTG/HRSGs fail to meet the Rule 4301 definition of fuel burning equipment because they primarily (both initially and chiefly) produce power mechanically, i.e. the products of combustion pass across the power turbine blades which causes the turbine shaft to rotate, and not through indirect heat transfer. The turbine shaft is coupled to an electrical generator shaft which is rotated to produce electricity.

Because the CTGs primarily produce power by mechanical means, it does not meet the definition of fuel burning equipment. Rule 4301 does not apply to the affected equipment.

District Rule 4703 Stationary Gas Turbines

Rule 4703 limits NOx and CO emissions from stationary gas turbines. For CTG's rated greater than 10 MW with SCR, the NOx and CO emission limits (three-hour rolling average) are:

NOx ppmvd @ 15% O_2 for CTG, with SCR = 9 x (EFF/25)

Where EFF is the higher of EFF1 or EFF2.

EFF1 is the demonstrated percent efficiency of the gas turbine at peak load for that facility, calculated as follows:

EFF1 = 3412 Btu/kW hr / actual heat rate @ HHV Btu/kW hr) x 100%

And

EFF2 is the EFFmfr, which is the manufacturer's continuous rated percent efficiency with air pollution control equipment at LHV, converted to HHV.

EFF2 = EFFmfr x (LHV/HHV),

where the typical LHV/HHV ratio for natural gas = 0.9

EFF1 must be demonstrated for the proposed modified turbine once it is operated. EFF1 results in a slightly higher allowable NOx emission rate if the CTG operates more efficiently than the manufacturer's continuous rated percent efficiency.

The manufacturer's percent efficiency will be based on a peak load (100%) of 9,584 Btu/kW-hr, which occurs at 115ºF, and is calculated as follows:

Manufacturer's heat rate = 9,584 Btu/kW-hr @ LHV/(0.9 LHV/HHV)
= 10,649 Btu/kW-hr @ HHV

EFF2 = (3412 Btu/kW hr / 10,649 Btu/kW-hr @ HHV) x 100%
= 32%

SCR NOx Limit = 9 x (30.57/25)
= 11.5 ppmvd @ 15% O_2

During normal operation, the CTGs will have a NOx emission rate of 2.0 ppmvd @ 15% O_2, which is well below the limit allowed by Rule 4703.

CO emission limits are as follows:

General Electric Frame 7: 25 ppmvd @ 15% O_2

The CTGs have a CO emission rate of 4 ppmvd @ 15% O_2 (3-hour average), except during startup and shutdown. This is lower than the 25 ppmvd allowed by Rule 4703.

Rule 4703 requires that the operator install equipment that monitors the control system operating parameters, the elapsed time of operation, and a NOx CEM that meets the requirements in 40 CFR Part 60 Appendix 6, Spec 2 and the operator to maintain such records for at least two years. Prior to issuance of the Permit to Operate, Sunrise must submit information that correlates the control system operating parameters to the NOx emission rate, to be used when the CEM is down or not operating properly, as required by section 6.2.5 of Rule 4703.

Sunrise must maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local time, start-up and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used as required by Rule 4703 section 6.2.6. This information shall be available for inspection at any time for two years from the date of entry.

Sunrise must demonstrate compliance annually with the NOx and CO emission limits and determine the demonstrated percent efficiency (EFF) of the stationary gas turbine, using the following test methods:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.
- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.
- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.
- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

Demonstrated percent efficiency of the stationary gas turbine shall be determined using the facility instrumentation for gas turbine fuel consumption and power output. Power output values used to determine gas turbine efficiency shall be the electrical power output of the gas turbine. Compliance with this rule is expected.

District Rule 4801 Sulfur Compounds

Rule 4801 limits sulfur compound emissions to 0.2% (2,000 ppm) dry volume. The CTG SOx emissions are based on combusting natural gas consisting principally of methane with a fuel S content of 0.25 gr/100 scf and a heating value of 1041 Btu/scf. This fuel sulfur content results in a SOx emission concentration of 11 ppmvd @ 15% O_2. Therefore, SOx emissions are not expected to exceed 2,000 ppmvd, and compliance with this rule is expected.

California Health and Safe Code, Section 44300 Air Toxic "Hot Spots"

Section 44300 of the California Health and Safety Code requires submittal of an air toxics "Hot Spot" information and assessment report for sources with criteria pollutant emissions greater than 10 tons per year. The proposed project will not result in an increase in criteria pollutant or toxic air contaminant emissions. Therefore, a health risk assessment (HRA) is not required for the proposed project.

Enforcement - Summary of Testing and Monitoring Requirements

For the CTGs initial compliance source testing for $PM_{10}/PM_{2.5}$, NOx, VOC, and CO will be performed within 60 days of initial operation of the proposed modified CTGs. Annual compliance source testing for $PM_{10}/PM_{2.5}$, NOx, VOC, and CO will be required thereafter. Periodic compliance demonstration with the fuel gas sulfur content limit will be required as allowed in 40 CFR 60 Subpart GG (New Source Performance Standards for Gas Turbine

Engines), 40 CFR Part 60 Subpart KKKK (Standards Of Performance For Stationary Combustion Turbines) and 40 CFR 75 (Continuous Emission Monitoring).

Each CTG has a separate exhaust stack. The units are equipped with CEMs for NOx, CO, and O_2. Each CTG is equipped with an individual CEM. Each CEM has two ranges to allow accurate measurements of NOx and CO emissions during startup. The CEMs must meet the installation, performance, relative accuracy, and quality assurance requirements specified in 40 CFR 60.13 and Appendix B (referenced in the CEM requirements of Rule 4703) and in 40 CFR part 75.

An initial source test for NOx and CO during startup of one CTG will be required initially and then every seven years thereafter. This testing will serve two purposes, to validate the startup emission estimates used in the emission calculations and to verify that the CEMs accurately measure startup emissions.

IX. RECOMMENDATION:

Issue the ATCs and Final Determination of Compliance for the proposed modification of the CTGs.

X. BILLING INFORMATION:

The applicant has submitted an application filing fee of $87 for each proposed permit unit modification. Each permit subject to District Rule 2520 (Federally Mandated Operating Permits) is also assessed a fee of $23 per emissions unit. Additional fees are required for processing of the applications by the SJVAPCD per Section 3.0 of Rule 3010.

The Permit to Operate annual fees will be based on the fee schedules and ratings shown below. These SJVAPCD bills these annually and they are not required to be included with the application.

Permit Unit	Rating	Fee Schedule	Annual Fee
S-3746-1-13	190 MW	3020-08 B	$15,843
S-3746-2-13	190 MW	3020-08 B	$15,843

APPENDIX

A: Proposed Permit Conditions
B: Site Vicinity Map
C: CTG Emissions Calculations

APPENDIX A

Proposed Permit Conditions

PROPOSED PERMIT CONDITIONS

This section provides the suggested permit conditions for the proposed project. Changes to existing conditions are depicted in strikeout/underscore.

Permit Unit S-3746-1-13: ~~160 MW~~ <u>190 MW</u> NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF GENERAL ELECTRIC FRAME 7FA NATURAL GAS-.FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW-NOX COMBUSTORS, HEAT RECOVERY STEAM GENERATOR WITH DUCT FIRING, SCR, AND OXIDATION CATALYSTS (~~585~~ <u>635</u> MW TOTAL PLANT NOMINAL RATING)

1. While dormant, the fuel line shall be physically disconnected from the unit. [District Rule 2080]

2. Permittee shall submit written notification to the District upon designating the unit as dormant or active. [District Rule 2080]

3. While dormant, normal source testing shall not be required. [District Rule 2080]

4. Upon recommencing operation of this unit, normal source testing shall resume. [District Rule 2080]

5. Any source testing required by this permit shall be performed within 60 days of recommencing operation of this unit, regardless of whether the unit remains active or is again designated as dormant. [District Rule 2080]

6. Records of all dates and times that this unit is designated as dormant or active, and copies of all corresponding notices to the District, shall be maintained, retained for a period of at least five years, and made available for District inspection upon request. [District Rule 1070]

7. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators to maintain visible emissions from lube oil vents no greater than 5% opacity, except for three minutes in any hour. [District NSR Rule] Federally Enforceable Through Title V Permit

8. CTG shall be equipped with continuously recording fuel gas flowmeter. [District NSR Rule] Federally Enforceable Through Title V Permit

9. CTG exhaust after the SCR unit shall be equipped with continuously recording emissions monitors dedicated to this unit for NOx, CO, and O2. Continuous emissions monitors shall meet the requirements of 40 CFR Part 60, Appendices Band F, and 40 CFR Part 75, and shall be capable of monitoring emissions during startups and shutdowns as well as normal operating conditions. If relative accuracy of CEM(s) cannot be demonstrated during startup conditions, CEM results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits. [40 CFR ~~60.334(c)~~ <u>60.4340(b),</u> District Rules 1080, 2201 and 4703, 40 CFR 64, and PSD SJ 01-01] Federally Enforceable Through Title V Permit

10. CTG shall be equipped with a continuously recording emission monitor preceding the SCR module measuring NOx concentration for the purposes of calculating ammonia slip. Permittee shall check, record, and quantify the calibration drift (CD) at two concentration values at least once daily (approximately 24 hours). The calibration shall be adjusted whenever the daily zero or high-level CD exceeds 5%. If either the zero or high-level CD exceeds 5% for five consecutive daily periods, the analyzer shall be deemed out-of-control. If either the zero or high-level CD exceeds 10% during any CD check, analyzer shall be deemed out-of-control. If the analyzer is out-of-control, the permittee shall take appropriate corrective action and then repeat the CD check. [District NSR Rule, and 40 CFR 64] Federally Enforceable Through Title V Permit

11. The facility shall maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080] Federally Enforceable Through Title V Permit

12. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080] Federally Enforceable Through Title V Permit

13. The owner or operator shall be required to conform to the compliance testing and sampling procedures described in District Rule 1081 (as amended 12/16/93). [District Rule 1081] Federally Enforceable Through Title V Permit

14. CEM cycling times shall be those specified in 40 CFR, Part 51, Appendix P, Sections 3.4, 3.4.1 and 3.4.2, or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080, and 40 CFR 64] Federally Enforceable Through Title V Permit

15. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1081] Federally Enforceable Through Title V Permit

16. Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080] Federally Enforceable Through Title V Permit

17. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080] Federally Enforceable Through Title V Permit

18. The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080] Federally Enforceable Through Title V Permit

19. Operators of CEM systems installed at the direction of the APCO shall submit a written report for each calendar quarter to the APCO and EPA (Attn: AIR-5). The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess emissions, nature and cause of excess (if known}, corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred; And reports on opacity monitors giving the number of three minute periods during which the average opacity exceeded the standard for each hour of operation. The averaged may be obtained by integration over the averaging period or by arithmetically averaging a minimum of four equally spaced instantaneous opacity measurements per minute. Any time exempted shall be considered before determining the excess averages of opacity. [40 CFR 64, District Rule 1080 and PSD SJ O 1 - 0 1] Federally Enforceable Through Title V Permit

20. An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NOX emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NOX emission rate" is the arithmetic average of the average NOX emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NOX emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NOX emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NOX emission rate" is the arithmetic average of all hourly NOX emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NOX emissions rates for the preceding 30 unit operating days if a valid NOX emission rate is obtained for at least 75 percent of all operating hour. ~~An hour of excess emissions shall be defined as any operating hour in which 4-hour rolling average NOx concentration exceeds applicable emissions limit in §60.332(a)(l}, and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NOx, CO or O2. The 4-hour rolling average is the arithmetic average of the average NOx concentration measured by the CEMS for a given hour (corrected to 15 percent O2) and the three unit operating hour average NOx concentrations immediately preceding that unit operating hour.~~ [40 CFR 64 and 40 CFR ~~60.334(j)(l)(iii)~~60.4380(b)(1)] Federally Enforceable Through Title V Permit

21. The owner or operator shall submit reports of NOx excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c) on a semiannual basis. Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction~~, for any 4-consecutive rolling average that exceeds the NOx limit under 40 CFR 60.332(a)(l).~~ For the

purpose of reports required under 40 CFR 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined in 40 CFR ~~60.3340~~ 60.4380. All reports· required under 40 CFR 60.7(c) shall be postmarked by the 30th day following the end of each six-month period. [40 CFR ~~60.3340~~ 60.4395, ~~40 CFR 60.334 (j)(5)~~and District Rule 4703] Federally Enforceable Through Title V Permit

22. If the total duration of NOx excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CEMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form in §60.7(d) shall be submitted and the excess emission report described in §60.7(c) need not be submitted unless requested by the EPA or the Air District. [40 CFR ~~60.334~~ 60.4345), and 40 CFR 60.7(c) and (d)] Federally Enforceable Through Title V Permit

23. Ammonia injection grid shall be equipped with operational ammonia flowmeter and injection pressure indicator. [District NSR Rule] Federally Enforceable Through Title V Permit

24. Permittee shall monitor and record exhaust gas temperature at selective catalytic reduction and oxidation catalyst inlets. [District NSR Rule] Federally Enforceable Through Title V Permit

25. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit

26. CTG shall be fired exclusively on natural gas, consisting primarily of methane and ethane, with a sulfur content no greater than 0.25 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [40 CFR ~~60.333(b)~~ 60.4330(a)(2), District NSR Rule, PSD SJ 01-01] Federally Enforceable Through Title V Permit

27. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored weekly using ASTM Methods 04084, 05504, 06228, or Gas Processors Association Standard 2377. If sulfur content is less than 0.25 gr/100 scf for 8 consecutive weeks, then the Monitoring frequency shall be every six (6) months. If any six (6) month monitoring show an exceedance, weekly monitoring shall resume. [40 ~~CFR 60.334(h)(1) & (3)~~ 60.4360 and District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit

28. Sulfur compound emissions shall not exceed 0.015% by volume at 15% oxygen, on a dry basis averaged over 15 consecutive minutes. [~~40 CFR 60.333(a);~~ County Rule 407 (Kern)] Federally Enforceable Through Title V Permit

29. Startup is defined as the period beginning with turbine initial firing. Shutdown is defined by the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Startup and shutdown durations shall not exceed 60 minutes for a hot startup, 128 minutes for a warm startup, and 230 minutes for a cold startup, and one hour for a shutdown, per occurrence. [District Rules 2201, 4001 & 4703, and PSD SJ 01-01] Federally Enforceable Through Title V Permit

30. ~~Reduced load period is defined as the time during which a gas turbine is operated at less than rated capacity in order to change the position of the exhaust gas diverter gate. Each reduced load period shall not exceed one hour. [District Rule 4703] Federally Enforceable Through Title V Permit~~

31. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703] Federally Enforceable Through Title V Permit

32. The owner or operator shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when the CEMS is not operating properly. [District Rule 4703] Federally Enforceable Through Title V Permit

33. The HHV and LHV of the fuel combusted shall be determined using ASTM 03588, ASTM 1826, or ASTM 1945. [~~40 CFR 60.332(a) and (b) and~~ District Rule 4703] Federally Enforceable Through Title V Permit

34. An owner or operator of any gas turbine with an intermittently operated auxiliary burner shall demonstrate compliance with the auxiliary burner both on and off. [~~40 CFR 60.335(b)(3) and~~ 40 CFR 60.4400 and District Rule 4703] Federally Enforceable Through Title V Permit

35. Ammonia shall be injected when the selective catalytic reduction system catalyst temperature exceeds 500 degrees F. Permittee shall monitor and record catalyst temperature during periods of startup. [District NSR Rule] Federally Enforceable Through Title V Permit

36. During startup or shutdown of any gas turbine engine(s), combined emissions from both gas turbine engines (S-3746-1 and -2) heat recovery steam generator exhausts shall not exceed any of the following: NOx (as NO2) - 700 lb and CO -1,580 lb, in any one hour. If any CTG is in either startup or shutdown mode during any portion of a clock hour, the facility will be subject to the aforementioned limits during that clock hour. [District NSR Rule] Federally Enforceable Through Title V Permit

37. Emission rates from each CTG, except during startup and/or shutdown, shall not exceed any of the following: PM10 -17.8 lb/hr, SOx (as SO2) – ~~1.55~~ 1.58 lb/hr, NOx (as NO2) - ~~15.96~~ 16.74 lb/hr and 2.0 ppmvd@ 15% O2, VOC - ~~5.51~~ 5.84 lb/hr and 2.0 ppmvd@ 15% O2, CO - ~~19.22~~ 20.38 lb/hr and 4 ppmvd@ 15% O2, ammonia - 10 ppmvd@ 15%O2. NOx (as NO2) ppmvd and lb/hr limits are a one-hour rolling average. Ammonia emission limit is a twenty-four hour rolling average. All other ppmvd and lb/hr limits are three-hour rolling averages. If a CTG is in either startup or shutdown mode during any portion of a clock hour, that unit will not be subject to the aforementioned limits during that clock hour. [40 CFR ~~60.332(a)(1)~~ 60.4320(a), District Rules 2201, 4001, 4703, and PSD SJ 01-01] Federally Enforceable Through Title V Permit

38. Emission rates from each CTG shall not exceed any of the following: PM10 - 461.2 lb/day, SOx (as SO2) - ~~37.2~~ 38.1 lb/day, NOx (as NO2) – 1,170.9 lb/day, VOC - 220.6 lb/day, and CO - 2,443.4 lb/day. [District NSR Rule] Federally Enforceable Through Title V Permit

39. Emission rates from both CTGs (S-3746-1 and -2) shall not exceed any of the following: PM10 - 922.3 lb/day, SOx (as SO2) - ~~74.4~~ 76.3 lb/day, NOx (as NO2) - 2,341.8 lb/day, VOC – 441.2 lb/day, and CO - 4,886.8 lb/day. [District NSR Rule and PSD SJ 01-01] Federally Enforceable Through Title V Permit

40. Annual emissions from both CTGs calculated on a twelve consecutive month rolling basis shall not exceed any of the following: PM10 - 269,651 lb/year, SOx (as SO2) - 24,259 lb/year, NOx (as NO2) - 311,337 lb/year, VOC - 87,674 lb/year, and CO - 507,978 lb/year. [District NSR Rule and PSD SJ 01-01] Federally Enforceable Through Title V Permit

41. Each one-hour period in a one-hour rolling average will commence on the hour. Each one-hour period in a three-hour rolling average will commence on the hour. The three-hour average will be compiled from the three most recent one hour periods. Each one-hour period in a twenty-four-hour average for ammonia slip will commence on the hour. The twenty-four-hour average will be calculated starting and ending at twelve-midnight. [District NSR Rule and PSD SJ 01 - 01] Federally Enforceable Through Title V Permit

42. Daily emissions will be compiled for a twenty-four period starting and ending at twelve-midnight. Each calendar month in a twelve-consecutive-month rolling emissions will commence at the beginning of the first day of the month. The twelve-consecutive-month rolling emissions total to determine compliance with annual emissions will be compiled from the twelve most recent calendar months. [District NSR Rule and PSD SJ 01-01] Federally Enforceable Through Title V Permit

43. Ammonia slip limit shall be measured using the following calculation procedure: ammonia slip ppmvd @ 15% O2 = ((a-(bxc/1,000,000)) x 1,000,000 / b) x d, where a = ammonia injection rate(lb/hr)/17(lb/lb. mol), b = dry exhaust gas flow rate (lb/hr)/(29(lb/lb. mol), c = change in measured NOx concentration ppmvd at 15% O2 across catalyst, and d =correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip. Alternatively, permittee may utilize a continuous in-stack ammonia monitor, acceptable to the District, to monitor compliance. At least 60 days prior to using a NH3 CEM, the permittee must submit a monitoring plan for District review and approval. [District Rule 4102] Federally Enforceable Through Title V Permit

44. Short term emission limits (lb/hr and ppmvd @ 15% O2) shall be measured annually by District witnessed in-situ sampling of exhaust gases by a qualified independent source test firm at full load conditions as follows - NOx: ppmvd @ 15% O2 and lb/hr, CO: ppmvd @ 15% O2 and lb/hr, VOC: ppmvd @ 15% O2 and lb/hr, PM10: lb/hr, and ammonia: ppmvd @ 15% O2. Sample collection to demonstrate compliance with ammonia emission limit shall be based on three consecutive test runs of thirty minutes each. [District Rules 1081 and 4703, and PSD SJ 01-01] Federally Enforceable Through Title V Permit

45. Startup NOx, CO, and VOC mass emission limits shall be measured for one of the CTGs (S-3746-1, or -2) at least every seven years by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. [District Rule 1081] Federally Enforceable Through Title V Permit

46. The District and the EPA must be notified 30 days prior to any source test, and a source test plan must be submitted for approval 15 days prior to testing. Official test results and field data collected by source tests required by conditions on this permit shall be submitted to the District within 60 days of testing. [District Rule 1081 and PSD SJ 01-01] Federally Enforceable Through Title V Permit

47. The following test methods shall be used PM10: EPA method 5 (front half and back halt) or 201A, NOx: EPA Method 7E or 20, CO: EPA method 1 0 or 1 OB, O2: EPA Method 3, 3A, or 20, VOC: EPA method 1 8 or 25, ammonia: BAAQMD ST-18, and fuel gas sulfur content: ASTM 03246 or ASTM 06228. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [40 CFR ~~60.335(a) & (c)~~ 60.4400, District Rules 1081, 4001, 4703, and PSD SJ 01-01] Federally Enforceable Through Title V Permit

48. Results of the CEM system shall be averaged over a three hour period, using consecutive 15-minute sampling periods in accordance with either EPA Method 7E or EPA Method 20 for NOx, EPA Test Methods 10 or I OB for CO, or EPA Methods 3, 3A, or 20 for O2, or, if continuous emission monitors are used, all applicable requirements of CFR 60.13. [40 CFR 60.13 and District Rule 4 703] Federally Enforceable Through Title V Permit.

49. The permittee shall maintain hourly records of NOx, CO, and ammonia emission concentrations (ppmvd @ 15% O2), and hourly, daily, and twelve month rolling average records of NOx and CO emissions. [District NSR Rule] Federally Enforceable Through Title V Permit

50. The permittee shall maintain records of SOx lb/hr, lb/day, and lb/twelve month rolling average emission. SOx emissions shall be based on fuel use records, natural gas sulfur content, and mass balance calculations. [District NSR Rule] Federally Enforceable Through Title V Permit

51. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary of data shall be in the form and the manner prescribed by the APCO. [District Rule 1080, 7.1] Federally Enforceable Through Title V Permit

52. The owner or operator shall maintain records that contain the following: the occurrence and duration of any start-up, shutdown or malfunction, performance testing, evaluations, calibrations, checks, adjustments, any periods during which a continuous monitoring system or monitoring device is inoperative, maintenance of any CEM system that has been installed pursuant to District Rule 1080 (as amended 12/17/92), and emission measurements. [40 CFR 60.7(b), 40 CFR 60.8(d), District Rules 1080 and 2201, 40 CFR 64 and PSD SJ 01-01] Federally Enforceable Through Title V Permit

53. APCO or an authorized representative shall be allowed to inspect, as he or she determines to be necessary, the monitoring devices required by this rule to ensure that such devices are functioning properly. [District Rule 1080, 11.0 and PSD SJ 01-01] Federally Enforceable Through Title V Permit

54. The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for

reduced load periods, total hours of operation, the type and quantity of fuel used, and duration of each start-up and each shutdown time period. [District Rule 4703] Federally Enforceable Through Title V Permit

55. All records required to be maintained by this permit shall be maintained for a period of five years and shall be made readily available for District inspection upon request. [District Rules 2201 and 4703, and PSD SJ 01-01] Federally Enforceable Through Title V Permit

56. The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75. [40 CFR Part 75] Federally Enforceable Through Title V Permit

57. The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program. [40 CFR Part 75] Federally Enforceable Through Title V Permit

58. The owners and operators of each source and each affected unit at the source shall: (i) hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR Part 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and (ii) comply with the applicable Acid Rain emissions limitations for sulfur dioxide. [40 CFR Part 73] Federally Enforceable Through Title V Permit

59. Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act. [40 CFR Part 77] Federally Enforceable Through Title V Permit

60. An affected unit shall be subject to the sulfur dioxide requirements starting on the later of January 1, 2000, or the deadline for monitoring certification under 40 CFR part 75, an affected unit under 40 CFR Part 72.6(a)(3) that is not a substitution or compensating unit. [40 CFR Part 72, 40 CFR Part 75] Federally Enforceable Through Title V Permit

61. Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program. [40 CFR Part 72] Federally Enforceable Through Title V Permit

62. An allowance shall not be deducted in order to comply with the requirements under 40 CFR Part 73, prior to the calendar year for which the allowance was allocated. [40 CFR Part 73] Federally Enforceable Through Title V Permit

63. An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR Part 72. 7 and Part 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. [40 CFR Part 72] Federally Enforceable Through Title V Permit

64. An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right. [40 CFR Part 72] Federally Enforceable Through Title V Permit

65. The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides. [40 CFR Part 72] Federally Enforceable Through Title V Permit

66. The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR Part 77. [40 CFR Part 77] Federally Enforceable Through Title V Permit

67. The owners and operators of an affected unit that has excess emissions in any calendar year shall: (i) pay without demand the penalty required, and pay up on demand the interest on that penalty; and (ii) comply with the terms of an approved offset plan, as required by 40 CFR Part 77. [40 CFR Part 77] Federally Enforceable Through Title V Permit

68. The owners and operators of the each affected unit at the source shall keep on site the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority: (i) The certificate of representation for the designated representative for the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR Part 72.24; provided that the certificate and documents shall be retained on site beyond such five-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative. [40 CFR Part 72] Federally Enforceable Through Title V Permit

69. The owners and operators of each affected unit at the source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority; (ii) All emissions monitoring information, in accordance with 40 CFR Part 75; (iii) Copies of all reports, compliance certifications and other submissions and all records made or required under the Acid Rain Program; (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission that demonstrates compliance with the requirements of the Acid Rain Program. [40 CFR Part 72, 40 CFR Part 75] Federally Enforceable Through Title V Permit

70. The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 75 Subpart I. [40 CFR Part 75] Federally Enforceable Through Title V Permit

71. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following subsumed requirements: Rule 407 (Kern) as of the date of permit issuance. A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

72. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following applicable requirements: 40 CFR Part 60, Subpart KKKK ~~60.332 (a)(l) and (b),~~

~~60.333 (a) and (b), 60.334 (c), h(l), h(3) and (j), and 60.335 (a), (b)(3), and (c)~~; District Rule 4703 (as amended 09/20/07), Sections 5.1.3, 5.2, 5.3, 6.1 , 6.3.1 , 6.3.3, 6.4.1, 6.4.2, 6.4.3, and 6.4.5 as of the date of permit issuance. A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

73. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following applicable requirements: 40 CFR 60.7(b), 60.8, 60.8(d), 60.13, and 60.13(b); District Rules 1080 (as amended 12/17/92), Sections 6.3, 6.4, 6.5, 7.0, 7.1, 7.2, 7.3, 8.0, 9.0, 10.0, and 11.0; and 1081 (as amended 12/16/93) as of the date of permit issuance. A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

Permit Unit S-3746-2-13: ~~160 MW~~ <u>190 MW</u> NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF GENERAL ELECTRIC FRAME 7FA NATURAL GAS-.FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW-NOX COMBUSTORS, HEAT RECOVERY STEAM GENERATOR WITH DUCT FIRING, SCR, AND OXIDATION CATALYSTS (~~585~~ <u>635</u> MW TOTAL PLANT NOMINAL RATING)

1. While dormant, the fuel line shall be physically disconnected from the unit. [District Rule 2080]

2. Permittee shall submit written notification to the District upon designating the unit as dormant or active. [District Rule 2080]

3. While dormant, normal source testing shall not be required. [District Rule 2080]

4. Upon recommencing operation of this unit, normal source testing shall resume. [District Rule 2080]

5. Any source testing required by this permit shall be performed within 60 days of recommencing operation of this unit, regardless of whether the unit remains active or is again designated as dormant. [District Rule 2080]

6. Records of all dates and times that this unit is designated as dormant or active, and copies of all corresponding notices to the District, shall be maintained, retained for a period of at least five years, and made available for District inspection upon request. [District Rule 1070]

7. Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators to maintain visible emissions from lube oil vents no greater than 5% opacity, except for three minutes in any hour. [District NSR Rule] Federally Enforceable Through Title V Permit

8. CTG shall be equipped with continuously recording fuel gas flowmeter. [District NSR Rule] Federally Enforceable Through Title V Permit

9. CTG exhaust after the SCR unit shall be equipped with continuously recording emissions monitors dedicated to this unit for NOx, CO, and O2. Continuous emissions monitors shall meet the requirements of 40 CFR Part 60, Appendices Band F, and 40 CFR Part 75, and shall be capable of monitoring emissions during startups and shutdowns as well as normal operating conditions. If relative accuracy of CEM(s) cannot be demonstrated during startup

conditions, CEM results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits. [40 CFR 60.334(c), District Rules 1080, 2201 and 4703, 40 CFR 64, and PSD SJ 01-01] Federally Enforceable Through Title V Permit

10. CTG shall be equipped with a continuously recording emission monitor preceding the SCR module measuring NOx concentration for the purposes of calculating ammonia slip. Permittee shall check, record, and quantify the calibration drift (CD) at two concentration values at least once daily (approximately 24 hours). The calibration shall be adjusted whenever the daily zero or high-level CD exceeds 5%. If either the zero or high-level CD exceeds 5% for five consecutive daily periods, the analyzer shall be deemed out-of-control. If either the zero or high-level CD exceeds 10% during any CD check, analyzer shall be deemed out-of-control. If the analyzer is out-of-control, the permittee shall take appropriate corrective action and then repeat the CD check. [District NSR Rule, and 40 CFR 64] Federally Enforceable Through Title V Permit

11. The facility shall maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080] Federally Enforceable Through Title V Permit

12. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080] Federally Enforceable Through Title V Permit

13. The owner or operator shall be required to conform to the compliance testing and sampling procedures described in District Rule 1081 (as amended 12/16/93). [District Rule 1081] Federally Enforceable Through Title V Permit

14. CEM cycling times shall be those specified in 40 CFR, Part 51, Appendix P, Sections 3.4, 3.4.1 and 3.4.2, or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080, and 40 CFR 64] Federally Enforceable Through Title V Permit

15. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1081] Federally Enforceable Through Title V Permit

16. Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080] Federally Enforceable Through Title V Permit

17. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080] Federally Enforceable Through Title V Permit

18. The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080] Federally Enforceable Through Title V Permit

19. Operators of CEM systems installed at the direction of the APCO shall submit a written report for each calendar quarter to the APCO and EPA (Attn: AIR-5). The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess emissions, nature and cause of excess (if known}, corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred; And reports on opacity monitors giving the number of three minute periods during which the average opacity exceeded the standard for each hour of operation. The averaged may be obtained by integration over the averaging period or by arithmetically averaging a minimum of four equally spaced instantaneous opacity measurements per minute. Any time exempted shall be considered before determining the excess averages of opacity. [40 CFR 64, District Rule 1080 and PSD SJ 01-01] Federally Enforceable Through Title V Permit

20. An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NOX emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NOX emission rate" is the arithmetic average of the average NOX emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NOX emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NOX emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NOX emission rate" is the arithmetic average of all hourly NOX emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NOX emissions rates for the preceding 30 unit operating days if a valid NOX emission rate is obtained for at least 75 percent of all operating hour. ~~An hour of excess emissions shall be defined as any operating hour in which 4-hour rolling average NOx concentration exceeds applicable emissions limit in §60.332(a)(l}, and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NOx, CO or O2. The 4-hour rolling average is the arithmetic average of the average NOx concentration measured by the CEMS for a given hour (corrected to 15 percent O2) and the three unit operating hour average NOx~~

~~concentrations immediately preceding that unit operating hour.~~ [40 CFR 64 and 40 CFR ~~60.334(j)(l)(iii)~~60.4380(b)(1)] Federally Enforceable Through Title V Permit

21. The owner or operator shall submit reports of NOx excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c) on a semiannual basis. Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction~~, for any 4-consecutive rolling average that exceeds the NOx limit under 40 CFR 60.332(a)(l).~~ For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined in 40 CFR ~~60.3340~~ 60.4380. All reports· required under 40 CFR 60.7(c) shall be postmarked by the 30th day following the end of each six-month period. [40 CFR ~~60.3340~~ 60.4395, ~~40 CFR 60.334 (j)(5)~~and District Rule 4703] Federally Enforceable Through Title V Permit

22. If the total duration of NOx excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CEMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form in §60.7(d) shall be submitted and the excess emission report described in §60.7(c) need not be submitted unless requested by the EPA or the Air District. [40 CFR ~~60.334~~ 60.4345), and 40 CFR 60.7(c) and (d)] Federally Enforceable Through Title V Permit

23. Ammonia injection grid shall be equipped with operational ammonia flowmeter and injection pressure indicator. [District NSR Rule] Federally Enforceable Through Title V Permit

24. Permittee shall monitor and record exhaust gas temperature at selective catalytic reduction and oxidation catalyst inlets. [District NSR Rule] Federally Enforceable Through Title V Permit

25. Particulate matter emissions shall not exceed 0. 1 grains/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit

26. CTG shall be fired exclusively on natural gas, consisting primarily of methane and ethane, with a sulfur content no greater than 0.25 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [40 CFR ~~60.333(b)~~ 60.4330(a)(2), District NSR Rule, PSD SJ 01-01] Federally Enforceable Through Title V Permit

27. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored weekly using ASTM Methods 04084, 05504, 06228, or Gas Processors Association Standard 2377. If sulfur content is less than 0.25 gr/100 scf for 8 consecutive weeks, then the Monitoring frequency shall be every six (6) months. If any six (6) month monitoring show an exceedance, weekly monitoring shall resume. [40 ~~CFR 60.334(h)(1) & (3)~~ 60.4360 and District Rule 2520, 9.3.2] Federally Enforceable Through Title V Permit

28. Sulfur compound emissions shall not exceed 0.015% by volume at 15% oxygen, on a dry basis averaged over 15 consecutive minutes. [~~40 CFR 60.333(a);~~; County Rule 407 (Kern)] Federally Enforceable Through Title V Permit

29. Startup is defined as the period beginning with turbine initial firing. Shutdown is defined by the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Startup and shutdown durations shall not exceed 60 minutes for a hot startup, 128 minutes for a warm startup, and 230 minutes for a cold startup, and one hour for a shutdown, per occurrence. [District Rules 2201, 4001 & 4703, and PSD SJ 01-01] Federally Enforceable Through Title V Permit

30. ~~Reduced load period is defined as the time during which a gas turbine is operated at less than rated capacity in order to change the position of the exhaust gas diverter gate. Each reduced load period shall not exceed one hour. [District Rule 4703] Federally Enforceable Through Title V Permit~~

31. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703] Federally Enforceable Through Title V Permit

32. The owner or operator shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when the CEMS is not operating properly. [District Rule 4703] Federally Enforceable Through Title V Permit

33. The HHV and LHV of the fuel combusted shall be determined using ASTM 03588, ASTM 1826, or ASTM 1945. [~~40 CFR 60.332(a) and (b) and~~ District Rule 4703] Federally Enforceable Through Title V Permit

34. An owner or operator of any gas turbine with an intermittently operated auxiliary burner shall demonstrate compliance with the auxiliary burner both on and off. [~~40 CFR 60.335(b)(3) and~~ <u>40 CFR 60.4400 and</u> District Rule 4703] Federally Enforceable Through Title V Permit

35. Ammonia shall be injected when the selective catalytic reduction system catalyst temperature exceeds 500 degrees F. Permittee shall monitor and record catalyst temperature during periods of startup. [District NSR Rule] Federally Enforceable Through Title V Permit

36. During startup or shutdown of any gas turbine engine(s), combined emissions from both gas turbine engines (S-3746-1 and -2) heat recovery steam generator exhausts shall not exceed any of the following: NOx (as NO2)- 700 lb and CO -1,580 lb, in any one hour. If any CTG is in either startup or shutdown mode during any portion of a clock hour, the facility will be subject to the aforementioned limits during that clock hour. [District NSR Rule] Federally Enforceable Through Title V Permit

37. Emission rates from each CTG, except during startup and/or shutdown, shall not exceed any of the following: PM10 -17.8 lb/hr, SOx (as SO2) – ~~1.55~~ <u>1.58</u> lb/hr, NOx (as NO2)- ~~15.96~~ <u>16.74</u> lb/hr and 2.0 ppmvd@ 15% O2, VOC - ~~5.51~~ <u>5.84</u> lb/hr and 2.0 ppmvd@ 15% O2, CO - ~~19.22~~ <u>20.38</u> lb/hr and 4 ppmvd@ 15% O2, ammonia - 10 ppmvd@ 15%O2. NOx (as NO2) ppmvd and lb/hr limits are a one-hour rolling average. Ammonia emission limit is a twenty-four hour rolling average. All other ppmvd and lb/hr limits are three-hour rolling averages. If a CTG is in either startup or shutdown mode during any portion of a clock hour, that unit will not be subject to the aforementioned limits during that clock hour. [40 CFR ~~60.332(a)(1)~~

60.4320(a), District Rules 2201, 4001, 4703, and PSD SJ 01-01] Federally Enforceable Through Title V Permit

38. Emission rates from each CTG shall not exceed any of the following: PM10 - 461.2 lb/day, SOx (as SO2) - ~~37.2~~ 38.1 lb/day, NOx (as NO2) – 1,170.9 lb/day, VOC - 220.6 lb/day, and CO - 2,443.4 lb/day. [District NSR Rule] Federally Enforceable Through Title V Permit

39. Emission rates from both CTGs (S-3746-1 and -2) shall not exceed any of the following: PM10 - 922.3 lb/day, SOx (as SO2) - ~~74.4~~ 76.3 lb/day, NOx (as NO2) - 2,341.8 lb/day, VOC – 441.2 lb/day, and CO - 4,886.8 lb/day. [District NSR Rule and PSD SJ 01-01] Federally Enforceable Through Title V Permit

40. Annual emissions from both CTGs calculated on a twelve consecutive month rolling basis shall not exceed any of the following: PM10 - 269,651 lb/year, SOx (as SO2)- 24,259 lb/year, NOx (as NO2)- 311,337 lb/year, VOC - 87,674 lb/year, and CO - 507,978 lb/year. [District NSR Rule and PSD SJ 01-01] Federally Enforceable Through Title V Permit

41. Each one-hour period in a one-hour rolling average will commence on the hour. Each one-hour period in a three-hour rolling average will commence on the hour. The three-hour average will be compiled from the three most recent one hour periods. Each one-hour period in a twenty-four-hour average for ammonia slip will commence on the hour. The twenty-four-hour average will be calculated starting and ending at twelve-midnight. [District NSR Rule and PSD SJ 01 - 01] Federally Enforceable Through Title V Permit

42. Daily emissions will be compiled for a twenty-four period starting and ending at twelve-midnight. Each calendar month in a twelve-consecutive-month rolling emissions will commence at the beginning of the first day of the month. The twelve-consecutive-month rolling emissions total to determine compliance with annual emissions will be compiled from the twelve most recent calendar months. [District NSR Rule and PSD SJ 01-01] Federally Enforceable Through Title V Permit

43. Ammonia slip limit shall be measured using the following calculation procedure: ammonia slip ppmvd @ 15% O2 = ((a-(bxc/1,000,000)) x 1,000,000 / b) x d, where a = ammonia injection rate(lb/hr)/17(lb/lb. mol), b = dry exhaust gas flow rate (lb/hr)/(29(lb/lb. mol), c = change in measured NOx concentration ppmvd at 15% O2 across catalyst, and d =correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip. Alternatively, permittee may utilize a continuous in-stack ammonia monitor, acceptable to the District, to monitor compliance. At least 60 days prior to using a NH3 CEM, the permittee must submit a monitoring plan for District review and approval. [District Rule 4102] Federally Enforceable Through Title V Permit

44. Short term emission limits (lb/hr and ppmvd @ 15% O2) shall be measured annually by District witnessed in-situ sampling of exhaust gases by a qualified independent source test firm at full load conditions as follows - NOx: ppmvd @ 15% O2 and lb/hr, CO: ppmvd @ 15% O2 and lb/hr, VOC: ppmvd @ 15% O2 and lb/hr, PM 10: lb/hr, and ammonia: ppmvd @ 15% O2. Sample collection to demonstrate compliance with ammonia emission limit shall be based on three consecutive test runs of thirty minutes each. [District Rules 1081 and 4703, and PSD SJ 01-01] Federally Enforceable Through Title V Permit

45. Startup NOx, CO, and VOC mass emission limits shall be measured for one of the CTGs (S-3746-1, or -2) at least every seven years by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. [District Rule 1081] Federally Enforceable Through Title V Permit

46. The District and the EPA must be notified 30 days prior to any source test, and a source test plan must be submitted for approval 15 days prior to testing. Official test results and field data collected by source tests required by conditions on this permit shall be submitted to the District within 60 days of testing. [District Rule 1081 and PSD SJ 01-01] Federally Enforceable Through Title V Permit

47. The following test methods shall be used PM10: EPA method 5 (front half and back halt) or 201A, NOx: EPA Method 7E or 20, CO: EPA method 1 0 or 1 OB, O2: EPA Method 3, 3A, or 20, VOC: EPA method 1 8 or 25, ammonia: BAAQMD ST-18, and fuel gas sulfur content: ASTM 03246 or ASTM 06228. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [40 CFR ~~60.335(a) & (c)~~ 60.4400, District Rules 1081, 4001, 4703, and PSD SJ 01-01] Federally Enforceable Through Title V Permit

48. Results of the CEM system shall be averaged over a three hour period, using consecutive 15-minute sampling periods in accordance with either EPA Method 7E or EPA Method 20 for NOx, EPA Test Methods 10 or 10B for CO, or EPA Methods 3, 3A, or 20 for O2, or, if continuous emission monitors are used, all applicable requirements of CFR 60.13. [40 CFR 60.13 and District Rule 4 703] Federally Enforceable Through Title V Permit.

49. The permittee shall maintain hourly records of NOx, CO, and ammonia emission concentrations (ppmvd @ 15% O2), and hourly, daily, and twelve month rolling average records of NOx and CO emissions. [District NSR Rule] Federally Enforceable Through Title V Permit

50. The permittee shall maintain records of SOx lb/hr, lb/day, and lb/twelve month rolling average emission. SOx emissions shall be based on fuel use records, natural gas sulfur content, and mass balance calculations. [District NSR Rule] Federally Enforceable Through Title V Permit

51. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary of data shall be in the form and the manner prescribed by the APCO. [District Rule 1080, 7.1] Federally Enforceable Through Title V Permit

52. The owner or operator shall maintain records that contain the following: the occurrence and duration of any start-up, shutdown or malfunction, performance testing, evaluations, calibrations, checks, adjustments, any periods during which a continuous monitoring system or monitoring device is inoperative, maintenance of any CEM system that has been installed pursuant to District Rule 1080 (as amended 12/17/92), and emission measurements. [40 CFR 60.7(b), 40 CFR 60.8(d), District Rules 1080 and 2201, 40 CFR 64 and PSD SJ 01-01] Federally Enforceable Through Title V Permit

53. APCO or an authorized representative shall be allowed to inspect, as he or she determines to be necessary, the monitoring devices required by this rule to ensure that such devices are functioning properly. [District Rule 1080, 11.0 and PSD SJ 01-01] Federally Enforceable Through Title V Permit

54. The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, the type and quantity of fuel used, and duration of each start-up and each shutdown time period. [District Rule 4703] Federally Enforceable Through Title V Permit

55. All records required to be maintained by this permit shall be maintained for a period of five years and shall be made readily available for District inspection upon request. [District Rules 2201 and 4703, and PSD SJ 01-01] Federally Enforceable Through Title V Permit

56. The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75. [40 CFR Part 75] Federally Enforceable Through Title V Permit

57. The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program. [40 CFR Part 75] Federally Enforceable Through Title V Permit

58. The owners and operators of each source and each affected unit at the source shall: (i) hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR Part 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and (ii) comply with the applicable Acid Rain emissions limitations for sulfur dioxide. [40 CFR Part 73] Federally Enforceable Through Title V Permit

59. Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act. [40 CFR Part 77] Federally Enforceable Through Title V Permit

60. An affected unit shall be subject to the sulfur dioxide requirements starting on the later of January 1, 2000, or the deadline for monitoring certification under 40 CFR part 75, an affected unit under 40 CFR Part 72.6(a)(3) that is not a substitution or compensating unit. [40 CFR Part 72, 40 CFR Part 75] Federally Enforceable Through Title V Permit

61. Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program. [40 CFR Part 72] Federally Enforceable Through Title V Permit

62. An allowance shall not be deducted in order to comply with the requirements under 40 CFR Part 73, prior to the calendar year for which the allowance was allocated. [40 CFR Part 73] Federally Enforceable Through Title V Permit

63. An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR Part 72. 7 and Part 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. [40 CFR Part 72] Federally Enforceable Through Title V Permit

64. An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right. [40 CFR Part 72] Federally Enforceable Through Title V Permit

65. The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides. [40 CFR Part 72] Federally Enforceable Through Title V Permit

66. The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR Part 77. [40 CFR Part 77] Federally Enforceable Through Title V Permit

67. The owners and operators of an affected unit that has excess emissions in any calendar year shall: (i) pay without demand the penalty required, and pay up on demand the interest on that penalty; and (ii) comply with the terms of an approved offset plan, as required by 40 CFR Part 77. [40 CFR Part 77] Federally Enforceable Through Title V Permit

68. The owners and operators of the each affected unit at the source shall keep on site the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority: (i) The certificate of representation for the designated representative for the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR Part 72.24; provided that the certificate and documents shall be retained on site beyond such five-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative. [40 CFR Part 72] Federally Enforceable Through Title V Permit

69. The owners and operators of each affected unit at the source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority; (ii) All emissions monitoring information, in accordance with 40 CFR Part 75; (iii) Copies of all reports, compliance certifications and other submissions and all records made or required under the Acid Rain Program; (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission that demonstrates compliance with the requirements of the Acid Rain Program. [40 CFR Part 72, 40 CFR Part 75] Federally Enforceable Through Title V Permit

70. The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 75 Subpart I. [40 CFR Part 75] Federally Enforceable Through Title V Permit

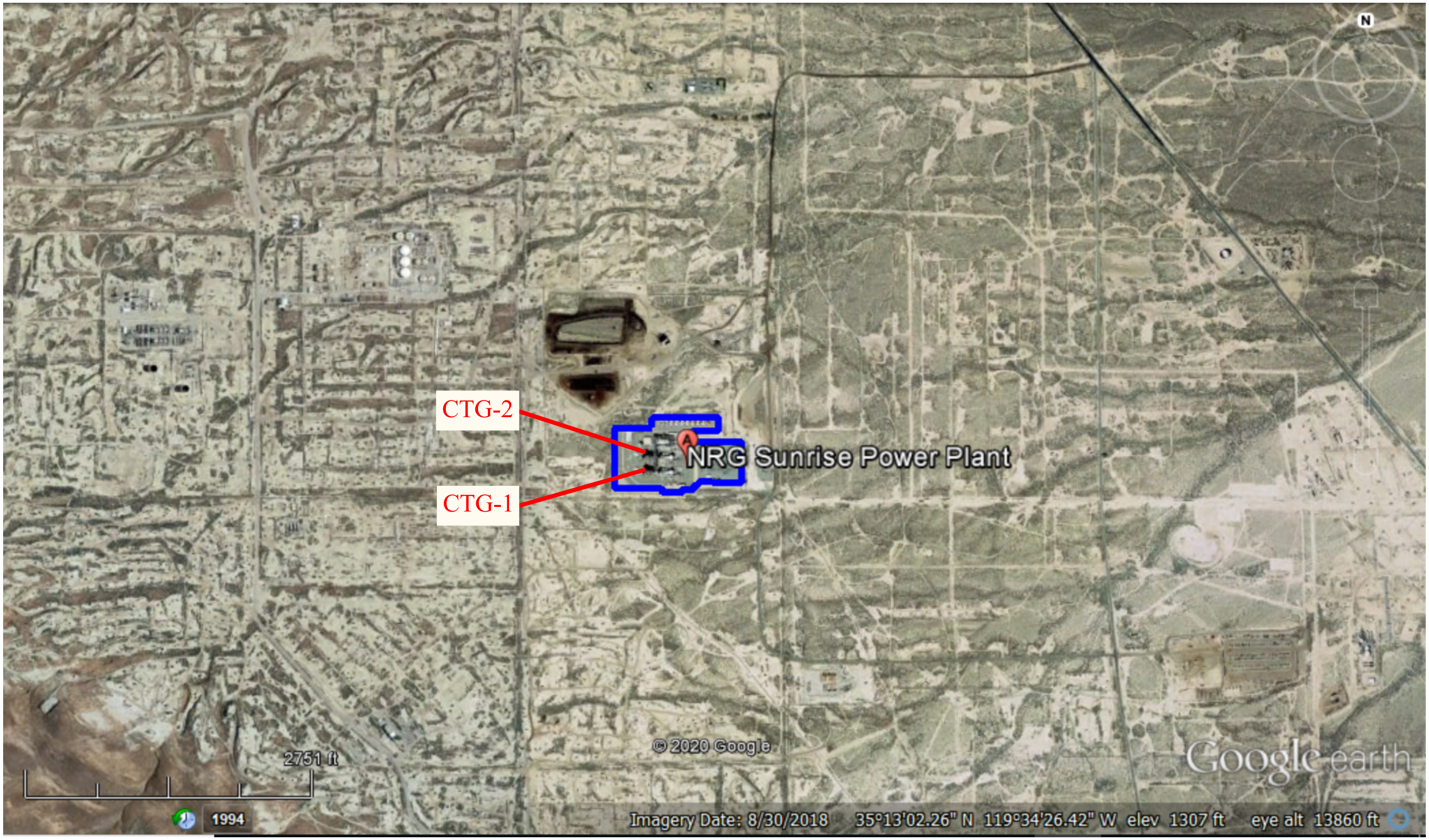
71. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following subsumed requirements: Rule 407 (Kern) as of the date of permit issuance. A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

72. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following applicable requirements: 40 CFR Part 60, Subpart KKKK ~~60.332 (a)(l) and (b), 60.333 (a) and (b), 60.334 (c), h(l), h(3) and (j), and 60.335 (a), (b)(3), and (c)~~; District Rule 4703 (as amended 09/20/07), Sections 5.1.3, 5.2, 5.3, 6.1 , 6.3.1 , 6.3.3, 6.4.1, 6.4.2, 6.4.3, and 6.4.5 as of the date of permit issuance. A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

73. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following applicable requirements: 40 CFR 60.7(b), 60.8, 60.8(d), 60.13, and 60.13(b); District Rules 1080 (as amended 12/17/92), Sections 6.3, 6.4, 6.5, 7.0, 7.1, 7.2, 7.3, 8.0, 9.0, 10.0, and 11.0; and 1081 (as amended 12/16/93) as of the date of permit issuance. A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

APPENDIX B

Site Vicinity Map



Site Boundary

ERM

Appendix B
Site Vicinity Map
Sunrise Power Company
12857 Sunrise Power Road
Fellows, California

APPENDIX C

CTG Emission Calculations

Startup & Shutdown Emissions - per Turbine

Pollutant	PM10 (lb/event)	SOx (lb/event)	NOx (lb/event)	VOC (lb/event)	CO (lb/event)
Cold Startup (230 minutes/event)					
Emission Rate (lb/hr)	22	1.67	82.00	4.26	329.0
Total lb/event	84.3	6.40	314.3	16.33	1261.2
Warm Startup (128 minutes/event)					
Emission Rate (lb/hr)	40	1.67	36.11	4.26	16.30
Total lb/event	85.3	3.60	77.0	9.09	34.8
Hot Startup (60 minutes/event)					
Emission Rate (lb/hr)	22	1.67	28.00	4.26	36.00
Total lb/event	22	1.67	28	4.26	36.00
Shutdown (60 minutes)					
Emission Rate (lb/hr)	13.4	1.55	115.00	30.00	325.00
Total lb/event	13.4	1.55	115.00	30.00	325.00

Scenario #1

Current Starts	100
Proposed Starts	182
Ratio	1.82

Proposed Operating Scenario

		Qtr 1	Qtr 2	Qtr 3	Qtr 4	Annual
Number of Startup Events - Proposed	Hot (60 min. each) - Rounded	16	16	6	16	54
	Warm (128 min. each)	27	28	9	27	91
	Cold (230 min. each) - Rounded	13	11	0	13	37
Number of Startup Hours - Proposed	Hot	16	16	6	16	54
	Warm	57.6	59.7	19.2	57.6	194
	Cold	49.8	42.2	0.0	49.8	142
	Total Startup Hours	**123.4**	**117.9**	**25.2**	**123.4**	390
# of Shutdown Events	60 minutes each - Proposed (Rounded)	56	55	15	56	182
	Total Shutdown Hours	**56**	**55**	**15**	**56**	182
Hours of Operation - Proposed	Duct Burners Off	554	568	193	276	1591
	Duct Burners On	1145	1175	1931	1471	5722
Downtime Hours		282	268	43	282	875
Maximum Hours/Qtr (includes startups and shutdowns)		2160	2184	2208	2208	8760
Maximum Operating Hours - Proposed		1699	1743	2125	1747	7313

2001 Application Operating Scenario NOx, VOC and CO

		Qtr 1	Qtr 2	Qtr 3	Qtr 4	Annual
Number of Startup Events - Current	Hot (60 min. each)	9	9	3	9	30
	Warm (128 min. each)	15	15	5	15	50
	Cold (230 min. each)	7	6	0	7	20
Number of Startup Hours - Current	Hot	9	9	3	9	30
	Warm	32	32	11	32	107
	Cold	27	23	0	27	77
	Total Startup Hours	**68**	**64**	**14**	**68**	213
# of Shutdown Events	60 minutes each - Current	31	30	8	31	100
	Total Shutdown Hours	31	30	8	31	100
Hours of Operation - Current	Duct Burners Off	575	812	195	286	1868
	Duct Burners On	1189	1005	1948	1526	5669
Downtime Hours		297	273	43	297	910
Maximum Hours/Qtr (includes startups and shutdowns)		2160	2184	2208	2208	8760
Maximum Operating Hours - Current		1764	1817	2143	1812	7537

Sunrise Power Company Emission Calculations

Assumptions and Emissions Calculation Methodology:

For the proposed project with 182 startups per year, a ratio of 1.82 (Proposed Starts/Current Starts = 182 starts/100 starts = 1.82) was applied to the current first case startup and shutdown operating scenario.
Start-up and shut down hours per quarter are as follows: Q1 = 180; Q2 = 171; Q3 = 39; Q4 = 180
The number of starts and shut downs were taken from the 2001 permit application and ratioed to get the breakdown of cold, warm and hot starts for the 182 starts per year.
Startup emissions for VOC, NOx and CO in lb/event were calculated using startup source test data and minutes per event specified in the 2001 application.
Startup emissions for SOx and PM10 in terms of lb/event were taken from the 2001 permit application. These emissions are typically fuel dependent.
Hot start PM10 in lb/hr assumed to be the same as cold start lb/hr. Shut down PM10 was set as equal to CTG PM10 without duct firing.
Quarterly and annual emissions are based on the hypothetical operating schedules as shown in the Scenario # 1 table.
The proposed project emission rates are based on projected emission rates for VOC. CTG data used for unfired and 2.0 ppmv used for fired duct burner.
The current permit emission concentration limits will remain unchanged as they represent best available control technology (BACT) and we are not proposing any limits on the types of operation.

Maximum Turbine Daily Emissions

Pollutant	Startup Emissions (lb/event)	Shutdown Emissions (lb/event)	Max Emissions lb/hr @ 100% Load	Emissions @ baseload operation	Daily Emissions (per CTG)	Combined Daily Emissions for CTGs
PM10	85.3	13.4	17.80	341.17	439.87	879.75
SOx	6.4	1.55	1.58	30.19	38.14	76.28
NOx	314.30	115	16.74	320.76	750.06	1500.12
VOC	16.33	30	5.84	111.84	158.17	316.34
CO	1261.20	325	20.38	390.62	1976.82	3953.65

1st and 4th Quarter: Hourly Emission Rates @ 100% Load, 30°F

	PM10	SOx	NOx	VOC	CO
Mass Emission Rates w/Duct Burner Firing (per turbine, lb/hr)	17.80	1.58	16.74	5.84	20.38
Mass Emission Rates without Duct Burner Firing (per turbine, lb/hr)	13.40	1.36	14.36	2.85	17.49

2nd Quarter: Hourly Emission Rates @ 100% Load, 65°F

	PM10	SOx	NOx	VOC	CO
Mass Emission Rates w/Duct Burner Firing (per turbine, lb/hr)	17.51	1.52	16.15	5.63	19.66
Mass Emission Rates without Duct Burner Firing (per turbine, lb/hr)	12.16	1.27	13.41	2.71	16.33

3rd Quarter: Hourly Emission Rates @ 100% Load, 115°F

	PM10	SOx	NOx	VOC	CO
Mass Emission Rates w/Duct Burner Firing (per turbine, lb/hr)	16.95	1.45	15.44	5.38	18.80
Mass Emission Rates without Duct Burner Firing (per turbine, lb/hr)	11.68	1.18	12.52	2.56	15.24

First Quarter Operating Hours: 30°F, 100% Load

Hours of Duct Burner Firing	1145
Hours of Non-Duct Burner Firing	554

First Quarter Startup/Shutdown Emissions

	PM10 (lbs/qtr)	SOx (lbs/qtr)	NOx (lbs/qtr)	VOC (lbs/qtr)	CO (lbs/qtr)
Startup Emissions	3,751	207	6,613	526	17,911
# of Hot starts	16	16	16	16	16
Hot Start Emissions	352	27	448	68	576
# of Warm Starts	27	27	27	27	27
Warm Start Emissions	2,303	97	2,079	245	940
# Cold Starts	13	13	13	13	13
Cold Start Emissions	1,096	83	4,086	212	16,396
Shutdown Emissions	750	87	6,440	1,680	18,200
# of Shutdowns	56	56	56	56	56
Total Startup & Shutdown Emissions	**4,501**	**294**	**13,053**	**2,206**	**36,111**

First Quarter Total Emissions: 30°F, 100% Load

	PM10 (lbs/qtr)	SOx (lbs/qtr)	NOx (lbs/qtr)	VOC (lbs/qtr)	CO (lbs/qtr)
Startup/Shutdown Emissions	4,501	294	13,053	2,206	36,111
Baseload Emissions w/duct firing	20,379	1,803	19,160	6,686	23,333
Baseload Emissions w/o duct firing	7,419	750	7,951	1,577	9,684
Total Quarterly PE (per CTG)	32,300	2,847	40,163	10,469	69,128
Total Combined Quarterly PE (2 CTGs)	**64,599**	**5,695**	**80,327**	**20,938**	**138,256**

Permit Application 2001

Hours w duct firing	1,189.00
Hours w/o duct firing	575.00
Total hours	1,764.00
Fraction with Duct Firing	0.67
Fraction without Duct Firing	0.33

Second Quarter Operating Hours: 65°F, 100% Load

Hours of Duct Burner Firing	1175
Hours of Non-Duct Burner Firing	568

Second Quarter Startup/Shutdown Emissions

	PM10 (lbs/qtr)	SOx (lbs/qtr)	NOx (lbs/qtr)	VOC (lbs/qtr)	CO (lbs/qtr)
Startup Emissions	3,668	198	6,061	502	15,424
# of Hot starts	16	16	16	16	16
Hot Start Emissions	352	27	448	68	576
# of Warm Starts	28	28	28	28	28
Warm Start Emissions	2,388	101	2,156	254	974
# Cold Starts	11	11	11	11	11
Cold Start Emissions	927	70	3,457	180	13,873
Shutdown Emissions	737	85	6,325	1,650	17,875
# of Shutdowns	55	55	55	55	55
Total Startup & Shutdown Emissions	**4,405**	**283**	**12,386**	**2,152**	**33,299**

Second Quarter Total Emissions: 65°F, 100% Load

	PM10 (lbs/qtr)	SOx (lbs/qtr)	NOx (lbs/qtr)	VOC (lbs/qtr)	CO (lbs/qtr)
Startup/Shutdown Emissions	4,405	283	12,386	2,152	33,299
Baseload Emissions w/duct firing	20,573	1,786	18,975	6,615	23,099
Baseload Emissions w/o duct firing	6,907	719	7,619	1,542	9,278
Total Quarterly PE (per CTG)	31,884	2,788	38,981	10,309	65,676
Total Combined Quarterly PE (2 CTGs)	**63,769**	**5,576**	**77,961**	**20,618**	**131,352**

Permit Application 2001

Hours w duct firing	1,005.00
Hours w/o duct firing	812.00
Total Baseload Emissions	1817
Fraction with Duct Firing	0.55
Fraction without Duct Firing	0.45

Third Quarter Operating Hours: 115°F, 100% Load

Hours of Duct Burner Firing	1931
Hours of Non-Duct Burner Firing	193

Third Quarter Startup/Shutdown Emissions

	PM10 (lbs/qtr)	SOx (lbs/qtr)	NOx (lbs/qtr)	VOC (lbs/qtr)	CO (lbs/qtr)
Startup Emissions	900	42	861	107	529
# of Hot starts	6	6	6	6	6
Hot Start Emissions	132	10	168	26	216
# of Warm Starts	9	9	9	9	9
Warm Start Emissions	768	32	693	82	313
# Cold Starts	0	0	0	0	0
Cold Start Emissions	0	0	0	0	0
Shutdown Emissions	201	23	1,725	450	4,875
# of Shutdowns	15	15	15	15	15
Total Startup & Shutdown Emissions	**1,101**	**66**	**2,586**	**557**	**5,404**

Third Quarter Total Emissions: 115°F, 100% Load

	PM10 (lbs/qtr)	SOx (lbs/qtr)	NOx (lbs/qtr)	VOC (lbs/qtr)	CO (lbs/qtr)
Startup/Shutdown Emissions	1,179	66	2,586	557	5,404
Baseload Emissions w/duct firing	32,738	2,805	29,822	10,391	36,311
Baseload Emissions w/o duct firing	2,258	228	2,420	495	2,947
Total Quarterly PE (per CTG)	36,175	3,099	34,827	11,443	46,892
Total Combined Quarterly PE (2 CTGs)	**72,350**	**6,199**	**69,655**	**22,887**	**93,784**

Permit Application 2001

Hours w duct firing	1948
Hours w/o duct firing	195
Total Baseload Emissions	2143
Fraction with Duct Firing	0.91
Fraction without Duct Firing	0.09

Fourth Quarter Operating Hours: 30°F, 100% Load

Hours of Duct Burner Firing	1471
Hours of Non-Duct Burner Firing	276

Fourth Quarter Startup/Shutdown Emissions

	PM10 (lbs/qtr)	SOx (lbs/qtr)	NOx (lbs/qtr)	VOC (lbs/qtr)	CO (lbs/qtr)
Startup Emissions	3,729	205	6,613	526	17,911
# of Hot starts	16	16	16	16	16
Hot Start Emissions	352	27	448	68	576
# of Warm Starts	27	27	27	27	27
Warm Start Emissions	2,303	97	2,079	245	940
# Cold Starts	13	13	13	13	13
Cold Start Emissions	1,074	82	4,086	212	16,396
Shutdown Emissions	750	87	6,440	1,680	18,200
# of Shutdowns	56	56	56	56	56
Total Startup & Shutdown Emissions	**4,479**	**292**	**13,053**	**2,206**	**36,111**

Fourth Quarter Total Emissions: 30°F, 100% Load

	PM10 (lbs/qtr)	SOx (lbs/qtr)	NOx (lbs/qtr)	VOC (lbs/qtr)	CO (lbs/qtr)
Startup/Shutdown Emissions	4,479	292	13,053	2,206	36,111
Baseload Emissions w/duct firing	26,182	2,317	24,615	8,590	29,977
Baseload Emissions w/o duct firing	3,694	374	3,959	785	4,822
Total Quarterly PE (per CTG)	34,355	2,982	41,627	11,581	70,910
Total Combined Quarterly PE (2 CTGs)	**68,711**	**5,965**	**83,254**	**23,162**	**141,819**

Permit Application 2001

Hours w duct firing	1526
Hours w/o duct firing	286
Total Baseload Emissions	1812
Fraction with Duct Firing	0.84
Fraction without Duct Firing	0.16

Annual Emissions Summary - Gas Turbines

	Proposed					2001 Permit Application				
Quarter	**PM10**	**SOx**	**NOx**	**VOC**	**CO**	**PM10**	**SOx**	**NOx**	**VOC**	**CO**
1st (lbs)	64,599	5,695	80,327	20,938	138,256	63,153.20	5,890.38	81,013.38	21,529.28	139,217.16
2nd (lbs)	63,769	5,576	77,961	20,618	131,352	61,727.80	5,625.36	76,848.52	19,849.88	131,983.16
3rd (lbs)	72,350	6,199	69,655	22,887	93,784	74,590.80	6,371.52	69,374.82	22,713.76	93,784.40
4th (lbs)	68,711	5,965	83,254	23,162	141,819	70,178.80	6,371.56	84,100.36	23,571.04	142,992.80
Annual PE (lbs)	269,429	23,434	311,197	87,606	505,211	269,650.60	24,258.82	311,337.08	87,673.96	507,977.52
Annual PE (tons)	134.71	11.72	155.60	43.80	252.61	134.83	12.13	155.67	43.84	253.99
Change in PE (lbs)	-221.81	-824.72	-140.42	-68.42	-2,766.53					
Change in PE (tons)	-0.11	-0.41	-0.07	-0.03	-1.38					

Total Operating Hours per Unit

Hours of Duct Burner Firing	5722
Hours of Non-Duct Burner Firing	1591
Total Hours	**7313**

Start-up Hours		390
Shut Down Hours		182
Off line hours	(2001 Application)	875
Total		**1447**

Increase in Permitted Emissions

Permit Unit	PM10 (lb/day)	SOx (lb/day)	NOx (lb/day)	VOC (lb/day)	CO (lb/day)
Pre-Project PE					
S-3746-1-12	461.17	37.2	1170.91	220.61	2443.39
S-3746-2-12	461.17	37.2	1170.91	220.61	2443.39
S-3746-3-6	15.78	0	0	0	0
S-3746-4-5	4.2	0.1	78.3	5.6	73.5
Post-Project PE					
S-3746-1-13	439.87	38.14	750.06	158.17	1976.82
S-3746-2-13	439.87	38.14	750.06	158.17	1976.82
S-3746-3-6	15.78	0	0	0	0
S-3746-4-5	4.2	0.1	78.3	5.6	73.5
Increase in Permitted Emissions					
S-3746-1-13	-21.30	0.94	-420.85	-62.44	-466.57
S-3746-2-13	-21.30	0.94	-420.85	-62.44	-466.57
S-3746-3-6	0	0	0	0	0
S-3746-4-5	0	0	0	0	0
BACT Threshold (per unit)	2 lb/day	2 lb/day	2 lb/day	2 lb/day	2 lb/day
BACT Required (per unit)	No	Yes (CTGs only)	Yes (CTGs only)	Yes (CTGs only)	Yes (CTGs only)

Stationary Source Potential to Emit (SSPE)

Permit Unit	PM10 (lb/year)	SOx (lb/year)	NOx (lb/year)	VOC (lb/year)	CO (lb/year)
Pre-Project PE					
S-3746-1-12	134,825.30	12,129.41	155,668.54	43,836.98	253,988.76
S-3746-2-12	134,825.30	12,129.41	155,668.54	43,836.98	253,988.76
S-3746-3-6	5,759.70	0.00	0.00	0.00	0.00
S-3746-4-5	35.00	1.00	652.00	47.00	612.00
Total Pre-Project PE	**275,445**	**24,260**	**311,989**	**87,721**	**508,590**
Emission Offset Threshold Levels	29,200	54,750	20,000	20,000	200,000
Post-Project PE					
S-3746-1-13	134,714.39	11,717.05	155,598.33	43,802.77	252,605.50
S-3746-2-13	134,714.39	11,717.05	155,598.33	43,802.77	252,605.50
S-3746-3-6	5,759.70	0.00	0.00	0.00	0.00
S-3746-4-5	35.00	1.00	652.00	47.00	612.00
Total Post-Project PE	**275,223**	**23,435**	**311,849**	**87,653**	**505,823**
Change in Permitted Emissions					
S-3746-1-13	-110.91	-412.36	-70.21	-34.21	-1,383.26
S-3746-2-13	-110.91	-412.36	-70.21	-34.21	-1,383.26
S-3746-3-6	0.00	0.00	0.00	0.00	0.00
S-3746-4-5	0.00	0.00	0.00	0.00	0.00
Total Change in Permitted Emissions	**-222**	**-825**	**-140**	**-68**	**-2,767**

Major Stationary Source Calculation

Permit Unit	PM10 (lb/year)	SOx (lb/year)	NOx (lb/year)	VOC (lb/year)	CO (lb/year)
Pre-Project PE					
S-3746-1-12	134,825	12,129	155,669	43,837	253,989
S-3746-2-12	134,825	12,129	155,669	43,837	253,989
S-3746-3-6	5,760	0	0	0	0
S-3746-4-5	35	1	652	47	612
Total Pre-Project PE	**275,445**	**24,260**	**311,989**	**87,721**	**508,590**
Major Source Threshold (lbs/yr)	**140,000**	**140,000**	**20,000**	**20,000**	**200,000**
Emission Offset Threshold Levels	29,200	54,750	20,000	20,000	200,000
Pre-Project: Major Source?	**Yes**	**No**	**Yes**	**Yes**	**Yes**
Post-Project PE					
S-3746-1-13	134,714	11,717	155,598	43,803	252,605
S-3746-2-13	134,714	11,717	155,598	43,803	252,605
S-3746-3-6	5,760	0	0	0	0
S-3746-4-5	35	1	652	47	612
Total Post-Project PE	**275,223**	**23,435**	**311,849**	**87,653**	**505,823**
Major Source Threshold (lbs/yr)	**140,000**	**140,000**	**20,000**	**20,000**	**200,000**
Post-Project: Major Source?	**Yes**	**No**	**Yes**	**Yes**	**Yes**

APPENDIX B NOTICE OF INCOMPLETE APPLICATION, SJVAPCD NOVEMBER 17, 2020

November 17, 2020

David King
Sunrise Power Co, LLC
12857 Sunrise Power Rd
Fellows, CA 93224

Re: Notice of Incomplete Application
Facility Number: S-3746
Project Number: S-1204133

Dear Mr. King:

The District has received your Authority to Construct application for increasing the rating of two gas turbine engine generators and optimize the control logic of the gas turbines, at 12857 Sunrise Power Rd, Fellows. Based on our preliminary review, the application has been determined to be incomplete. The following information is required prior to further processing:

> Please provide Actual Emissions (AE) for each turbine over the last 10 years on a monthly basis in an Excell spreadsheet file. In addition, please provide Projected Actual Emissions (PAE) for each turbine as defined in the attached District APR 1150 policy titled “Implementation of Rule 2201 for SB288 Major Modification and Federal Major Modifications”.

In addition, the District has determined that the application filing fee has not been fully paid. Payment of the attached invoice is required prior to further processing.

In response, please refer to the above project number, and send to the attention of Mr. Robert C Rinaldi.

Please submit the requested information within 30 days. The District will not be able to process your application until this information is received and the attached invoice is paid in full.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Robert C Rinaldi at (661) 392-5614.

Sincerely,

Arnaud Marjollet
Director of Permit Services

Richard W. Karg

Leonard Scandura, P.E.
Permit Services Manager

AM:rcr
Attachment

Due Date	Amount Due
1/12/2021	$ 174.00

Amount Enclosed

ATCFEE S1204133
3746 S155406 11/13/2020

SUNRISE POWER CO
12857 SUNRISE POWER RD
FELLOWS, CA 93224

SJVAPCD
34946 Flyover Court
Bakersfield, CA 93308

Facility ID	Invoice Date	Invoice Number
S3746	11/13/2020	S155406

Invoice Type
Project: S1204133

SUNRISE POWER CO
12857 SUNRISE POWER RD
FELLOWS, CA 93224

PROJECT NUMBER: 1204133

APPLICATION FILING FEES	$ 174.00
LESS PREVIOUSLY PAID PROJECT FEES APPLIED TO THIS INVOICE	$ 0.00
PROJECT FEES DUE (Enclosed is a detailed statement outlining the fees for each item.)	**$ 174.00**

Late Payment (see Rule 3010, Section 11.0 Late Fees)	
Postmarked	Total Due
After 1/12/2021 through 1/22/2021	$ 191.40
After 1/22/2021	$ 261.00
After 2/11/2021	Permits To Operate MAY BE SUSPENDED

San Joaquin Valley Air Pollution Control District

Invoice Detail

Facility ID: S3746

SUNRISE POWER CO
12857 SUNRISE POWER RD
FELLOWS, CA 93224

Invoice Nbr: S155406
Invoice Date: 11/13/2020
Page: 1

Application Filing Fees

Project Nbr	Permit Number	Description	Application Fee
S1204133	S-3746-1-13	MODIFICATION OF 160 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF GENERAL ELECTRIC FRAME 7FA, NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW-NOX COMBUSTORS, HEAT RECOVERY STEAM GENERATOR WITH DUCT FIRING, SCR, AND OXIDATION CATALYSTS (585 MW TOTAL PLANT NOMINAL RATING): INCREASE RATING	$ 87.00
S1204133	S-3746-2-13	MODIFICATION OF 160 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF GENERAL ELECTRIC FRAME 7FA, NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW-NOX COMBUSTORS, HEAT RECOVERY STEAM GENERATOR WITH DUCT FIRING, SCR, AND OXIDATION CATALYSTS (585 MW TOTAL PLANT NOMINAL RATING): INCREASE RATING	$ 87.00

Total Application Filing Fees: $ 174.00

San Joaquin Valley Unified
Air Pollution Control District

APR 1150

Implementation of Rule 2201 for SB288 Major Modifications and Federal Major Modifications

Approved By: ____Signed____		Date: March 17, 2016
	Arnaud Marjollet	Revised: September 16, 2020
	Director of Permit Services	Revised: October 01, 2020

I. Purpose

This policy is applicable to the requirements of Rule 2201.

The purpose of this policy is to provide guidance on the calculation procedures to determine if an application subject to Rule 2201 is a SB 288 Major Modification and/or a Federal Major Modification, as defined in sections 3.34 and 3.17, respectively. Additionally, for projects that are Federal Major Modifications, this policy provides guidance for determining the Federal offset quantity (used only in offset equivalency determinations).

Please note that nothing in this policy supersedes the requirements of Rule 2201, Federal New Source Review as codified on 40 CFR 51.165 and part D of Title I of the Federal Clean Air Act.

Resources:

- Federal Major Modification: 40 CFR 51.165: https://www.law.cornell.edu/cfr/text/40/51.165
- Federal Clean Air Act: https://www.epa.gov/clean-air-act-overview/clean-air-act-text
- Federal Clean Air Act under section 182 (e) (2): https://www.govinfo.gov/content/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart2-sec7511a.htm

II. Background

The SB 288 Major Modification calculation procedure is included in Rule 2201 to comply with the requirements of California SB288 which prohibited District's from relaxing requirements for Federal New Source Review (as they existed on 12/19/02) as a result of Federal NSR reform (see Appendix A).

On 12/31/02, EPA published revisions to the Federal NSR program (40 CFR 51.165), referred to as NSR Reform, which became effective on March 3, 2003. These amendments primarily changed the calculation methodology for determining if a modification at a stationary source was a major modification.

On 3/31/10, EPA published an 18-month stay of their final rulemaking regarding the treatment of fugitive emissions (that **fugitive emissions are only included in modification calculations if the stationary source is one of the specific source categories listed in 40 CFR 51.165**). Therefore, the regulations implementing Federal NSR are to be applied as they existed before this rulemaking, until EPA takes a final action or the stay expires on September 30, 2011.

Consistent with the District's longstanding interpretation and implementation of the previous version of 40 CFR 51.165 (which was silent on this issue), **fugitive emissions will be included to determine if a stationary source is major source or a modification** is an SB 288 Major Modification or a Federal Major Modification, **only if the stationary source is one of the specific source categories listed in 40 CFR 51.165**.

For oil and gas production activities, the traditional stationary source definition shall be used; the area-wide stationary source definition shall not be used.

The determination of whether various permitting actions involving new or modified emission units are part of the same project is to be performed on a case by case basis. **In general, new or modified emission units that are technically or economically dependent shall be considered one project for SB288 Major Modification and Federal Major Modification applicability (see 71 FR 54235)**. Please note that in this context, the term project has no relation to the project number assigned by the District to individual groups of applications.

Non-road engines shall not be considered in determining whether a source is major source or if a modification is a SB288 or Federal Major Modification. The Federal CAA reserves the regulation of non-road engines to Title II (National Emission Standards) of the CAA. While Title 1 (Nonattainment Areas) does not include explicit provisions to exclude non-road engine from applicability determinations, Title III (Toxics) includes a provision in the definition of stationary source that excludes "… those emissions … from a non-road engine or a non-road vehicle defined in section 216".

III. SB288 Major Modification and Federal Major Modification Applicability at Non-Major Sources

An SB 288 Modification or a Federal Major Modification for a given pollutant can only occur at a stationary source that is major for that specific pollutant. Emission increases at non-major sources cannot trigger an SB288 Major Modification or a Federal Major Modification.

New Major Source
Pursuant to 40 CFR 51.165 a(1)(iv)(A)(3), emission increases at a non-major source (or at new sources) will trigger "new" major source requirements if the emission increase for a given project is as large as the major source thresholds, i.e. the project itself would have an emission increase as large as a new major source.

Other than described above, there are no "Federal" requirements for projects at existing sources that result from a project that causes a source's potential to emit to exceed the major source threshold.

IV. SB 288 Major Modification Calculation

40 CFR 51.165 that existed on 12/19/2002 (See Appendix A) , states that for a major source, **a project is a SB 288 Major Modification if the project results in a net emission increase exceeding the SB 288 Major Modification Thresholds listed in Rule 2201**.

Under this version of 40 CFR 51.165 (12/19/2002), **a Net Emission Increase is defined as the sum of the differences between the post-project potential to emit (PE2) and the actual emissions (AE) for all new and modified emission units**.

NEI = ∑(PE2 – AE)

The project's Net Emissions Increase for each pollutant is equal to:

- **For existing emission units: the sum of the differences between the potential to emit (PE) and the actual emissions (AE)**

  Project Net Emissions Increase = ∑(PE2 – AE)

or

- **For new emission units: the sum of the potentials to emit**.

  Project Net Emissions Increase = ∑(PE2)

This calculation is done on a pollutant-by-pollutant basis and **only for those pollutants for which the source is major.**

Rule 2201
SB 288 Major Modification Thresholds

POLLUTANT	THRESHOLD (POUNDS PER YEAR)
VOC	50,000
NOx	50,000
PM10	30,000
SOx	80,000

In determining which emission units are new or modified, the definitions in the appropriate version of 40 CFR 51.165 shall be used, and not the definitions in Rule 2201.

For existing emissions unit, when determining whether a unit is included in the SB 288 Major Modification applicability calculation, only unit(s) undergoing a physical change or an actual change in the method of operation must be included. If an emission unit is not undergoing a physical change or an actual change in the method of operation, it must not be included in the SB 288 Major Modification applicability calculation.

For purposes of determining if a new or modified emission unit is part of an SB 288 Major Modification, if the annual emission increase for the emission unit when divided by 365 is less than or equal to 0.5 lb./day, such an increase shall be rounded to 0. New or modified emission units with emission increases that round to 0 shall not constitute an SB 288 Major Modification.

The process for determining if a project will result in a SB288 Major Modification consists of a two-step test:

- **The first step is to determine if the project results in a significant emission increase.** For this determination, only emission increases are counted. Emission decreases associated with the project are not counted.
- The second step is to determine if the project results in a **significant <u>net</u> emission increase**.

<u>Calculations for existing emission units:</u>

- PE: The potential to emit is the post-project potential to emit for the emission unit.
- AE: In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

Calculations for new emission units:

- The potential to emit is the post project potential to emit for the emission unit.
- The actual emissions are equal to 0.
- A replacement unit (a unit that replaces the function of an existing unit) shall be treated as an existing emission unit.

Please note that increases in fugitive emissions are only included for the source categories specified in 40 CFR 51.165.

If the project's emission increases are less than the significance thresholds, the project is not an SB 288 Major Modification and no further analysis is required. However, if the project's emission increases are above the SB288 Major Modification significance thresholds, the project results in a significant emission increase and the second step of the test must be completed.

If the project results in a significant emission increase, then the second step is to determine if all creditable emission increases and decreases within the past five years (including those projects not related to the subject project) results in a significant net emission increase. In this calculation, all creditable emission decreases and increases must be counted.

If the net emission increase is less than the significance thresholds in Table 3-5, the project is not an SB 288 Major Modification and no further analysis is required.

Alternatively, the applicant may stipulate that the project results in both a significant emission increase and significant net emission increase. In such a case, the project constitutes an SB 288 Major Modification and is subject to all applicable requirements.

V. Federal Major Modification Applicability Calculation

The calculations below are strictly to determine if a modification at a stationary source is a Federal Major Modification. For projects that are a Federal Major Modification, the Federal Offset quantity (used in the Rule 2201 Offset Equivalency Demonstration) is discussed in Section VI below.

Rule 2201 section 3.17 defines Federal Major Modification the same as "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA. Section 3.17 also states that an SB 288 Major Modification is not a Federal Major Modification if the emission increase for the project or the net emission increase for the project (calculated pursuant to 40 CFR 51.165 (a)(2)(ii)(B) through (D) and (F)) does not result in a significant emission increase as defined in Rule 2201 or the modification does not cause facility wide emissions to exceed a previously established plant wide applicability limit (PAL).

This calculation is done on a pollutant-by-pollutant basis and only for those pollutants for which the source is major.

Rule 2201 Federal Major Modification Significance Thresholds

POLLUTANT	THRESHOLD (POUNDS PER YEAR)
VOC	0
NOx	0
PM2.5	20,000 of direct PM2.5 emissions or
	80,000 of sulfur dioxide emissions or
	80,000 of nitrogen oxide emissions
PM10	30,000
SOx	80,000

In determining which emission units are new or modified, the definitions in the appropriate version of 40 CFR 51.165 shall be used, and not the definitions in Rule 2201.

For existing emissions unit, when determining whether a unit is included in the Federal Major Modification applicability calculation, only unit(s) undergoing a physical change or an actual change in the method of operation must be included. If an emission unit is not undergoing a physical change or an actual change in the method of operation, it must not be included in the Federal Major Modification applicability calculation.

The remaining discussion addresses procedures to determine if a project's emission increase or net emission increase is significant as specified in Rule 2201 section 3.17.1. This policy does not address the PAL exclusion as defined in Rule 2201 section 3.17.2.

For purposes of determining if a new or modified emission unit is part of an Federal Major Modification, if the annual emission increase (calculated using the procedures below) for the emission unit when divided by 365 is less than or equal to 0.5 lb./day, such an increase shall be rounded to 0. New or modified emission units with emission increases that round to 0 shall not constitute a Federal Major Modification.

The first step is to determine if the project itself results in a significant emission increase. In this determination, only emission increases are counted. Emission decreases associated with the project are not counted.

The second step is to determine if the project results in a significant net emission increase.

Please note that as required in the Federal Clean Air Act under section 182 (e) (2), Step 2 of the analysis shall not be performed for pollutant or their precursors for which a district is in extreme non-attainment status. For the District, this requirement applies to NOx and VOC. Therefore for NOx and VOC, only step 1 of the analysis is performed when determining Federal Major Modification applicability.

Notwithstanding the above, a facility with a project that has an emission increase in NOx or VOCs can elect to offset the emission increase at a ratio of 1.3:1 using emission reductions that occurred at the same stationary source. Such emission reductions must be surplus of all current Federally enforceable requirements, i.e. surplus at the time of use. Such projects shall not constitute a Federal Major Modification. Offsets provided pursuant to this provision may be used to satisfy offset requirements of Rule 2201.

Please note that, when performing the Federal Major Modification calculation, increases in fugitive emissions are only included for the source categories specified in 40 CFR 51.165.

1. Step 1: Project Emissions Increase Calculation

1.1. Calculation for Modification to Existing Emission Units

Replacement Unit: A replacement unit (as defined in 51.165(a)(1)(xxi) shall be treated as an existing emission unit in applicability calculations pursuant to 51.165(a)(1)(vii)(B).

- **Project Emissions Increase**

  For existing emission units, according to 40 CFR 51.165(a)(2)(ii)(C), the project's emission increase for each pollutant is equal to the sum of the differences between the projected actual emissions (PAE) and the baseline actual emissions (BAE):

  Project emissions increase = ∑(PAE – BAE)

- **Baseline Actual Emissions**

  BAE definition:
  For emission units (other than electric utility steam generating units), according to according to 40 CFR 51.165(a)(1)(xxxv)(B), **the BAE are calculated as the average, in tons/year, at which the emissions unit actually emitted during any 24-month period selected by the operator within the previous 10-year period.** For electric utility steam generating units the BAE are calculated based on any 24-month period selected by the operator within the previous 5-year period.

  Adjustments to BAE:
  BAE must be adjusted to
    - Include fugitive emissions to the extent quantifiable and emissions associated with startups, shutdowns, and malfunctions,
    - Exclude any non-compliant operation emissions.

  The evaluation shall document any such adjustments or that none adjustments were required.

There are no special provisions in determining baseline actual emissions for emission units for which offsets were previously provided.

BAE For Each Regulated Pollutant:
For a specific regulated NSR pollutant, when a project involves multiple emissions units, **only one consecutive 24-month period must be used** to determine the baseline actual emissions for all modified emissions units.

A different consecutive 24-month period can be used **for each regulated NSR pollutant.**

- **Projected Actual Emissions (PAE)**

  PAE can be calculated in 2 ways, as discussed below.

  - **PAE Determination**

    Where there is no increase in design capacity or potential to emit, the projected actual emissions (PAE) are equal to the annual emission rate at which the unit is projected to emit in any one year selected by the operator within 5 years after the unit resumes normal operation (10 years for existing units with an increase in design capacity or potential to emit).

    The source must estimate the projected actual emissions (PAE) based on all information relevant to the emission unit(s), (e.g. historical data, company's expected business activity, and highest projections of business), and provide a detailed justification of the estimate in their application. **If a justified estimate is not provided, the potential to emit (PE) for the existing emission units shall be used for this calculation**. For projects without an increase in design capacity or potential to emit, the PAE cannot exceed the pre-project potential to emit.

    - **Unused Baseline Capacity (UBC)**

      As described in 40 CFR 51.165(a)(1)(xxviii)(B), when using historical data and company's expected business activity and highest projections of business activity to determine PAE, the portion of the emissions after the project that the existing unit could have accommodated before the project (**during the same 24-month baseline period used to determine BAE)** and that are unrelated to the particular project (including emissions increases due to product demand growth) are to be excluded.

      In other words, **the difference in emissions between what the unit could have actually accommodated (legally and physically) before the project and the BAE are to be subtracted from any calculated increase, if the ability to utilize the previously unused capacity is**

not related to the current project. For the discussion below, this quantity is termed “Unused Baseline Capacity (UBC) emissions”.

Please note that the UBC can not be used in the project emissions increase calculation when PE is used for PAE.

Project emissions increase = ∑(PAE – BAE – UBC)

Please note that to determine the UBC emissions, the facility must provide a description of all legal and physical limitations on the emission unit’s utilization rate prior to the project. Such legal and physical limitations are not limited to requirements of the District permit.

The UBC emissions can not be directly assessed as the difference between the pre-project potential to emit and the baseline actual emissions.

The UBC determinaton must be made on a case-by-case basis. In determining the UBC emissions, District staff must rely on information submited by the applicant and exercise independent judgement to assess if the claimed UBC emissions are reasonable. To determine the UBC, several factors must be considered such as the degradation of an emision unit’s capacity, the ability of the unit to perform at specific capacity rate, the emission rate of the unit over time, etc.

If no information supporting the UBC emissions is provided by the applicant, UBC emissions is set to 0.

- **Otherwise, PAE = PE2**

  According to 40 CFR 51.165(a)(1)(xxviii)(B)(4), when determining PAE, in lieu of using the method described in 40 CFR 51.165 (a)(1)(xxviii)(B)(1)-(3), *Projected Actual Emissions*, the owner/operator may elect to use emissions unit’s Potential to Emit.

  If appropriate projected actual emissions are not provided by the applicant, then the emissions unit’s **Post-Project Potential to Emit (PE2)** is set to PAE:

  Project emissions increase = ∑(PE2 – BAE)

1.2. Calculation for New Emission Units

For new emission units, according to 40 CFR 51.165(a)(2)(ii)(D), the project’s emission increase for each pollutant is the sum of the potentials to emit:

The emission increase is the post-project potential to emit. Projected actual emissions cannot be used for new emission units.

BAE are equal to 0.

Project emissions increase = ∑ (PE2)

1.3. Calculation Involving Both Modified and New Emission Units

For projects involving both existing and new emission units, the emission increase for the project is calculated as the sum of the emission increases for both the existing and new emission units.

1.4. Project Emission Increases Less than Federal Major Modification Significance Thresholds

If the project's emission increases (Step 1) are less than the Federal Major Modification significance thresholds, the project is not a Federal Major Modification and no further analysis is required.

For such projects, specific requirements apply:

- Recordkeeping of actual emission is required.
- Actual emission are required to be reported to the District if actual emissions exceed the baseline actual emissions and if the actual emissions differ from the projection of actual emissions (if utilized).
- This recordkeeping and reporting requirement remains in effect for a period of 5 years (if there is no increase in capacity) or 10 years (if there is an increase in design capcity capacity) after the modification pursuant to 51.165(a)(6).

Please note that the baseline actual emissions and projeted actual emissions are not enforecable emission limits.

<u>Permit Condition (Example)</u>

When the owner/operater has estimated the projected actual emissions based on all information relevant to the emission unit(s), recordkeeping and reporting requirement is shown below:

- *If the emission unit's actual emissions exceed XX,XXX lb XXX per calendar year the permittee must report to the District the annual XXX emissions as calculated pursuant to paragraph 40 CFR 51.165(a)(6)(iii) and any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection. Such information must be submitted to the District for a period of 5 calendar years beginning the year of operation under ATC X-XX-XX-X and shall be submitted within 60 days of the end of each calendar year. [District Rule 2201] Y*

2. Step 2: Net Emission Increase Calculation

If the project's emission increases are above the significance Federal Major Modification thresholds in Table 3-1, the project results in a significant emission increase and further analysis is required, except as allowed below.

Please note that, as discussed above, under the Federal Clean Air Act, section 182 (e) (2), Step 2 of the analysis shall not be performed for pollutant or their precursors for which a district is in extreme non-attainment status. For the District this requirement applies to NOx and VOC and Step 2 of the analysis shall not be performed for these 2 criteria pollutants.

Pursuant to 40 CFR 51.165(a)(1)(vi)(A), if the project results in a significant emission increase, the creditable actual emission increases and decreases at the facility occurring during the period used to determine baseline actual emissions, within the past 5 years (including those projects not related to the subject project) must be calculated to determine if the project results in a significant net emission increase (Step 2). In this calculation, all creditable emission decreases and increases must be counted.

If the net emission increase is less than the significance thresholds, then the project is not a Federal Major Modification.

As an alternative to performing the calculation in step 2, the applicant may stipulate that the project results in both a significant emission increase and significant net emission increase. In such a case, the project constitutes a Federal major modification.

Please note that for projects that constitute a Federal Major Modification, the "emission increase" (calculated consistent with the requirements of 40 CFR 51.165) for such projects must be determined. Such emission increases are included in the District's annual offset equivalency demonstration described in Rule 2201 section 7.0).

VI. Rule 2201 BACT Requirement for SB 288 and Federal Major Modifications

Rule 2201 section 4.1.3 requires BACT for any new or modified emission unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification. This determination is made on a pollutant-by-pollutant basis.

In determining which emission units are new or modified, the definitions in the appropriate version of 40 CFR 51.165 shall be used, and not the definitions in Rule 2201.

Please note that, for modified emission units, only those undergoing a physical change or an actual change in the method of operation are subject to BACT requirement. Emission units not undergoing a physical change or an actual change in the method of operation are not subject to BACT requirement.

If a project results in an SB 288 or Federal Major Modification, only emission units that result in an emission increase(calculated as calculated above: PE – AE or PAE - BAE), require BACT. If an emission unit, that is part of a project that is an SB288 or Federal Major Modification, does not result in an emission increase (calculated pursuant to the provisions in the apprporiate version of CFR 51.165) BACT is not required for that emission unit.

VII. Federal Offset Quantities

The Federal offset quantity (FOQ) is only calculated for the pollutants for which a project is a Federal Major Modification as determined in Section V above or a New Major Source as determined in Section lll above.

Pursuant to 40 CFR 51.165(a)(3)(ii)(J), the Federal offset quantity is the sum of the annual emission changes for all new and modified emission units in a project calculated as the potential to emit after the modification (PE2) minus the actual emissions (AE) for each emission unit times the applicable federal offset ratio.

FOQ = (PE2 – AE) x Federal offset ratio

AE is defined in 40 CFR 51.165 (a)(1)(xii): In general, actual emissions as of a particular date shall equal the **average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation**. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation.

Please note that AE and BAE may be different.

- AE is the average rate at which the unit actually emitted the pollutant during a **consecutive 24-month period before the project** and which is representative of **normal source operation**,
- While BAE is calculated as the average at which the emissions unit actually emitted during **any** 24-month period selected by the operator within the previous 10-year period (5-year period for electric utility steam generating units).

Please note that for units covered by an SLC, typically there are no special calculations performed. However, if all units covered by the SLC are being modified, the total PE2 of all modified emission units is set equal to the post project SLC.

The Federal offset ratio requirement is contained in the Federal Clean Air Act (CAA), Section 182.

According the CAA 182(e), the federal offset ratio for VOC and NOx is 1.5 to 1 (due to extreme ozone non-attainment). Otherwise the federal offset ratio for PM2.5, PM10, and SOx is 1.0 to 1.

For project that triggers Federal Major Modification requirements or results in a New Major Source, the federal offset quantity shall be determined using the attached table. This table shall be included in the application review in the Federal Major Modification/Federal Offset Quantity Calculation section pursuant to APR1010. The federal offset quantity shall also be entered into the Major Modification tracking database under the “Federal Offset Quantity” heading.

Federal Offset Quantity Calculations

NOx — **Federal Offset Ratio** **1.5**

Permit No.	Actual Emissions (lb/year)	Potential Emissions (lb/year)	Emissions Change (lb/yr)
			0
			0
			0
			0
		PE2 - AE (lb/year):	0
		Federal Offset Quantity: (PE2 – AE) x 1.5	0

VOC — **Federal Offset Ratio** **1.5**

Permit No.	Actual Emissions (lb/year)	Potential Emissions (lb/year)	Emissions Change (lb/yr)
			0
			0
			0
			0
		PE2 - AE (lb/year):	0
		Federal Offset Quantity: (PE2 – AE) x 1.5	0

PM10 — **Federal Offset Ratio** **1.0**

Permit No.	Actual Emissions (lb/year)	Potential Emissions (lb/year)	Emissions Change (lb/yr)
			0
			0
			0
			0
		PE2 - AE (lb/year):	0
		Federal Offset Quantity: (PE2 – AE) x 1.0	0

PM2.5 **Federal Offset Ratio** **1.0**

Permit No.	Actual Emissions (lb/year)	Potential Emissions (lb/year)	Emissions Change (lb/yr)
			0
			0
			0
			0
		PE2 - AE (lb/year):	0
		Federal Offset Quantity: (PE2 – AE) x 1.0	0

SOx **Federal Offset Ratio** **1.0**

Permit No.	Actual Emissions (lb/year)	Potential Emissions (lb/year)	Emissions Change (lb/yr)
			0
			0
			0
			0
		PE2 - AE (lb/year):	0
		Federal Offset Quantity: (PE2 – AE) x 1.0	0

Appendix A
40 CFR 51.165 in effect on 12/19/02

Appendix A

40 CFR 51.165 in effect on 12/19/02
Used to determine if a project is an SB288 Major Modification

TITLE 40--PROTECTION OF ENVIRONMENT

CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY

PART 51--REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS--Table of Contents

Subpart I--Review of New Sources and Modifications

Sec. 51.165 Permit requirements.

(a) State Implementation Plan provisions satisfying sections 172(b)(6) and 173 of the Act shall meet the following conditions:

(1) All such plans shall use the specific definitions. Deviations from the following wording will be approved only if the State specifically demonstrates that the submitted definition is more stringent, or at least as stringent, in all respects as the corresponding definition below:

(i) Stationary source means any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Act.

(ii) Building, structure, facility, or installation means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same Major Group (i.e., which have the same two-digit code) as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0065 and 003-005-00176-0, respectively).

(iii) Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

(iv)(A) Major stationary source means:

(1) Any stationary source of air pollutants which emits, or has the potential to emit 100 tons per year or more of any pollutant subject to regulation under the Act, or

(2) Any physical change that would occur at a stationary source not qualifying under paragraph (a)(1)(iv)(A)(1) as a major stationary source, if the change would constitute a major stationary source by itself.

(B) A major stationary source that is major for volatile organic compounds shall be considered major for ozone

(C) The fugitive emissions of a stationary source shall not be included in determining for any of the purposes of this paragraph whether it is a major stationary source, unless the source belongs to one of the following categories of stationary sources:

(1) Coal cleaning plants (with thermal dryers);

(2) Kraft pulp mills;

(3) Portland cement plants;

(4) Primary zinc smelters;

(5) Iron and steel mills;

(6) Primary aluminum ore reduction plants;

(7) Primary copper smelters;

(8) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(9) Hydrofluoric, sulfuric, or nitric acid plants;

(10) Petroleum refineries;

(11) Lime plants;

(12) Phosphate rock processing plants;

(13) Coke oven batteries;

(14) Sulfur recovery plants;

(15) Carbon black plants (furnace process);

(16) Primary lead smelters;

(17) Fuel conversion plants;

(18) Sintering plants;

(19) Secondary metal production plants;

(20) Chemical process plants;

(21) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

(22) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

(23) Taconite ore processing plants;

(24) Glass fiber processing plants;

(25) Charcoal production plants;

(26) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input; and

(27) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act.

(v)(A) Major modification means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.

(B) Any net emissions increase that is considered significant for volatile organic compounds shall be considered significant for ozone.

(C) A physical change or change in the method of operation shall not include:

(1) Routine maintenance, repair and replacement;

(2) Use of an alternative fuel or raw material by reason of an order under sections 2 (a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plan pursuant to the Federal Power Act;

(3) Use of an alternative fuel by reason of an order or rule section 125 of the Act;

(4) Use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(5) Use of an alternative fuel or raw material by a stationary source which;

(i) The source was capable of accommodating before December 21, 1976, unless such change would be prohibited under any federally enforceable permit condition which was established after December 12, 1976 pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR subpart I or Sec. 51.166, or

(ii) The source is approved to use under any permit issued under regulations approved pursuant to this section;

(6) An increase in the hours of operation or in the production rate, unless such change is prohibited under any federally enforceable permit condition which was established after December 21, 1976 pursuant to 40 CFR 52.21 or regulations approved pursuant to 40 CFR part 51 subpart I or 40 CFR 51.166.

(7) Any change in ownership at a stationary source.

(8) The addition, replacement or use of a pollution control project at an existing electric utility steam generating unit, unless the reviewing authority determines that such addition, replacement, or use renders the unit less environmentally beneficial, or except:

(i) When the reviewing authority has reason to believe that the pollution control project would result in a significant net increase in representative actual annual emissions of any criteria pollutant over levels used for that source in the most recent air quality impact analysis in the area conducted for the purpose of title I, if any, and

(ii) The reviewing authority determines that the increase will cause or contribute to a violation of any national ambient air quality standard or PSD increment, or visibility limitation.

(9) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project, provided that the project complies with:

(i) The State Implementation Plan for the State in which the project is located, and

(ii) Other requirements necessary to attain and maintain the national ambient air quality standard during the project and after it is terminated.

(vi)(A) Net emissions increase means the amount by which the sum of the following exceeds zero:

(1) Any increase in actual emissions from a particular physical change or change in the method of operation at a stationary source; and

(2) Any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable.

(B) An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs before the date that the increase from the particular change occurs;

(C) An increase or decrease in actual emissions is creditable only if:

(1) It occurs within a reasonable period to be specified by the reviewing authority; and

(2) The reviewing authority has not relied on it in issuing a permit for the source under regulations approved pursuant to this section which permit is in effect when the increase in actual emissions from the particular change occurs.

(D) An increase in actual emissions is creditable only to the extent that the new level of actual emissions exceeds the old level.

(E) A decrease in actual emissions is creditable only to the extent that:

(1) The old level of actual emission or the old level of allowable emissions whichever is lower, exceeds the new level of actual emissions;

(2) It is federally enforceable at and after the time that actual construction on the particular change begins; and

(3) The reviewing authority has not relied on it in issuing any permit under regulations approved pursuant to 40 CFR part 51 subpart I or the State has not relied on it in demonstrating attainment or reasonable further progress;

(4) It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change.

(F) An increase that results from a physical change at a source occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period, not to exceed 180 days.

(vii) Emissions unit means any part of a stationary source which emits or would have the potential to emit any pollutant subject to regulation under the Act.

(viii) Secondary emissons means emissions which would occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself. For the purpose of this section, secondary emissions must be specific, well defined, quantifiable, and impact the same general area as the stationary source or modification which causes the secondary emissions. Secondary emissions include emissions from any offsite support facility which would not be constructed or increase its emissions except as a result of the construction of operation of the major stationary source of major modification. Secondary emissions do not include any emissions which come directly from a mobile source such as emissions from the tailpipe of a motor vehicle, from a train, or from a vessel.

(ix) Fugitive emissions means those emissions which could not reasonably pass through a stack, chimney, vent or other functionally equivalent opening.

(x) Significant means, in reference to a net emissions increase pr the potential of a source to emit any of the following pollutions, as rate of emissions that would equal or exceed any of the following rates:

Pollutant Emission Rate

Carbon monoxide: 100 tons per year (tpy)
Nitrogen oxides: 40 tpy
Sulfur dioxide: 40 tpy
Ozone: 40 tpy of volatile organic compounds
Lead: 0.6 tpy

(xi) Allowable emissions means the emissions rate of a stationary source calculated using the maximum rated capacity of the source (unless the source is subject to federally enforceable limits which restrict the operating rate, or hours of operation, or both) and the most stringent of the following:

(A) The applicable standards set forth in 40 CFR part 60 or 61;

(B) Any applicable State Implementation Plan emissions limitation including those with a future compliance date; or

(C) The emissions rate specified as a federally enforceable permit condition, including those with a future compliance date.

(xii)(A) Actual emissions means the actual rate of emissions of a pollutant from an emissions unit as determined in accordance with paragraphs (a)(1)(xii) (B) through (D) of this section.

(B) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal source operation. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates, and types of materials processed, stored, or combusted during the selected time period.

(C) The reviewing authority may presume that the source-specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

(D) For any emissions unit (other than an electric utility steam generating unit specified in paragraph (a)(1)(xii)(E) of this section) which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date.

(E) For an electric utility steam generating unit (other than a new unit or the replacement of an existing unit) actual emissions of the unit following the physical or operational change shall equal the representative actual annual emissions of the unit, provided the source owner or operator maintains and submits to the reviewing authority, on an annual basis for a period of 5 years from the date the unit resumes regular operation, information demonstrating that the physical or operational change did not result in an emissions increase. A longer period, not to exceed 10 years, may be required by the reviewing authority if it determines such a period to be more representative of normal source post-change operations.

(xiii) Lowest achievable emission rate means, for any source, the more stringent rate of emissions based on the following:

(A) The most stringent emissions limitation which is contained in the implementation plan of any State for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or

(B) The most stringent emissions limitation which is achieved in practice by such class or category of stationary sources. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within or stationary source. In no event shall the application of the term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under an applicable new source standard of performance.

(xiv) Federally enforceable means all limitations and conditions which are enforceable by the Administrator, including those requirements developed pursuant to 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, any permit requirements established pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR part 51, subpart I, including operating permits issued under an EPA-approved program that is incorporated into the State implementation plan and expressly requires adherence to any permit issued under such program.

(xv) Begin actual construction means in general, initiation of physical on-site construction activities on an emissions unit which are of a permanent nature. Such activities include, but are not limited to, installation of building supports and foundations, laying of underground pipework, and construction of permanent storage structures. With respect to a change in method of operating this term refers to those on-site activities other than preparatory activities which mark the initiation of the change.

(xvi) Commence as applied to construction of a major stationary source or major modification means that the owner or operator has all necessary preconstruction approvals or permits and either has:

(A) Begun, or caused to begin, a continuous program of actual on-site construction of the source, to be completed within a reasonable time; or

(B) Entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the source to be completed within a reasonable time.

(xvii) Necessary preconstruction approvals or permits means those Federal air quality control laws and regulations and those air quality control laws and regulations which are part of the applicable State Implementation Plan.

(xviii) Construction means any physical change or change in the method of operation (including fabrication, erection, installation, demolition, or modification of an emissions unit) which would result in a change in actual emissions.

(xix)Volatile organic compounds (VOC) is as defined in Sec. 51.100(s) of this part.

(xx) Electric utility steam generating unit means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

(xxi) Representative actual annual emissions means the average rate, in tons per year, at which the source is projected to emit a pollutant for the two-year period after a physical change or change in the method of operation of
a unit, (or a different consecutive two-year period within 10 years after that change, where the reviewing authority determines that such period is more representative of source operations), considering the effect any such change will have on increasing or decreasing the hourly emissions rate and on projected capacity utilization. In projecting future emissions the reviewing authority shall:

(A) Consider all relevant information, including but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under title IV of the Clean Air Act; and

(B) Exclude, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole.

(xxii) Temporary clean coal technology demonstration project means a clean coal technology demonstration project that is operated for a period of 5 years or less, and which complies with the State Implementation Plan for the State in which the project is located and other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(xxiii) Clean coal technology means any technology, including technologies applied at the precombustion, combustion, or post combustion stage, at a new or existing facility which will achieve significant reductions in air emissions of sulfur dioxide or oxides of nitrogen associated with the utilization of coal in the generation of electricity, or process steam which was not in widespread use as of November 15, 1990.

(xxiv) Clean coal technology demonstration project means a project using funds appropriated under the heading ``Department of Energy-Clean Coal Technology,'' up to a total amount of $2,500,000,000 for commercial demonstration of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency. The Federal contribution for a qualifying project shall be at least 20 percent of the total cost of the demonstration project.

(xxv) Pollution control project means any activity or project at an existing electric utility steam generating unit for purposes of reducing emissions from such unit. Such activities or projects are limited to:

(A) The installation of conventional or innovative pollution control technology, including but not limited to advanced flue gas desulfurization, sorbent injection for sulfur dioxide and nitrogen oxides controls and electrostatic precipitators;

(B) An activity or project to accommodate switching to a fuel which is less polluting than the fuel used prior to the activity or project, including, but not limited to natural gas or coal reburning, or the cofiring of natural gas and other fuels for the purpose of controlling emissions;

(C) A permanent clean coal technology demonstration project conducted under title II, sec. 101(d) of the Further Continuing Appropriations Act of 1985 (sec. 5903(d) of title 42 of the United States Code), or subsequent appropriations, up to a total amount of $2,500,000,000 for commercial demonstration of clean coal technology, or similar projects funded through appropriations for the Environmental Protection Agency; or

(D) A permanent clean coal technology demonstration project that constitutes a repowering project.

(2) Each plan shall adopt a preconstruction review program to satisfy the requirements of sections 172(b)(6) and 173 of the Act for any area designated nonattainment for any national ambient air quality standard under 40 CFR 81.300 et seq. Such a program shall apply to any new major stationary source or major modification that is major for the pollutant for which the area is designated nonattainment, if the stationary source or modification would locate anywhere in the designated nonattainment area.

(3)(i) Each plan shall provide that for sources and modifications subject to any preconstruction review program adopted pursuant to this subsection the baseline for determining credit for emissions reductions is the emissions limit under the applicable State Implementation Plan in effect at the time the application to construct is filed, except that the offset baseline shall be the actual emissions of the source from which offset credit is obtained where;

(A) The demonstration of reasonable further progress and attainment of ambient air quality standards is based upon the actual emissions of sources located within a designated nonattainment area for which the preconstruction review program was adopted; or

(B) The applicable State Implementation Plan does not contain an emissions limitation for that source or source category.

(ii) The plan shall further provide that:

(A) Where the emissions limit under the applicable State Implementation Plan allows greater emissions than the potential to emit of the source, emissions offset credit will be allowed only for control below this potential;

(B) For an existing fuel combustion source, credit shall be based on the allowable emissions under the applicable State Implementation Plan for the type of fuel being burned at the time the application to construct is filed. If the existing source commits to switch to a cleaner fuel at some future date, emissions offset credit based on the allowable (or actual) emissions for the fuels involved is not acceptable, unless the permit is conditioned to require the use of a specified alternative control measure which would achieve the same degree of emissions reduction should the source switch back to a dirtier fuel at some later date. The reviewing authority should ensure that adequate long-term supplies of the new fuel are available before granting emissions offset credit for fuel switches,

(C)(1) Emissions reductions achieved by shutting down an existing source or curtailing production or operating hours below baseline levels may be generally credited if such reductions are permanent, quantifiable, and federally enforceable, and if the area has an EPA-approved attainment plan. In addition, the shutdown or curtailment is creditable only if it occurred on or after the date specified for this purpose in the plan, and if such date is on or after the date of the most recent emissions inventory used in the plan's demonstration of attainment. Where the plan does not specify a cutoff date for shutdown credits, the date of the most recent emissions inventory or attainment demonstration, as the case may be, shall apply. However, in no event may credit be given for shutdowns which occurred prior to August 7, 1977. For purposes of this paragraph, a permitting authority may choose to consider a prior shutdown or curtailment to have occurred after the date of its most recent emissions inventory, if the inventory explicitly includes as current existing emissions the emissions from such previously shutdown or curtailed sources.

(2) Such reductions may be credited in the absence of an approved attainment demonstration only if the shutdown or curtailment occurred on or after the date the new source permit application is filed, or, if the applicant can establish that the proposed new source is a replacement for the shutdown or curtailed source, and the cutoff date provisions of Sec. 51.165(a)(3)(ii)(C)(1) are observed.

(D) No emissions credit may be allowed for replacing one hydrocarbon compound with another of lesser reactivity, except for those compounds listed in Table 1 of EPA's ``Recommended Policy on Control of Volatile Organic Compounds'' (42 FR 35314, July 8, 1977; (This document is also available from Mr. Ted Creekmore, Office of Air Quality Planning and Standards, (MD-15) Research Triangle Park, NC 27711.))

(E) All emission reductions claimed as offset credit shall be federally enforceable;

(F) Procedures relating to the permissible location of offsetting emissions shall be followed which are at least as stringent as those set out in 40 CFR part 51 appendix S section IV.D.

(G) Credit for an emissions reduction can be claimed to the extent that the reviewing authority has not relied on it in issuing any permit under regulations approved pursuant to 40 CFR part 51 subpart I or the State has not relied on it in demonstration attainment or reasonable further progress.

(4) Each plan may provide that the provisions of this paragraph do not apply to a source or modification that would be a major stationary source or major modification only if fugitive emission to the extent quantifiable are considered in calculating the potential to emit of the stationary source or modification and the source does not belong to any of the following categories:

(i) Coal cleaning plants (with thermal dryers);

(ii) Kraft pulp mills;

(iii) Portland cement plants;

(iv) Primary zinc smelters;

(v) Iron and steel mills;

(vi) Primary aluminum ore reduction plants;

(vii) Primary copper smelters;

(viii) Municipal incinerators capable of charging more than 250 tons of refuse per day;

(ix) Hydrofluoric, sulfuric, or citric acid plants;

(x) Petroleum refineries;

(xi) Lime plants;

(xii) Phosphate rock processing plants;

(xiii) Coke oven batteries;

(xiv) Sulfur recovery plants;

(xv) Carbon black plants (furnace process);

(xvi) Primary lead smelters;

(xvii) Fuel conversion plants;

(xviii) Sintering plants;

(xix) Secondary metal production plants;

(xx) Chemical process plants;

(xxi) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

(xxii) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

(xxiii) Taconite ore processing plants;

(xxiv) Glass fiber processing plants;

(xxv) Charcoal production plants;

(xxvi) Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input;

(xxvii) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act.

(5) Each plan shall include enforceable procedures to provide that:

(i) Approval to construct shall not relieve any owner or operator of the responsibility to comply fully with applicable provision of the plan and any other requirements under local, State or Federal law.

(ii) At such time that a particular source or modification becomes a major stationary source or major modification solely by virtue of a relaxation in any enforcement limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of regulations approved pursuant to this section shall apply to the source or modification as though construction had not yet commenced on the source or modification;

(b)(1) Each plan shall include a preconstruction review permit program or its equivalent to satisfy the requirements of section 110(a)(2)(D)(i) of the Act for any new major stationary source or major modification as defined in paragraphs (a)(1) (iv) and (v) of this section. Such a program shall apply to any such source or modification that would locate in any area designated as attainment or unclassifiable for any national ambient air quality standard pursuant to section 107 of the Act, when it would cause or contribute to a violation of any national ambient air quality standard.

(2) A major source or major modification will be considered to cause or contribute to a violation of a national ambient air quality standard when such source or modification would, at a minimum, exceed the following significance levels at any locality that does not or would not meet the applicable national standard:

Pollutant	Averaging time (hours)				
	Annual	24	8	3	1
SO2	1.0 g/m\3\.	eq>g/m\3\.		eq>g/m\3\.	
PM10	1.0 g/m\3\.	eq>g/m\3\.			
NO2	1.0 g/m\3\.				
CO	....		0.5 mg/m\3\..........	....	2 mg/m\3\

(3) Such a program may include a provision which allows a proposed major source or major modification subject to paragraph (b) of this section to reduce the impact of its emissions upon air quality by obtaining sufficient emission reductions to, at a minimum, compensate for its adverse ambient impact where the major source or major modification would otherwise cause or contribute to a violation of any national ambient air quality standard. The plan shall require that, in the absence of such emission reductions, the State or local agency shall deny the proposed construction.

(4) The requirements of paragraph (b) of this section shall not apply to a major stationary source or major modification with respect to a particular pollutant if the owner or operator demonstrates that, as to that pollutant, the source or modification is located in an area designated as nonattainment pursuant to section 107 of the Act.

[51 FR 40669, Nov. 7, 1986, as amended at 52 FR 24713, July 1, 1987; 52 FR 29386, Aug 7, 1987; 54 FR 27285, 27299 June 28, 1989; 57 FR 3946, Feb. 3, 1992; 57 FR 32334, July 21, 1992]

APPENDIX C RESPONSE TO NOTICE OF INCOMPLETE APPLICATION, SJVAPCD MARCH 5, 2021

Sunrise Power Company, LLC

March 5, 2021

Mr. Robert Rinaldi
Permit Services
San Joaquin Valley Air Pollution Control District
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244

RE: Notice of Incomplete Application
Facility Number: S-3746
Project Number: S-1204133

Dear Mr. Rinaldi:

Sunrise Power Company, LLC (Sunrise) has addressed San Joaquin Valley Air Pollution Control District (SJVAPCD) Notice of Incomplete Application dated November 17, 2020 in response to the Authority to Construct (ATC) application for the Sunrise Power Improvement Project. The proposed project entails the installation of a hot gas path upgrade in each of the combustion turbine generator (CTG) which will increase the fuel use, increase the operating temperatures, increase the net output by as much as 49 megawatts (MW), and increase the efficiency of the gas turbines. Sunrise filed the ATC application on October 26, 2020 and anticipates completing the project, if approved, in time for the summer of 2023. Sunrise has addressed information requests for Actual Emissions (AE) and Projected Actual Emissions (PAE) below.

AE for Each CTG

SJVAPCD has requested Actual Emissions (AE) for each Combustion Turbine Generator (CTG) over the prior 5 years (January 2016 through December 2020) on a monthly basis in an Excel spreadsheet file, consistent with Application Review (APR) Policy 1150 step V.1, 1.1 for steam electricity generating facility.[1] Sunrise has represented this baseline calculation as the Baseline Actual Emissions (BAE) as outlined in District APR Policy 1150 titled "Implementation of Rule 2201 for SB288 Major Modification and Federal Major Modifications." Historical pollutant emissions and the BAE are presented in Table 1. We are seeking approval of a nonconsecutive 24-month period for the BAE. For the AE calculations as described in "Calculations for existing emissions units" on page APR 1150-4, the reviewing authority has the discretion to allow "...the use of a different time period upon a determination that a more representative normal source operation." The split, 24-month period in the BAE calculation for oxides of nitrogen (NOx) as an example is represented by 12 months from August 2019 to July 2020 and 12 months from June 2017 to May 2018. Once a baseline period is determined for one unit the same baseline period is used for the second unit for the respective pollutants. Different baseline periods were determined for each pollutant. We are seeking this split 24-month baseline period as representative of normal source operations, since the more likely baseline period would have been the recent 2 years of operations if not for an approximate 5 month unplanned/extended plant outage from late January 2019 to June 2019. The outage was due to electrical faults in the steam turbine generator field, rendering the

[1] The referenced APR 1150 is the October 1, 2020 revision which was included with the Incomplete Notice.

gas turbines and steam turbine unavailable while repairs were made. This unplanned/extended outage eliminates 2019 and 2020 emissions for baseline calculations if a consecutive 24-month baseline must be used. The gas turbines were capable of operating (i.e., not damaged) and would have otherwise operated and contributed to the baseline, but for the unavailability of the steam turbine. Operations during 2019 and 2020 are not only recent but are representative of how Sunrise has been dispatched for long durations of baseload operations coupled with multi-start, shorter duration runs during the respective months. We have also included a 24-month consecutive baseline period (NOx example from June 2015 to May 2017) as an alternate, but not preferred BAE in Attachment A.

Sunrise estimated the BAE for NOx, carbon monoxide (CO) and sulfur oxides (SOx) from the Continuous Emission Monitoring System (CEMS) reports. The BAE for particulate matter 10 micrometers in diameter and smaller ($PM_{10}/PM_{2.5}$) and volatile organic compounds (VOC) emissions are calculated using the source test emission factors for $PM_{10}/PM_{2.5}$ and VOC and from fuel use recorded for 2015 to 2020.

PAE for Each CTG

SJVAPCD has requested the PAE for each CTG for a 12-month period as defined in the SJVAPCD APR Policy 1150. Sunrise has presented in Table 2 the estimated post-project projected emissions that would apply for the 10-year post-project monitoring period per the policy. Sunrise's PAE, according to 40 CFR 51.165(a)(1)(xxviii)(B)(1), is based on all relevant information, including but not limited to, historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity. Sunrise's PAE represents an estimated annual "up to" emissions based on a projection of startup and shutdown events and normal operations from 2023 through 2032. Many factors affect the business activity for projected future operations. Sunrise, as an efficient combined cycle plant that supports California's grid regionally (i.e., to the north and south), is expected to operate at similar capacity factors (i.e., plant output vs. the total plant output capacity) in the future. However, more startups and shutdowns are anticipated in the future as Sunrise backstops the increasing amount of renewables that will come onto the grid; yet efficient baseload-capable generation like Sunrise may support the grid for extended dispatches as the California electricity system responds to the future retirement of Diablo Canyon nuclear plant in the 2024-2025 timeframe. Sunrise's efficiency and design as a combined cycle plant will enable Sunrise to continue to provide baseload level support to the grid, but we expect the grid coordinator will also dispatch it more often for shorter durations to support changing renewable output. Table 2 summarizes the estimated "up to" emissions, which profiles, as an example, 220 startups and shutdowns per year and a capacity factor as high as 86% capacity factor. This projection is consistent with the dispatch trends we have seen for Sunrise where startups have increased to over 130 per year, including as much as 151 startup and shutdowns on average, per turbine, in a year while achieving capacity factors of 72-86%.

The PAE per pollutant (NOx, CO, SOx, PM, and VOCs) have estimated for startup and shutdowns and for normal operations with and without duct burner operations. Sunrise estimates the duct burners in be operation at full capacity for each CTG approximately 50% of the time. The PAE for NOx, CO and SOx startup and shutdown emissions are based on actual CEMS data averaged from startup (cold, warm and hot) and shutdown events during the BAE periods. The PAE for PM and VOC startup and shutdown emissions are estimated from CEMS fuel flow data and source test data (for emission factors) during the BAE periods. The PAE for NOx and CO during normal operations per turbine, including with duct burners on and off, have been estimated based on model runs following company proprietary models and

General Electric supplied data for the turbine modification package. The PAE for SOx and PM during normal operations are based on CEMS data used to calculate the annual average emissions during the BAE periods, but with an increase of 4.5% due to the approximate 4.5% increase in fuel input per turbine post-project due to the turbine modification package. The PAE for VOCs during normal operations are based on source test emission factors during the BAE period, but without an assumed increase in the VOCs emissions rate due to higher fuel use post-project, since the 4.5% increase in fuel input per turbine is offset by a corresponding decrease in VOC emissions rate from higher turbine operating temperatures that contribute to improved catalyst conversion of VOCs.

Unused Baseline Capacity (UBC)

Sunrise has estimated UBC or otherwise referred to as "excludable emissions" that shall be subtracted from the PAE as unused capacity that is unrelated to the uprate project, the basis of which is described in APR 1150 and from 40 CFR 51.165(a)(1)(xxviii)(B). Sunrise is using historical operating data (CEMS, source test, fuel use) and the projected business activity, including an estimate of the highest projections of business activity to estimate its PAE as outlined in the regulation. The portion of projected emissions after the uprate project that CTG 1 and 2 that could have been accommodated before the uprate project and unrelated to the uprate project during the same 24-month baseline periods used to calculate the BAE (note – Sunrise has proposed split 24-month BAE period in Table 1 and presented as an alternative, a non-preferred 24-month consecutive BAE period in Attachment A) are to be excludable. Sunrise has calculated two UBC-associated emissions to be excluded from the PAE: (1) the aggregate difference between the monthly emissions during the BAE period and the highest achieved emissions during a single month during the BAE period for the respective CTGs, since the respective CTGs could have operated at the highest achieved emissions during each month of the BAE period; this unused capacity was achievable pre-project, the exclusion of which would not be due to the uprate project; and (2) the difference in startup and shutdown emissions calculated for the BAE period and the associated startup and shutdown emissions for the projected startups/shutdowns in the PAE, since the CTGs could have achieved the number of projected startups/shutdowns pre-project (i.e., there is not a permit condition limiting the number of annual startups), but did not. The estimated startups/shutdowns for the PAE calculation are primarily the outcome of how the CAISO utilizes electricity generation assets like Sunrise to balance against renewable generation connected to the grid. The two UBC-associated emissions to be excluded from the PAE are summarized in Tables 3 and 4.

Summary of Project Emissions Increase

Tables 1-4 present the BAE, PAE and UBC calculations. Table 5 summarizes the Project Emissions Increase (PEI) for the estimated annual emissions post-project. As discussed above, Sunrise estimates the PAE to be the total emissions from the CTGs starting more than 200 times each and operating at an 80 to 90% capacity factor. The PAE, reduced by the excludable emissions (UBC), will be less than the BAE, indicating that the uprate project will result in a decrease in emissions (i.e., PEI <0) for NOx, SOx, VOCs and PM. The PEI for CO is estimated to be >0, but the less than the NSR threshold for a major modification. The Sunrise Power Improvement project will be a minor modification.

Unpaid Application Fee

Sunrise paid the application filing fee of $174.00, satisfying the last request in the Notice of Incomplete application.

Please contact George Piantka at george.piantka@nrg.com or (760) 707-6833 or Scott Seipel at scott.seipel@nrg.com or (99) 648-5008, if you have any questions regarding this response to the Notice of Incomplete application.

Sincerely,

David King
Plant Manager

Enclosures:

Table 1 – Historical Emissions Data and Baseline Actual Emissions
Table 2 – Projected Actual Emissions
Table 3 – Unused Baseline Capacity from Monthly Operations
Table 4 – Unused Baseline Capacity from Startup Events Above Baseline Period Events
Table 5 – Project Emissions Increase
Attachment A – Alternate Baseline Actual Emissions (24-month consecutive period)
Attachment B – Alternate Unused Baseline Capacity from Monthly Operations
Attachment C – Alternate Unused Baseline Capacity from Startup Events Above Baseline Period Events
Attachment D – Alternate Project Emissions Increase Based on 24 Month Baseline Actual Emissions

San Joaquin Valley
Unified Air Pollution Control District

Certification of Truth and Accuracy

Company Name: SUNRISE POWER COMPANY	Facility ID: S - 3746

I declare, under penalty of perjury under the laws of the state of California that based on information and belief formed after reasonable inquiry, the statements and information provided in the document are true, accurate, and complete:

Signature of Responsible Official

March 5, 2021
Date

David King
Name of Responsible Official (please print)

Plant Manager
Title of Responsible Official (please print)

TABLES

Table 1: Baseline Actual Emissions - Two 12 Month Periods

	Monthly	UNIT 1					UNIT 2					
	Totals	CO	NOx	SO2	PM	VOC	CO	NOx	SO2	PM	VOC	Comments
	January	629.1	4815.7	687.5	3222.2	920.6	498.2	5654.4	679.2	3749.0	908.8	
	February	2.2	3.6	0.1	0.6	0.2	2.6	2.8	0.1	0.3	0.1	Maintenance on Steam Turbine Generator Rewind
	March	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Maintenance on Steam Turbine Generator Rewind
	April	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Maintenance on Steam Turbine Generator Rewind
	May	231.4	902.4	112.8	526.1	150.3	177.1	950.4	106.1	587.1	142.3	
2015	June	923.4	5230.8	684.4	7453.3	1261.3	608.0	5062.5	676.0	5335.3	1135.2	
	July	1007.6	5327.0	698.2	7592.6	1284.9	569.3	5249.8	688.2	5437.0	1156.8	
	August	1602.0	5055.0	711.8	7732.8	1308.6	724.2	5248.1	681.4	5352.1	1138.7	
	September	1460.6	4693.9	694.0	7539.7	1276.0	762.4	5278.1	688.2	5410.2	1151.1	
	October	1764.5	4953.8	726.0	7877.7	1333.2	611.0	5410.7	704.2	5524.7	1175.5	
	November	740.2	4559.0	654.7	7139.9	1208.3	360.5	5179.6	641.7	5066.8	1078.0	
	December	793.1	4781.6	681.2	7421.7	1256.0	442.8	5521.9	672.8	5276.0	1122.5	
	January	506.5	4425.6	639.3	6988.9	1182.7	420.0	5265.2	636.6	4988.6	1061.4	
	February	408.1	3910.1	564.5	6172.1	1044.5	394.8	4613.5	559.4	4392.6	934.6	
	March	279.3	1799.1	217.9	2382.1	403.1	401.9	1876.3	209.3	1638.0	348.5	Annual outage - Routine
	April	509.5	3678.4	499.9	5433.0	919.4	579.6	3979.2	475.4	3735.0	794.7	
	May	522.5	4199.5	579.5	6330.6	1071.3	537.6	4536.3	557.9	4391.6	934.4	
2016	June	895.8	4576.5	669.3	2566.8	111.6	783.0	5100.2	655.6	7453.6	109.6	
	July	1128.7	4952.6	733.6	2821.6	122.7	1096.0	5596.8	730.3	8283.9	121.8	
	August	1231.7	5441.7	759.3	2928.2	127.3	1645.8	5799.5	755.3	8593.9	126.4	
	September	1047.2	4842.3	714.1	2754.8	119.8	1027.6	5431.7	708.8	8045.7	118.3	
	October	1200.8	5053.9	744.9	2862.3	124.4	1632.5	5654.5	737.3	8371.3	123.1	
	November	828.4	4480.8	654.2	2526.0	109.8	1256.3	4589.5	577.0	6558.1	96.4	
	December	1066.6	4263.7	581.6	2243.0	97.5	1442.8	4644.7	560.0	6381.0	93.8	
	January	968.8	4950.7	613.9	2360.6	102.6	1430.9	4957.6	591.4	6745.2	99.2	
	February	906.0	2199.8	226.4	870.5	37.8	1199.0	2130.6	200.7	2274.5	33.4	
	March	1143.9	2508.6	229.3	894.1	38.9	1069.3	2449.0	198.8	2253.4	33.1	
	April	1145.9	2464.6	219.9	849.8	36.9	870.7	2239.3	186.1	2108.0	31.0	HGP Maintenance - Burner Change Out
	May	1222.0	3719.0	439.2	1690.2	73.5	153.8	140.2	5.7	64.4	0.9	HGP Maintenance - Burner Change Out
2017	June	1067.9	4470.0	554.7	7635.5	1955.4	525.7	4766.3	520.4	4879.3	1742.6	
	July	1563.3	4940.4	725.0	9948.5	2547.8	1251.4	5961.9	715.9	6679.9	2385.7	
	August	1665.7	4753.8	701.4	9614.1	2462.2	1193.2	5855.4	701.5	6551.5	2339.8	
	September	1302.0	4265.1	601.9	8279.1	2120.2	1226.8	5310.0	612.3	5729.6	2046.3	
	October	1647.2	4835.8	707.9	9697.2	2483.4	1006.0	5785.7	694.2	6493.1	2319.0	
	November	1595.1	4649.8	683.5	9362.1	2397.6	752.8	5582.1	672.9	6296.3	2248.7	
	December	1622.5	4843.0	692.6	9509.7	2435.4	964.2	5943.6	673.7	6301.3	2250.5	
	January	304.5	623.0	75.0	1026.6	262.9	966.5	3098.5	316.9	2954.5	1055.2	Annual outage - Routine
	February	0.0	0.0	0.0	0.0	0.0	1563.8	4964.0	523.4	4892.2	1747.2	Major Maintenance On GT-1 Rotor
	March	939.5	1699.5	162.3	2245.6	575.1	1341.1	5643.0	623.9	5833.8	2083.5	Major Maintenance On GT-1 Rotor
	April	1683.1	4641.7	475.6	6501.6	1665.0	1357.5	3844.9	450.1	4205.6	1502.0	
	May	1689.4	4414.1	420.1	5780.7	1480.4	1586.8	3564.3	388.6	3635.4	1298.4	
2018	June	1314.9	4346.4	452.5	1061.9	1592.8	1019.2	3538.9	414.1	1241.2	1448.1	
	July	1466.7	4651.4	501.3	1176.1	1764.2	1164.7	3707.8	491.1	1472.7	1718.1	
	August	1858.1	4283.9	445.0	1041.0	1561.5	1168.7	3294.3	399.7	1200.4	1400.4	
	September	1920.0	5402.7	637.3	1499.1	2248.6	1140.8	4598.9	636.3	1911.6	2230.2	
	October	2338.9	5340.8	604.0	1411.8	2117.7	1451.9	4643.3	589.8	1771.4	2066.6	
	November	1782.9	4339.5	658.3	1545.7	2318.5	1172.4	4701.3	654.6	1964.2	2291.6	
	December	820.3	4769.5	618.6	1448.2	2172.3	673.3	5401.5	627.6	1887.0	2201.5	
	January	1337.3	4074.9	502.2	1174.9	1762.4	1711.0	4326.2	485.8	1457.4	1700.3	
	February	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Major Maintenance on Steam Turbine Generator
	March	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Major Maintenance on Steam Turbine Generator
	April	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Major Maintenance on Steam Turbine Generator
	May	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Major Maintenance on Steam Turbine Generator

Table 1: Baseline Actual Emissions - Two 12 Month Periods

	Monthly	UNIT 1					UNIT 2					
	Totals	**CO**	**NOx**	**SO2**	**PM**	**VOC**	**CO**	**NOx**	**SO2**	**PM**	**VOC**	**Comments**
2019	June	1295.0	847.6	66.5	581.1	234.7	640.8	709.6	51.7	477.4	182.3	Major Maintenance on Steam Turbine Generator
	July	1901.8	5589.0	648.1	6709.2	2272.5	1497.8	4525.1	629.5	5778.2	2206.2	
	August	2416.4	6150.1	707.5	7372.4	2497.1	1929.5	5721.4	696.5	6423.4	2452.6	
	September	2456.4	5759.3	662.7	6857.7	2322.8	1618.6	3685.7	547.3	5019.3	1916.5	
	October	2713.9	5704.0	617.6	6400.1	2167.8	2251.1	4737.9	658.7	6038.6	2305.7	
	November	2777.8	6396.1	745.4	7732.9	2619.2	1883.2	5700.0	692.7	6368.7	2431.7	
	December	2588.7	5894.6	720.1	7455.9	2525.4	2008.7	4983.1	716.5	6567.1	2507.4	
2020	January	2220.6	5275.0	665.2	5773.5	2331.6	2183.2	4434.4	660.8	6064.0	2315.3	
	February	2576.7	5050.0	570.6	4989.9	2015.1	1819.9	3743.5	577.6	5309.9	2027.4	
	March	1162.5	2815.5	306.5	2660.8	1074.6	905.8	1211.3	138.5	1267.7	484.0	Annual outage - Routine
	April	2109.8	4060.1	391.6	3397.1	1371.9	3029.9	3896.7	484.8	4471.2	1707.2	
	May	2131.2	2469.5	233.0	2021.9	816.5	2170.5	1882.4	240.5	2206.2	842.4	
	June	3341.8	5191.8	544.7	5626.3	1814.9	3440.4	4327.5	529.7	4506.5	1767.2	
	July	3053.9	5630.7	669.6	6952.2	2242.6	3463.4	5688.3	668.5	5716.4	2241.7	
	August	3215.1	4894.0	539.2	5604.5	1807.9	3343.4	4260.9	517.1	4397.5	1724.5	
	September	2384.5	4975.6	585.1	6061.4	1955.3	3584.4	4648.0	663.9	5673.9	2225.0	
	October	2838.1	5261.1	609.4	6340.9	2045.5	4021.0	5412.8	660.8	5620.0	2203.9	
	November	2308.2	5263.3	625.3	6484.2	2091.7	2759.5	5324.1	625.4	5326.2	2088.7	
	December	1724.6	4169.7	524.5	5434.6	1753.1	1870.0	4538.5	527.2	4481.7	1757.5	
	Maximum Month Lbs	3341.8	6396.1	759.3	9948.5	2619.2	4021.0	5961.9	755.3	8593.9	2507.4	
	Primary 12 Months Lbs	29931.3	60396.6	7457.9	41381.0	23829.4	32730.0	50012.3	7340.2	74589.9	22963.6	
	Secondary 12 Months Lbs	17151.2	44136.2	6834.4	79600.7	20385.5	15351.1	60319.8	6612.1	64452.6	23018.8	
	Sum 24 Months Lbs	47082.5	104532.8	14292.3	120981.6	44215.0	48081.1	110332.1	13952.3	139042.5	45982.4	
	Tons	23.5	52.3	7.1	60.5	22.1	24.0	55.2	7.0	69.5	23.0	
						2 Units Tons	47.6	107.4	14.1	130.0	45.1	

Facility Baseline Actual Emissions - 12 Months				
CO	**NOx**	**SO2**	**PM**	**VOC**
23.8	**53.7**	**7.1**	**65.0**	**22.5**

Table 2: Post Uprate - Projected Actuals Emissions & Project Emissions Increase (Two 12 Months BAE)

GT - 1	Sunrise Annual Emission Calculations				Annual CF 86%		GT Starts 220		Duct Burner Usage 50%		
		NOx		CO		SOx		VOC		PM	
	Starts	lb/SU -SD	Tons/yr	lb/SU -SD	Tons/yr	lb/SU -SD	Tons/yr	lb/SU -SD	Tons/yr	lb/SU -SD	Tons/yr
Cold Start /SD - 5 hr	52	113.4	2.9	195.2	5.1	2.3	0.1	4.9	0.1	16.8	0.4
Warm Start / SD - 3 hr	84	44.1	1.9	38.3	1.6	2.2	0.1	4.6	0.2	19.0	0.8
Hot Start /SD - 2 hr	84	36.7	1.5	36.4	1.5	1.3	0.1	4.7	0.2	8.0	0.3
Total			6.3		8.2		0.2		0.5		1.6
GT-2		NOx		CO		SOx		VOC		PM	
	Starts	lb/SU -SD	Tons/yr	lb/SU -SD	Tons/yr	lb/SU -SD	Tons/yr	lb/SU -SD	Tons/yr	lb/SU -SD	Tons/yr
Cold Start /SD - 2 hr	52	36.7	1.0	36.4	0.9	1.3	0.0	4.7	0.1	8.0	0.2
Warm Start / SD - 2 hr	84	36.7	1.5	36.4	1.5	1.3	0.1	4.7	0.2	8.0	0.3
Hot Start /SD - 2 hr	84	36.7	1.5	36.4	1.5	1.3	0.1	4.7	0.2	8.0	0.3
Total			4.0		4.0		0.1		0.5		0.9
GT-1 & GT-2	Hours	Lb/hr	Tons/yr	Lb/hr	Tons/yr	Lb/hr	Tons/yr	Lb/hr	Tons/yr	Lb/hr	Tons/yr
Operation w/ DB	3597	14.1	25.3	17.3	31.1	1.9	3.5	6.0	10.8	17.9	32.2
Operation wo/ DB*	4078	12.4	25.4	9.3	19.0	1.9	4.0	6.0	12.2	17.9	36.5
Total			50.7		50.1		7.4		23.0		68.7
Total GT-1 & GT-2	Projected Annual Emissions in Tons		61.1		62.3		7.8		24.1		71.1
	12 Mo	BAE	53.7		23.8		7.1		22.5		65.0
	Max Mo	UBC 1	13.1		16.3		1.5		4.9		23.3
	Starts	UBC 2	6.0		5.2		0.2		0.4		2.0
	PEI=PAE-BAE-UBC1-UBC2		-11.7		17.0		-1.0		-3.8		-19.1
	Annual Permit Limits Tons		155.7		254.0		12.1		43.8		134.8

Note

Assume both units start Unit 1 is lead unit Unit 2 is lag Unit

Operation emission rate (lb/hr) is for 2 GT's operating

UBC1 Unused Baseline Capacity - Difference of maximum month vs actual normal monthly emissions, 24 month period.

UBC2 Unused Baseline Capacity - Difference of actual starts during 24 month baseline versus project 220 starts.

CEMS Average Data

CEMS Fuel Flow and Source Test MDL applied

CEMS Fuel Flow and Source Test Rate Applied

Source test value. No increase due to higher operating temperature and catalyst conversion.

Annual emissions +4.5% based on fuel use

Modeled Emissions Rate

* Operation wo/DB - includes a correction factor of 13.4% to achieve maximum MW output

Table 3: UBC - Two 12 Month BAE

	UNIT 1						UNIT 2				
	CEMS			Emissions Factor from Source Testing						Emissions Factor from Source Testing	
	CO	NOx	SO2	PM	VOC		CO	NOx	SO2	PM	VOC
Month 1	753.1	246.0	104.6	2,495.2	346.8	Month 1	2,012.3	240.5	113.6	4,201.3	301.2
Month 2	1,121.2	636.8	78.1	2,355.9	122.1	Month 2	1,837.8	2,276.2	82.5	0.0	54.9
Month 3	765.1	692.0	119.9	2,215.7	296.4	Month 3	2,201.2	1,224.0	118.6	4,858.9	591.0
Month 4	0.0	0.0	194.8	2,408.8	451.5	Month 4	0.0	261.9	195.9	4,202.3	201.8
Month 5	1,232.0	501.5	0.0	2,070.8	0.0	Month 5	991.1	978.8	0.0	1,140.3	75.8
Month 6	1,210.6	1,121.0	259.4	2,808.5	93.8	Month 6	1,850.6	1,527.5	279.9	310.0	0.0
Month 7	0.0	1,346.1	179.8	2,526.8	287.6	Month 7	580.6	2,218.4	197.4	0.0	192.1
Month 8	287.9	0.0	90.0	2,959.6	604.1	Month 8	557.7	0.0	99.7	548.2	480.0
Month 9	126.7	2,336.0	25.7	3,776.4	0.0	Month 9	677.7	2,065.2	25.0	222.6	0.0
Month 10	957.3	3,926.6	0.0	0.0	1,247.3	Month 10	436.6	4,079.5	0.0	2,035.8	800.3
Month 11	503.7	1,204.2	45.2	4,515.5	1,802.7	Month 11	0.0	1,634.4	46.4	2,212.9	1,665.1
Month 12	1,033.6	765.3	14.4	3,617.9	804.3	Month 12	1,261.5	273.6	18.0	1,848.7	740.2
tpy	**4.0**	**6.4**	**0.6**	**15.9**	**3.0**	**tpy**	**6.2**	**8.4**	**0.6**	**10.8**	**2.6**
Month 1	0.0	1,926.0	51.8	2,313.0	663.8	Month 1	0.0	1,195.6	58.8	3,714.6	764.8
Month 2	0.0	1,455.7	96.6	0.0	71.4	Month 2	0.0	0.0	208.0	1,914.0	121.8
Month 3	1,658.7	1,642.2	141.7	334.4	157.1	Month 3	2,663.5	106.5	96.6	2,042.4	167.6
Month 4	1,652.5	2,131.0	13.9	1,669.4	499.0	Month 4	2,434.3	651.9	62.6	2,864.3	461.1
Month 5	2,026.9	1,560.3	39.2	251.3	135.8	Month 5	3,001.8	176.2	38.8	2,100.8	188.5
Month 6	1,875.1	1,746.2	94.1	586.4	221.6	Month 6	2,856.3	379.8	94.4	2,297.6	258.8
Month 7	1,483.8	1,553.1	188.7	438.8	183.8	Month 7	2,852.4	18.3	177.6	2,292.6	257.0
Month 8	1,421.8	0.0	0.0	0.0	0.0	Month 8	2,880.3	0.0	0.0	0.0	0.0
Month 9	1,002.9	0.0	367.7	0.0	0.0	Month 9	2,569.1	0.0	270.5	0.0	0.0
Month 10	1,558.9	0.0	526.3	0.0	0.0	Month 10	2,848.6	0.0	514.8	0.0	0.0
Month 11	2,521.6	1,754.4	214.6	3,446.9	954.2	Month 11	3,347.8	2,116.9	225.6	4,388.3	1,005.4
Month 12	2,004.5	1,981.9	89.7	4,167.8	1,138.8	Month 12	2,310.0	2,397.6	86.8	4,958.5	1,209.1
tpy	**8.6**	**7.9**	**0.9**	**6.6**	**2.0**		**13.9**	**3.5**	**0.9**	**13.3**	**2.2**
2 Year Average	**6.3**	**7.1**	**0.7**	**11.2**	**2.5**		**10.0**	**6.0**	**0.8**	**12.0**	**2.4**
						UBC -Two 12 Months (Combined - tpy)	**16.3**	**13.1**	**1.5**	**23.3**	**4.9**

Annual outage - Routine
Major Maintenance
Maximum Month
Monthly values in Lbs
tpy = Tons per year

TABLE 4 Market Change Emissions UBC - Two 12 Month BAE Periods

	CO[1]	NOx[1]	SO2[1]	PM[3]	VOC[4]
Base Line Starts*	151	116	88	82	117
Projected Starts*	220	220	220	220	220
Increase Over Baseline*	69	105	132	138	104
Average Emissions Estimate (lb/Event)**	74.7	57.6	1.9	14.3	4.0
Emissions Over Baseline Starts lbs/yr*	5,171	6,024	246	1,967	413
Facility tpy	5.2	6.0	0.2	2.0	0.4

* Per Turbine

** Average of 2.03 hours per event blended Cold, Warm, Hot Start plus average shutdown.

(1) Based on startup CEMS data

(2) Based on high average lb/hr CEMS

(3) Based on fuel use and emissions rate determined by source testing normal operation w/DB On

(4) Based on fuel use and source testing emissions rates during BAE period.

tpy: tons per year

Table 5: Project Emissions Increase Summary

Project Emissions Increase Based on Two 12 Month BAE Periods						
		NOx	*CO*	*SOx*	*VOC*	*PM*
Total GT-1 & GT-2	*Projected Annual Emission in Tons*	***61.1***	***62.3***	***7.79***	***24.06***	**71.1**
	12 Month BAE	53.7	23.8	7.1	22.5	65.0
	Maximum Month UBC 1	13.1	16.3	1.5	4.9	23.3
	Starts UBC 2	6.0	5.2	0.2	0.4	2.0
	PEI=PAE-BAE-UBC1-UBC2	-5.7	22.2	-0.8	-3.4	-19.1
	NSR Threshold Tons	0.0	100.0	40.0	0.0	10.0
	Annual Permit Limits Tons	**155.7**	**254.0**	**12.1**	**43.8**	**134.8**

ATTACHMENT A

ALTERNATE BASELINE ACTUAL EMISSIONS (24-MONTH CONSECUTIVE PERIOD)

Attachment A - Alternate Baseine Actual Emissions - 24 Months

	Month, Year	UNIT 1						UNIT 2					
	Totals	CO	NOx	SO2	PM	VOC		CO	NOx	SO2	PM	VOC	Comments
	January	629.1	4,815.7	687.5	3,222.2	920.6		498.2	5,654.4	679.2	3,749.0	908.8	
	February	2.2	3.6	0.1	0.6	0.2		2.6	2.8	0.1	0.3	0.1	Maintenance on Steam Turbine Generator Rewind
	March	-	-	-	-	-		-	-	-	-	-	Maintenance on Steam Turbine Generator Rewind
	April	-	-	-	-	-		-	-	-	-	-	Maintenance on Steam Turbine Generator Rewind
	May	231.4	902.4	112.8	526.1	150.3		177.1	950.4	106.1	587.1	142.3	
2015	June	923.4	5,230.8	684.4	7,453.3	1,261.3		608.0	5,062.5	676.0	5,335.3	1,135.2	
	July	1,007.6	5,327.0	698.2	7,592.6	1,284.9		569.3	5,249.8	688.2	5,437.0	1,156.8	
	August	1,602.0	5,055.0	711.8	7,732.8	1,308.6		724.2	5,248.1	681.4	5,352.1	1,138.7	
	September	1,460.6	4,693.9	694.0	7,539.7	1,276.0		762.4	5,278.1	688.2	5,410.2	1,151.1	
	October	1,764.5	4,953.8	726.0	7,877.7	1,333.2		611.0	5,410.7	704.2	5,524.7	1,175.5	
	November	740.2	4,559.0	654.7	7,139.9	1,208.3		360.5	5,179.6	641.7	5,066.8	1,078.0	
	December	793.1	4,781.6	681.2	7,421.7	1,256.0		442.8	5,521.9	672.8	5,276.0	1,122.5	
	January	506.5	4,425.6	639.3	6,988.9	1,182.7		420.0	5,265.2	636.6	4,988.6	1,061.4	
	February	408.1	3,910.1	564.5	6,172.1	1,044.5		394.8	4,613.5	559.4	4,392.6	934.6	
	March	279.3	1,799.1	217.9	2,382.1	403.1		401.9	1,876.3	209.3	1,638.0	348.5	Annual outage - Routine
	April	509.5	3,678.4	499.9	5,433.0	919.4		579.6	3,979.2	475.4	3,735.0	794.7	
	May	522.5	4,199.5	579.5	6,330.6	1,071.3		537.6	4,536.3	557.9	4,391.6	934.4	
2016	June	895.8	4,576.5	669.3	2,566.8	111.6		783.0	5,100.2	655.6	7,453.6	109.6	
	July	1,128.7	4,952.6	733.6	2,821.6	122.7		1,096.0	5,596.8	730.3	8,283.9	121.8	
	August	1,231.7	5,441.7	759.3	2,928.2	127.3		1,645.8	5,799.5	755.3	8,593.9	126.4	
	September	1,047.2	4,842.3	714.1	2,754.8	119.8		1,027.6	5,431.7	708.8	8,045.7	118.3	
	October	1,200.8	5,053.9	744.9	2,862.3	124.4		1,632.5	5,654.5	737.3	8,371.3	123.1	
	November	828.4	4,480.8	654.2	2,526.0	109.8		1,256.3	4,589.5	577.0	6,558.1	96.4	
	December	1,066.6	4,263.7	581.6	2,243.0	97.5		1,442.8	4,644.7	560.0	6,381.0	93.8	
	January	968.8	4,950.7	613.9	2,360.6	102.6		1,430.9	4,957.6	591.4	6,745.2	99.2	
	February	906.0	2,199.8	226.4	870.5	37.8		1,199.0	2,130.6	200.7	2,274.5	33.4	
	March	1,143.9	2,508.6	229.3	894.1	38.9		1,069.3	2,449.0	198.8	2,253.4	33.1	
	April	1,145.9	2,464.6	219.9	849.8	36.9		870.7	2,239.3	186.1	2,108.0	31.0	HGP Maintenance - Burner Change Out
	May	1,222.0	3,719.0	439.2	1,690.2	73.5		153.8	140.2	5.7	64.4	0.9	HGP Maintenance - Burner Change Out
2017	June	1,067.9	4,470.0	554.7	7,635.5	1,955.4		525.7	4,766.3	520.4	4,879.3	1,742.6	
	July	1,563.3	4,940.4	725.0	9,948.5	2,547.8		1,251.4	5,961.9	715.9	6,679.9	2,385.7	
	August	1,665.7	4,753.8	701.4	9,614.1	2,462.2		1,193.2	5,855.4	701.5	6,551.5	2,339.8	
	September	1,302.0	4,265.1	601.9	8,279.1	2,120.2		1,226.8	5,310.0	612.3	5,729.6	2,046.3	
	October	1,647.2	4,835.8	707.9	9,697.2	2,483.4		1,006.0	5,785.7	694.2	6,493.1	2,319.0	
	November	1,595.1	4,649.8	683.5	9,362.1	2,397.6		752.8	5,582.1	672.9	6,296.3	2,248.7	
	December	1,622.5	4,843.0	692.6	9,509.7	2,435.4		964.2	5,943.6	673.7	6,301.3	2,250.5	
	January	304.5	623.0	75.0	1,026.6	262.9		966.5	3,098.5	316.9	2,954.5	1,055.2	Annual outage - Routine
	February	-	-	-	-	-		1,563.8	4,964.0	523.4	4,892.2	1,747.2	Major Maintenance On GT-1 Rotor
	March	939.5	1,699.5	162.3	2,245.6	575.1		1,341.1	5,643.0	623.9	5,833.8	2,083.5	Major Maintenance On GT-1 Rotor
	April	1,683.1	4,641.7	475.6	6,501.6	1,665.0		1,357.5	3,844.9	450.1	4,205.6	1,502.0	
	May	1,689.4	4,414.1	420.1	5,780.7	1,480.4		1,586.8	3,564.3	388.6	3,635.4	1,298.4	
2018	June	1,314.9	4,346.4	452.5	1,061.9	1,592.8		1,019.2	3,538.9	414.1	1,241.2	1,448.1	
	July	1,466.7	4,651.4	501.3	1,176.1	1,764.2		1,164.7	3,707.8	491.1	1,472.7	1,718.1	
	August	1,858.1	4,283.9	445.0	1,041.0	1,561.5		1,168.7	3,294.3	399.7	1,200.4	1,400.4	
	September	1,920.0	5,402.7	637.3	1,499.1	2,248.6		1,140.8	4,598.9	636.3	1,911.6	2,230.2	
	October	2,338.93	5,340.76	603.99	1,411.8	2,117.7		1,451.9	4,643.3	589.8	1,771.4	2,066.6	
	November	1,782.90	4,339.46	658.34	1,545.7	2,318.5		1,172.4	4,701.3	654.6	1,964.2	2,291.6	
	December	820.27	4,769.50	618.65	1,448.2	2,172.3		673.3	5,401.5	627.6	1,887.0	2,201.5	
	January	1,337.32	4,074.91	502.24	1,174.9	1,762.4		1,711.0	4,326.2	485.8	1,457.4	1,700.3	
	February	-	-	-	-	-		-	-	-	-	-	Major Maintenance on Steam Turbine Generator
2019	March	-	-	-	-	-		-	-	-	-	-	Major Maintenance on Steam Turbine Generator
	April	-	-	-	-	-		-	-	-	-	-	Major Maintenance on Steam Turbine Generator
	May	-	-	-	-	-		-	-	-	-	-	Major Maintenance on Steam Turbine Generator
	June	1,295.02	847.55	66.50	581.12	234.7		640.8	709.6	51.7	477.4	182.3	Major Maintenance on Steam Turbine Generator

Attachment A - Alternate Baseine Actual Emissions - 24 Months

	Month, Year	UNIT 1						UNIT 2					
	Totals	CO	NOx	SO2	PM	VOC		CO	NOx	SO2	PM	VOC	Comments
2019	July	1,901.84	5,589.02	648.14	6,709.18	2,272.5		1,497.8	4,525.1	629.5	5,778.2	2,206.2	
	August	2,416.37	6,150.09	707.51	7,372.43	2,497.1		1,929.5	5,721.4	696.5	6,423.4	2,452.6	
	September	2,456.35	5,759.28	662.73	6,857.71	2,322.8		1,618.6	3,685.7	547.3	5,019.3	1,916.5	
	October	2,713.92	5,704.03	617.60	6,400.08	2,167.8		2,251.1	4,737.9	658.7	6,038.6	2,305.7	
	November	2,777.82	6,396.06	745.38	7,732.94	2,619.2		1,883.2	5,700.0	692.7	6,368.7	2,431.7	
	December	2,588.71	5,894.58	720.11	7,455.89	2,525.4		2,008.7	4,983.1	716.5	6,567.1	2,507.4	
2020	January	2,220.6	5,275.0	665.2	5,773.5	2,331.6		2183.2	4434.4	660.8	6064.0	2315.3	
	February	2,576.7	5,050.0	570.6	4,989.9	2,015.1		1819.9	3743.5	577.6	5309.9	2027.4	
	March	1,162.5	2,815.5	306.5	2,660.8	1,074.6		905.8	1211.3	138.5	1267.7	484.0	Annual outage - Routine
	April	2,109.8	4,060.1	391.6	3,397.1	1,371.9		3029.9	3896.7	484.8	4471.2	1707.2	
	May	2,131.2	2,469.5	233.0	2,021.9	816.5		2170.5	1882.4	240.5	2206.2	842.4	
	June	3,341.8	5,191.8	544.7	5,626.3	1,814.9		3440.4	4327.5	529.7	4506.5	1767.2	
	July	3,053.9	5,630.7	669.6	6,952.2	2,242.6		3463.4	5688.3	668.5	5716.4	2241.7	
	August	3,215.1	4,894.0	539.2	5,604.5	1,807.9		3343.4	4260.9	517.1	4397.5	1724.5	
	September	2,384.5	4,975.6	585.1	6,061.4	1,955.3		3584.4	4648.0	663.9	5673.9	2225.0	
	Maximum Month Lbs	**2,338.9**	**5,441.7**	**759.3**	**9,948.5**	**2,547.8**		**1,711.0**	**5,799.5**	**755.3**	**8,593.9**	**2,385.7**	
	24 Month Period Lbs	**32,337.2**	**102,068.1**	**13,936.9**	**116,720.7**	**36,110.7**		**26,530.6**	**105,955.0**	**13,097.7**	**129,209.8**	**38,174.3**	
	Tons Per Unit	**16.2**	**51.0**	**7.0**	**58.4**	**18.1**		**13.3**	**53.0**	**6.5**	**64.6**	**19.1**	

Facility 1 Year Baseline Actual Emissions Based on 24 Month Period				
CO	**NOx**	**SO2**	**PM**	**VOC**
14.7	**52.0**	**6.8**	**61.5**	**18.6**

Notes:

1. Maximum month in 24-month period for each pollutant is shown in red text.
For example, the maximum month in 24-month period for Unit 1, CO pollutant is 3341.8 lbs (in October 2018).
2. Cells shaded in yellow show the 24-month period with maximum emissions for each pollutant.

General Steps:

1. 24-Month Period - Maximum Emissions Tables: The maximum emissions in 24-month period was determined for each pollutant.
2. 24-Month Period - The time period for the maximum emissions for each pollutant was identified and then used to determine the maximum emissions in the Actual Emissions tables.
3. Actual Emissions Tables: The maximum emissions in the Actual Emissions table were then inputted to the PAE table. Actual emissions were used for the outage month of February.

References:

District APR 1150 Policy: Implementation of Rule 2201 for SB288 Major Modification and Federal Major Modifications

ATTACHMENT B
ALTERNATE UNUSED BASELINE CAPACITY FROM MONTHLY OPERATIONS

Attachment B - Alternate Unused Baseline Capacity - 24 Month Period

	UNIT 1										
	CEMS			Emissions Factor from Source Testing 2019						Emissions Factor from Source Testing	
	CO	NOx	SO2	PM	VOC		CO	NOx	SO2	PM	VOC
Month 1	2,034.5	1,016.1	119.9	2,959.6	2,284.9	Month 1	744.5	534.3	118.6	3,605.3	1,330.5
Month 2	1,432.9	1,531.6	194.8	3,776.4	2,510.0	Month 2	512.0	1,186.0	195.9	4,201.3	2,352.3
Month 3	1,195.0	0.0	0.0	0.0	2,508.9	Month 3	641.7	0.0	0.0	0.0	2,352.6
Month 4	0.0	1,763.3	259.4	4,515.5	0.0	Month 4	0.0	1,820.3	279.9	4,858.9	0.0
Month 5	0.0	1,242.2	179.8	3,617.9	0.0	Month 5	0.0	1,263.2	197.4	4,202.3	0.0
Month 6	1,271.0	210.9	74.9	7,381.7	592.4	Month 6	1,185.3	737.0	79.3	1,140.3	643.1
Month 7	775.6	114.7	61.1	7,126.9	0.0	Month 7	459.6	549.7	67.0	310.0	0.0
Month 8	673.2	386.7	47.5	7,020.3	85.6	Month 8	517.8	551.4	73.9	0.0	45.9
Month 9	1,037.0	747.8	65.3	7,193.7	427.6	Month 9	484.2	521.4	67.1	548.2	339.4
Month 10	691.8	487.9	33.3	7,086.2	64.4	Month 10	705.0	388.8	51.1	222.6	66.7
Month 11	743.8	882.7	104.6	7,422.5	150.2	Month 11	958.2	620.0	113.6	2,035.8	137.0
Month 12	716.5	660.1	78.1	7,705.5	112.4	Month 12	746.8	277.6	82.5	2,212.9	135.2
tpy	**5.3**	**4.5**	**0.6**	**32.9**	**4.4**	**tpy**	**3.5**	**4.2**	**0.7**	**11.7**	**3.7**
Month 13	1,001.6	491.0	145.4	7,587.9	785.4	Month 13	0.0	841.9	163.9	1,848.7	685.4
Month 14	0.0	3,241.9	532.9	9,078.0	0.0	Month 14	147.2	3,668.9	554.6	6,319.4	638.5
Month 15	1,399.4	2,933.1	530.0	9,054.4	1,972.7	Month 15	369.9	3,350.5	556.5	6,340.5	302.2
Month 16	655.8	0.0	0.0	0.0	882.8	Month 16	353.5	0.0	0.0	0.0	883.7
Month 17	649.6	0.0	0.0	0.0	1,067.4	Month 17	124.2	0.0	0.0	0.0	1,087.3
Month 18	1,024.0	865.2	90.0	2,313.0	955.0	Month 18	691.8	699.3	99.7	3,714.6	937.6
Month 19	872.2	489.1	25.7	0.0	783.6	Month 19	546.3	202.7	25.0	1,914.0	667.6
Month 20	480.9	0.0	0.0	334.4	986.3	Month 20	542.3	0.0	0.0	2,042.4	985.3
Month 21	418.9	599.4	45.2	1,669.4	299.2	Month 21	570.2	367.8	46.4	2,864.3	155.5
Month 22	0.0	387.8	14.4	251.3	430.1	Month 22	259.1	145.0	18.0	2,100.8	319.1
Month 23	556.0	960.9	105.0	586.4	229.3	Month 23	538.6	1,210.0	178.3	2,297.6	94.1
Month 24	1,518.7	1,178.0	177.7	438.8	375.5	Month 24	1,037.7	1,154.8	195.3	2,292.6	184.2
tpy	**4.3**	**5.6**	**0.8**	**15.7**	**4.4**		**2.6**	**5.8**	**0.9**	**15.9**	**3.5**
2 Year Average tons	**4.8**	**5.0**	**0.7**	**24.3**	**4.4**		**3.0**	**5.0**	**0.8**	**13.8**	**3.6**
				UBC -24 Months (Combined - tpy)			**7.8**	**10.1**	**1.5**	**38.0**	**8.0**

Annual outage - Routine

Major Maintenance

Maximum Month

Monthly values in Lbs

tpy = Tons per year

ATTACHMENT C

ALTERNATVE UNUSED BASELINE CAPACITY FROM STARTUP EVENTS ABOVE BASELINE PERIOD

Attchment C - Alternate Market Change Emissions 24 Month Continuous BAE Period

	CO[1]	NOx[1]	SO2[1]	PM[3]	VOC[4]
Base Line Starts*	137	75	75	86	137
Projected Starts*	220	220	220	220	220
Increase Over Baseline*	83	145	145	134	83
Average Emissions Estimate (lb/Event)**	74.7	57.6	1.9	14.3	4.0
Emissions Over Baseline Starts lbs/yr*	6,198	8,359	270	1,914	331
Facility tpy	6.2	8.4	0.3	1.9	0.3

* Per Turbine

** Average event blended Cold, Warm, Hot Start plus average shutdown.

(1) Based on startup CEMS data

(2) Based on high average lb/hr CEMS

(3) Based on fuel use and emissions rate determined by source testing normal operation w/DB On

(4) Based on fuel use and source testing emissions rates during BAE period.

tpy: tons per year

ATTACHMENT D

ALTERNATIVE PROJECT EMISSIONS INCREASE BASED ON 24 MONTH BASELINE ACTUAL EMISSIONS

Attchment D - Alternate Market Change Emissions 24 Month Continuous BAE Period

			NOx	CO	SOx	VOC	PM
Total GT-1 & GT-2	***Projected Annual Emission in Tons***		***61.1***	***62.3***	***7.79***	***24.06***	***71.1***
	24 Month	***BAE***	52.0	14.7	6.8	18.6	61.5
	Maximum Month	***UBC 1***	10.1	7.9	1.5	8.0	38.0
	Starts	***UBC 2***	8.4	6.2	0.3	0.3	1.9
	PEI=PAE-BAE-UBC1-UBC2		-1.0	39.7	-0.5	-2.5	-28.4
	NSR Threshold Tons		0.0	100.0	40.0	0.0	10.0
	Annual Permit Limits Tons		**155.7**	**254.0**	**12.1**	**43.8**	**134.8**

All values in tons per year

UBC = Unused Baseline Capacity

APPENDIX D SJVAPCD NOTICE OF RECEIPT OF COMPLETE APPLICATION, MARCH 31, 2021

March 31, 2021

David King
Sunrise Power CO
12857 Sunrise Power Rd
Fellows, CA 93224

Re: Notice of Receipt of Complete Application
Facility Number: S-3746
Project Number: S-1204133

Dear Mr. King:

The San Joaquin Valley Air Pollution Control District (District) has received your Authority to Construct (ATC) application for increasing the rating of two gas turbine engine generators, at 12857 Sunrise Power Rd, Fellows. Based on our preliminary review, the application appears to be complete. This means that your application contains sufficient information to proceed with our analysis. However, during processing of your application, the District may request additional information to clarify, correct, or otherwise supplement, the information on file.

We will begin processing your application as soon as possible. In general, complete applications are processed on a first-come first-served basis.

It is estimated that the project analysis process will take 80.7 hours, and you will be charged at the weighted hourly labor rate in accordance with District Rule 3010. This estimate includes the following major processing steps: Determining Completeness (9.7 hours), Engineering Evaluation (35 hours), BACT Analysis (8 hours), Health Risk Assessment (13 hours), CEQA Analysis (5 hours) and Permit Preparation (10 hours). The current weighted labor rate is $107.00 per hour, but please note that this fee is revised annually to reflect actual costs and therefore may change. No payment is due at this time; an invoice will be sent to you upon completion of this project.

Please note that for projects subject to emission offsetting requirements, the following provisions apply:

- Pursuant to District Rule 2201, Section 7.5, the use of pre-baseline ERCs is prohibited if the usage of such credits during the effective period of a particular EPA-approved plan exceeds the respective pollutant's Pre-Baseline ERC Usage

Cap identified in that plan. Pre-baseline ERCs are those that were banked prior to the baseline year for a given EPA-approved Attainment Plan. Please note that this prohibition applies to ATC projects issued after the Pre-Baseline ERC Usage Cap is exceeded.

- The District offset equivalency system is not currently able to demonstrate equivalency with the surplus value test for NOx and VOC. Therefore, pursuant to Section 7.4.2.1 of District Rule 2201, all ATCs issued for new major sources or federal major modifications for NOx and VOC shall ensure that emission reductions used to satisfy District Rule 2201 offset requirements are creditable and that the surplus value of those credits must be determined at the time of ATC issuance.

Please also be aware that according to District Rule 2201, Section 5.3, *Final Action*, the District will not be able to issue the final ATC permit(s) until the requirements of the California Environmental Quality Act (CEQA) have been fully satisfied by the Lead Agency.

Please note that this letter is not a permit and does not authorize you to proceed with your project. Final approval, if appropriate, will be in the form of an ATC permit after application processing is complete. In addition, please be aware that because of the potential for litigation to be filed against the District by interested members of the public challenging the District's approval and issuance of a permit and/or any required CEQA documents, the District may require completion of an indemnification agreement and a letter of credit prior to the issuance of any permits.

If you have any questions, please contact Mr. Leonard Scandura at (661) 392-5500.

Sincerely,

Brian Clements
Director of Permit Services

Leonard Scandura

Leonard Scandura, P.E.
Permit Services Manager

BC:rcr