March 1, 2023
Permit No.: V-2152

IMPERIAL COUNTY AIR POLLUTION CONTROL DISTRICT

150 S. Ninth Street
El Centro, CA 92243
(442) 265 1800

MAJOR FACILITY PERMIT REVIEW

Company Name:	Imperial Irrigation District
Facility Name:	El Centro Generation Station
SIC Code:	4911 (Electric Services)
Source Type:	Power Plant
Mailing Address:	333 East Barioni Blvd, Imperial, CA 92251
Location:	485 East Villa Avenue, El Centro, CA 92243
Responsible Official:	Mr. Kraig Strauch
Plant Site Contact:	Mr. Hector Galarte
Permit Reviewer:	Jesus Ramirez

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I Introduction

Pursuant to Rule 900 of the Imperial County Air Pollution Control District (ICAPCD) Rules and Regulations, the ICAPCD intends to issue a Renewal Title V Operating Permit to Imperial Irrigation District (IID), El Centro Generating Station (ECGS). ECGS is an electrical generating facility (SIC 4911). Each electrical generating unit and auxiliary equipment operates under a different Authority to Construct/Permit to Operate number. The facility operates under Title V Operating Permit number V-2152. The Operating Permit includes conditions to ensure that all Federal requirements are satisfied.

II Project Description

The ECGS consists of one steam unit and two combined cycle unit. The net capacity for the entire facility is 333 MW. The combined cycle units produce electricity using the Brayton cycle and the Rankine cycle. The steam unit produces electricity using the Rankine cycle.

The IID operates also various auxiliary equipment for the production of electricity at the ECGS. This equipment includes three fuel oil storage tanks, one diesel fuel storage tank, one emergency power generator and one emergency fire pump.

The ECGS can operate under various operating modes. The proposed operating modes give the facility the flexibility to operate under the different conditions listed on the existing Authority to Construct and Permits to Operate.

III Emission Units and Control Devices Description

Following is a description of the principal emission units and control devices regulated by this permit:

Unit 2/Combined Cycle Unit

Unit 2 is a combined cycle unit with a net capacity of 115 MW. The construction of Unit 2 commenced on June 19, 1991. The combined cycle unit consists of a General Electric Frame 7EA combustion turbine with a rated capacity of 83 MW, an unfired heat recovery steam generator (HRSG), and related equipment. The HRSG produces steam to operate a steam turbine with a capacity of 32 MW. The combustion gas turbine has a maximum fuel input of 981.4 MMBtu/hr (all fuel values are based on higher heating value, HHV). The gas turbine burns natural gas as the primary fuel and No. 2 diesel fuel as the secondary fuel. Unit 2 employs steam injection and selective catalytic reduction (SCR) for the control of nitrogen oxides (NO_X). Cooling is provided by a

33,425 gpm cooling tower.

Unit 3/ Combined Cycle Unit

The Unit 3 Repower Project is comprised of two Siemens SGT-800 Combustion Turbine Generators (CTGs), two dual pressure duct fired heat recovery steam generators (HRSG) and one condensing steam turbine generator (STG). The Unit 3 Repower Project commenced its commercial operation in 2012. The rated capacity of nit 3 is 144 MW (net output at average ambient conditions). The CTGs are fired on pipeline pipe-line quality natural gas and are equipped with dry-low NOx (DLN) combustor technology. Both CTGs utilize ultra low NOx combustors and selective catalytic reduction (SCR) to control NOx emissions. The SCR relies upon injecting NH3 vapor in to the flue gasses, which then pass through a catalyst material to reduce NOx to elemental nitrogen and water. The HRSG incorporates a selective catalytic reduction system (SCR) and a carbon monoxide (CO) catalyst to control NOx and CO emissions. Cooling is provided by a 35,000 gpm cooling tower. The Unit 3 Project includes also one standby power generating unit driven by a 2206 bhp diesel engine and which is used for emergency ramp down events.

Unit 4/Steam Unit

Unit 4 is a conventional steam unit with a net capacity of 74 MW. Unit 4 commenced its commercial operation in 1968. This boiler was manufactured by Riley Stoker Corporation and is a wall-fired type with six Peabody burners (two rows of three). The boiler has a maximum fuel input of 829.8 MMBtu/hr. This boiler burns natural gas as the primary fuel and No. 6 fuel oil as the secondary fuel. Unit 4 was retrofitted with selective catalytic reduction (SCR) for the control of nitrogen oxides (NO_X) in 2000. Cooling is provided by a 41,000 gpm cooling tower.

IV Current Emission Status

The Imperial Irrigation District, ECGS, has submitted a Title V renewal application for its electrical generating facility at El Centro, California. This facility has been determined as a major source of emissions for Nitrogen Oxides (NO_X), Carbon Monoxide (CO), Sulfur Dioxide (SO_2), and Particulate Matter (PM-10). This facility is also an Acid Rain source subject to the requirements of Title IV of the Clean Air Act (CAA).

V Applicable Requirement

According to the information submitted in the Title V application and the District review, the following are the federal requirements that apply to the f
acility.

Applicable Requirement	Equipment Affected	Adoption Date
Rule 110-Stack Monitoring	Units 4	09/14/99
Rule 407-Nuisance	Facility Wide	09/14/99
Rule 201-Permits Required	Facility Wide	10/10/06
Rule 207-Standards for Permit to Construct	Facility Wide	09/11/18
Rule 208- Permit to Operate	Units 2, 3, 4, Emergency Fire Pump and Unconfined Sandblaster	09/14/99
Rule 400-Fuel Burning Equipment-Oxides of Nitrogen	Emergency Fire Pump and Unconfined Sandblaster	09/14/99
Rule 400.1-Stationary Gas Turbine(s)-Reasonable Available Control Technology (RACT)	Units 2, 3	02/23/10
Rule 400.2-Boilers, Process Heaters and Steam Generators	Unit 4	02/23/10
Rule 400.3-Internal Combustion Engines	Standby Power Generator and Emergency Fire Pump	10/22/13
Rule 401-Opacity of Emissions	Facility Wide	11/19/85
Rule 403-General Limitations on the Discharge of Air Contaminants	Units 2, 3, 4, Emergency Fire Pump and Unconfined Sandblaster	05/18/04
Rule 405-Sulfur Compounds Emission Standards, Limitations and Prohibitions	Units 2, 3, 4, Emergency Fire Pump and Unconfined Sandblaster	05/18/04
40 CFR Part 60, Subpart GG, Standards of Performance for Stationary Gas Turbines	Unit 2	
40 CFR Part 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines	Unit 3	
40 CFR Part 64, Compliance Assurance Monitoring	Unit 2, 3, 4	
40 CFR Parts 72, 73, 75, 77, 78-Acid Rain Program	Unit 2, 3, 4	

Permit to Operate # 2152C-4	Unit 2	
Permit to Operate # 3964A-3	Unit 3	
Permit to Operate # 1156A-2	Unit 4	
Permit to Operate # 2416B-3.	Sandblaster	
Authority to Construct # 2864A-2.	Emergency Fire Pump	
40 CFR Part 82, Stratospheric Ozone Protection	Air Conditioning Equipment	
Rule 900-Operating Permits	Facility Wide	12/20/11

VI Statements of Basis

The proposed Operating Permit includes conditions to ensure that all federal requirements will be satisfied. Additionally, the permit has been designed to have adequate monitoring, record keeping and reporting requirements to demonstrate continuous compliance with the permit conditions.

The following provides additional clarification regarding certain permit changes and permit conditions.

1. The original Permit to Operate for Unit 2 included only one steam turbine, 32 MW, run by one conventional boiler. An application was submitted by Imperial Irrigation District to re-power Unit 2. Unit 2 was re-powered by adding one 83 MW gas turbine to the process and auxiliary equipment, for a total capacity of 115 MW. The ATC permit #2152 was issued to Imperial Irrigation District on June 19, 1991, for a combined cycle unit. A Permit to Operate #2152 for the combined cycle unit was issued on March 3, 1994. The ICAPCD amended Permit to Operate #2152 to include new recordkeeping and monitoring conditions. The Permit to Operate number was change to 2152A.

   The permittee requested to modify Permit to Operate # 2152A, Condition C.1 regarding the emission limit of 0.24 lbs/hr of SO_2 when burning natural gas, to a Permit to Operate Condition which allows burning of natural gas with a total sulfur content of not more than 0.75 grains/100 standard cubic feet of natural gas. The Permit to Operate #2152A was amended following the District's NSR procedures. The SO_2 limit in Condition C.1 was extended from 0.24 lbs/hr to 2 lb/hr when burning natural gas. In addition, the sulfur content in the natural gas was limited to not more than 0.75 grains/100 standard cubic feet of natural gas. The source offset the increase on sulfur dioxide emissions to meet the new potential to emit for this emission unit. The Permit to Operate number was change to 2152B.

In 2005, the permittee requested to modify Permit to Operate # 2152B, Condition C.1 to include an exemption from the permitted nitrogen oxides and carbon monoxide (CO) emissions limits during start-ups. The start-up NOx emission limit was set at 80 lb/hr, 3-hour average, and CO emission limit at 100 lb/hr, 3-hour average. Start-up mode is defined as any time the gas turbine has been inactive or is restarting from a turbine trip. The Permit to Operate #2152B was amended following the District's NSR procedures. The Permit to Operate number was change to 2152C.

The permittee requested to modify Permit to Operate # 2152C to replace and modify operation of cooling tower and allow biodiesel as a permitted fuel for this unit. This unit has now the alternative to combust a combination consisting of 80% natural gas and 20% biodiesel. The emission limits for operation under fuel mix remain within current permit limits and corresponding to 100% natural gas combustion. The Unit 2 turbine retained its firing mechanisms and is able to run on natural gas and/or on a mix natural gas and biodiesel mixture (up to 80% natural gas and 20% biodiesel). The Permit to Operate #2152C was amended following the District's NSR procedures. The Permit to Operate number was change to 2152C-1.

On February of 2011, the permittee requested to modify Permit to Operate # 2152C-1 to modify the permit's secondary fuel source testing requirements to reflect the new requirements in Air District Rule 400.1, which would allow IID to source test secondary fuel every five (5) years. Further, the testing period could be extended if IID can prove Unit 2 did not fire secondary fuel during the timeframe in question. Permit to Operate # 2152C-1required to source test secondary fuel every three (3) years. The Permit to Operate #2152C-1 was amended following the District's NSR procedures. The Permit to Operate number was change to 2152C-2.

On May of 2011, the permittee requested to modify Permit to Operate # 2152C-2 to modify its permit in order to remove the co-firing requirements of biodiesel and natural gas, while concurrently including biodiesel as an additional secondary fuel. This modification allows this unit to burn biodiesel at a 100% rate instead of co-firing with natural gas, as it will now be used at Unit 2 as an additional secondary fuel. The Permit to Operate #2152C-2 was amended following the District's NSR procedures. The Permit to Operate #2152C-1 was amended following the District's NSR procedures. The Permit to Operate number was change to 2152C-3.

On October 6, 2015, the permittee requested to modify Permit to Operate #

2152C-3 to remove biodiesel as a permitted fuel from Conditions C.1 Table 1, C.6, D(3), D(4), D(5), D(8), and Equipment List (E) to disallow burning of biodiesel as a secondary fuel. These conditions were removed from the Permit to Operate as biodiesel is no longer burned at this unit. The Permit to Operate #2152C-3 was amended following the District's NSR procedures. The amended Permit to Operate #2152C-4 became federally enforceable; therefore, the Permit to Operate conditions will be incorporated into the Title V Operating Permit.

2. The original Permit to Operate # 1155A for Unit 3 included only one steam turbine, 44 MW, run by one conventional boiler. An application was submitted by Imperial Irrigation District to re-power Unit 3. The Authority to Construct Permit #3964, for repowering of Unit 3, was issued on February 16, 2010. The ATC was issued for Unit 3 Repower Project which includes two Siemens CTGs, two dual pressure duct fired heat recovery steam generators (HRSG) and one condensing steam turbine generator (STG) with a rated capacity of 144 MW.

   In 2012, the permittee requested to modify ATC Permit # 3964, to clarify the language in Condition B.5, which describes startup events and emissions. Clarification was provided based on permit application and start up emissions considered during the review of the original application. The ATC Permit # 3964 was amended following the District's NSR procedures. The ATC Permit number was change to 3964A.

   During the same year, the permittee requested a modification to ATC Permit # 3964A to include a standby power generating unit, run by a 2206 bhp diesel engine, which is used for emergency ramp down events. The ATC was issued on August 7, 2012. The ATC Permit #3964A was amended following the District's NSR procedures. The ATC Permit number was change to 3964A-1.

   Permit to Operate # 3964A-1, Condition B.7, of this permit pertaining to and/or referencing to commissioning period is no longer applicable to the operation of the turbines due to commissioning period has elapsed. In addition, Condition B.16 referencing surrender of cancelled Unit 3 previous Permit to Operate is not applicable since it refers to an outdated requirement. These requirements do not come from any Federal, State or SIP District regulation. These conditions were deleted from the Permit to Operate # 3964A-1 and are not included in the Title V Operating Permit. Additionally, Permit to Operate 3964A-1 was also revised to update conditions for operation of the 1500 KW emergency generator to meet the requirements of SIP Rule 400.3, Internal Combustion Engine(s).

   The Permit to Operate #3964A-2 is been amended following the District's NSR procedures. The ATC Permit number changed to 3964A-3. The Amended

Permit to Operate #3964A-3 became federally enforceable; therefore, the Permit to Operate conditions are incorporated into the Title V Operating Permit.

3. The original Permit to Operate #1156 for Unit 4 was issued on January 1, 1974. No conditions of Permit to Operate were issued for operation of Unit 4 at that time. The Permit to Operate was amended in 1991 to include conditions for operation of Unit 4.

   The Permit to Operate #1156 was amended to incorporate conditions to install and operate one selective non-catalytic reduction system (SNCR) for Unit 4. The SNCR system started operating around the middle of 2000. The SNCR was installed in order to assure compliance with the 140 lb/hr NOx limit of District's Rule 400. The amended Permit to Operate #1156A became federally enforceable; therefore, the Permit to Operate conditions are incorporated into the Title V Operating Permit.

   On May of 2011, the permittee requested to modify Permit to Operate # 1156A to modify the permit's secondary fuel source testing requirements to reflect the new requirements in Air District Rule 400.2, which regulates the emissions of nitrogen oxides (NOx) for boilers, process heaters, and steam generators. IID requested to allow source testing of secondary fuel every five (5) years. Further, the testing period could be extended if IID can prove Unit 4 did not fire secondary fuel during the timeframe in question. Permit to Operate # 1156A required to source test secondary fuel every three (3) years. The Permit to Operate #1156A was amended following the District's NSR procedures. The Permit to Operate number was change to 1156A-1.

   On June 2012, the permittee requested to modify Permit to Operate # 1156A-1 to demolish the wood cooling tower and replace it with a new three-cell, fire retardant fiberglass, counter-flow type cooling tower. The ATC was issued on June 13, 2012. The ATC Permit #1156A-1 was amended following the District's NSR procedures. The ATC Permit number was change to 1156A-2. The Amended Authority to Construct/Permit to Operate #1156-2 became federally enforceable; therefore, the Permit to Operate conditions are incorporated into the Title V Operating Permit.

4. Units 2 and 4 operate under various operating modes for the purpose of switching from burning natural gas to fuel oil. The operating modes are already permitted by the Authority to Construct or Permit to Operate for each unit; therefore, it is not necessary to include these alternative modes as alternative operating scenarios as the source requested in the Title V application. The various operating modes will be included in the Operating Permit as federally

enforceable conditions.

5. 40 CFR Part 60, Subpart GG, set limits for the operation of stationary gas turbines with a heat input at peak load equal or greater than 10 MMBtu/hr which were constructed, modified or reconstructed after 10/03/77. Combined-cycle Unit 2 was constructed in 1991, and this unit is above the 10 MMBtu/hr limit. Therefore, Unit 2 is subject to the requirements of Subpart GG.

6. Unit 2 is required to comply with 40 CFR Part 60, Subpart GG, for NO_X and SO_2 standards. The standard for NO_X for the stationary gas turbines will be calculated according to the guidelines in 40 CFR Part 60.332. Nitrogen oxide emissions will be calculated using the following equation:

   STD = 0.0075 * [14.4/Y] + F

   where:
   STD = allowable NO_X emissions (percent by volume at 15 percent oxygen on a dry basis).
   Y = manufacturers= rated heat rate at manufacturers= rated load (kilojules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak loads for the facility. The value of Y will not exceed 14.4 kilojoules per watt hour.
   F = NO_X emission allowance for fuel-bound nitrogen as defined in 60.332(a)(1).

   The following design and operational parameters were obtained from data submitted with the Authority to Construct application. The NO_X standards for operation of the stationary gas turbine for natural gas and No. 2 diesel fuel were calculated using the above equation. According to Subpart GG, these standards will be incorporated in the Title V permit conditions to regulate the NO_X emissions from the stationary gas turbines.

	Unit 2
	GE Frame 7EA
Rating (MW Gross)	83.0
Fuel Input, HHV (MMBtu/hr)	981.4
Fuel Input, HHV (Gigajoules/hr)	1,035.2
Heat Rate, HHV (Btu/KW-hr)	11,829.1
(Y) Heat Rate, (KJ/W-hr)	12.47
F Natural Gas (N2 = 2.2% by weight)	0.005
F No. 2 Fuel Oil (N2 = 0.015% by weight)	0.00

NOX - Natural Gas (% by volume at 15% O2)	0.014
NOX - No. 2 Fuel Oil (% by volume at 15% O2)	0.009

7. The requirements of 40 CFR Part 60, Subpart GG for NO_X will be subsumed under the NSR Permit to Operate #2152C-3 requirements. Unit 2 shall comply with the NO_X emission limit of 0.014% (15% O2, dry basis) or 140 ppmv when firing natural gas and 0.009% (15% O2, dry basis) or 90 ppmv when firing No. 2 diesel fuel. The NO_X emission limits for Unit 2 were set based on an emission level of 9 ppmv (15% O2, dry basis) when firing natural gas and 13 ppmv (15% O_2, dry basis) when firing No. 2 diesel fuel. These values are well below the Subpart GG limits. This is an appropriate action, due to the fact that the NSR permit requirements for nitrogen oxides are more stringent than the requirements of 40 CFR Part 60, Subpart GG. All of these requirements are currently federally enforceable; therefore, by streamlining these conditions we are not creating new federally enforceable requirements.

8. Unit 2 is subject to the requirements of 40 CFR Part 60.334, Monitoring of Operations, which requires monitoring of sulfur and nitrogen content of the fuel being fired in the turbine. The source will demonstrate compliance with these requirements through the following conditions:

   Monitoring of nitrogen content in pipeline natural gas will be waived since there is no fuel-bound nitrogen and since the free nitrogen does not contribute appreciably to NOx emissions, U.S.EPA memorandum of August 14, 1987, Authority for Approval of Custom Fuel Monitoring Schedules Under NSPS Subpart GG.

   NSPS fuel requirements for SOx will be satisfied by the exclusive use of natural gas fuel. A condition is included in the permits requiring the exclusive use of pipeline quality natural gas, which is limited in sulfur content to 20 grains or less per 100 standard cubic feet. By complying with this fuel standard, the Unit 2 will comply with the SO2 standards of Subpart GG.

   The gas turbine is limited to burn No. 2 diesel-fuel to a maximum of 720 hours in any calendar year. In reality, it is very unusual for Unit 2 to be fired on No. 2 diesel fuel. The testing and monitoring requirements contained in sections 60.334 and 60.335 will be subsumed under the testing and monitoring requirements established under the NSR permits and that is included on this Operating Permit. This will include the tri-annual emissions testing and the requirement to monitor operations with the use of CEMs.

9. Unit 2 is subject to the requirements of 40 CFR Part 60, Subpart GG, for SO_2.

The SO_2 limits of 40 CFR Part 60, Subpart GG will be subsumed under the NSR permit requirements. The SO_2 limit from Section 60.333(a) would be 150 ppmv. Compliance with this limit is assumed for Unit 2 due to the worst case limit contained in the NSR Permit of 2.0 lb/hr for natural gas. The SO_2 concentration at this permitted emission level would be 0.37 ppmv [2.0 lb SO_2/hr)*((MM lb moles air)/(64.1 lb-mol SO_2))*((379 ft^3 air)/(lb-mol air))/((542626 SDCFM *(60Min/hr))) = 0.37 ppmv].

This is an appropriate action, due to the fact that the NSR permit requirement for sulfur dioxide is more stringent than the requirements of 40 CFR Part 60, Subpart GG. This requirement is currently federally enforceable; therefore, by streamlining these conditions, we are not creating new federally enforceable requirements.

10. In accordance with 40 CFR Part 60.333(b), Unit 2 is restricted to burn liquid fuel with a sulfur concentration up to 0.8 percent by weight. Also, Unit 2 is limited to burn liquid fuel with a sulfur concentration up to 0.5 percent by weight per SIP Rule 405.B.5.b. The sulfur concentration in liquid fuel for Unit 2 will be subsumed under the NSR permit requirements. Compliance with these sulfur concentration limits is assumed due to the worst case limit contained in the NSR Permit to Operate #2152C-3, Condition C.4, of 0.05 percent by weight for No. 2 Diesel fuel.

    This is an appropriate action, due to the fact that the NSR permit requirement for sulfur concentration in liquid fuels is more stringent than the requirements of 40 CFR Part 60, Subpart GG, and SIP Rule 405. This requirement is currently federally enforceable; therefore, by streamlining these conditions, we are not creating new federally enforceable requirements.

11. In accordance with SIP Rule 405.B.1, Unit 2 is required to comply with a maximum limit of 0.2 percent by volume of sulfur compounds, calculated as sulfur dioxide. The SO_2 limit of SIP Rule 405.B.1 will be subsumed under the NSR permit requirements. The SO_2 limit of SIP Rule 405.B.1 would be 2000 ppmv. Compliance with this limit is assumed for Unit 2 due to the worst case limit contained in the NSR Permit to Operate #2152C-3, Condition C.1, of 2.0 lb/hr of SO_2 when the turbine is fueled on natural gas and 51 lb/hr of SO_2 for No. 2 Diesel fuel. The SO_2 concentration at the permitted emission level for No. 2 Diesel fuel would be 9.3 ppmv [51 lb SO_2/hr)*((MM lb moles air)/(64.1 lb-mol SO_2))*((379 ft^3 air)/(lb-mol air))/((542626 SDCFM *(60Min/hr))) = 9.3 ppmv].

    This is an appropriate action, due to the fact that the NSR permit requirements for sulfur dioxide are more stringent than the requirements of SIP Rule 405.B.1.

This requirement is currently federally enforceable; therefore, by streamlining these conditions, we are not creating new federally enforceable requirements.

12. In accordance with SIP Rule 400.1, Unit 2 is required to comply with a NOx limit of 42 ppmv (15% O2, dry basis) when operated on natural gas or 65 ppmv (15% O2, dry basis) when operated on liquid fuel.

    The requirements of SIP Rule 400.1 for NO_X will be subsumed under the NSR Permit to Operate #2152C-3 requirements. The NO_X emission limits for Unit 2 were set based on an emission level of 9 ppmv (15% O2, dry basis) when firing natural gas and 13 ppmv (15% O_2, dry basis) when firing No. 2 diesel fuel or biodiesel. These values are well below the SIP Rule 400.1 limits. This is an appropriate action, due to the fact that the NSR permit requirements for nitrogen oxides are more stringent than the requirements of SIP Rule 400.1. All of these requirements are currently federally enforceable; therefore, by streamlining these conditions we are not creating new federally enforceable requirements.

13. In accordance with SIP Rule 405.B.2.a.3, Unit 2 is required to comply with maximum limit of 200 lb/hr of sulfur compounds.

    The sulfur compounds limit of SIP Rule 405 will be subsumed under the requirements of NSR Permit to Operate # 2152C-3, Condition C.1. Compliance with these limits is assumed due to the worst case limits contained in the NSR Permit of 2 lbs/hr of sulfur dioxide when the unit is fired on natural gas and 51 lbs/hr of sulfur oxides when the unit is fired on No.2 Diesel fuel. This is an appropriate action, due to the fact that the NSR permit requirements for sulfur oxides emissions are more stringent than the requirements of SIP Rule 405. All of these requirements are currently federally enforceable; therefore, by streamlining these conditions, we are not creating new federally enforceable requirements.

14. 40 CFR Part 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines, set limits for the operation of stationary gas turbines with a heat input at peak load equal or greater than 10 MMBtu/hr which were constructed, modified or reconstructed after 02/18/05. Combined-cycle Unit 3 was constructed in 2012, and this unit is above the 10 MMBtu/hr limit. Therefore, Unit 3 is subject to the requirements of Subpart KKKK.

    Subpart KKKK limits NOx to 25 ppm (15% O2) and SO2 to 0.90 lb/MW-hr gross output or 0.060 lb/MMBtu/hr heat input. The controlled NOx, emissions from the Project's stationary natural gas turbines are less than or equal to 2.0 ppmvd at 15 percent 02, a level which is significantly below the applicable NSPS limit of 1.2

lb/MW-hr or 25 ppmv @ 15% O2. Therefore, Unit 3 is required to comply with this lower limit as the means of complying with the NOx limit of Subpart KKK. This is an appropriate action, due to the fact that the NSR permit requirements for nitrogen oxides are more stringent than the requirements of Subpart KKKK. All of these requirements are currently federally enforceable; therefore, by streamlining these conditions we are not creating new federally enforceable requirements.

NSPS fuel requirements for SOx will be satisfied by the exclusive use of natural gas fuel. A condition is included in the permits requiring the exclusive use of pipeline quality natural gas, which is limited in sulfur content to 20 grains or less per 100 standard cubic feet. By complying with this fuel standard, the Unit 3 will comply with the SO2 standards of Subpart KKKK.

15. NSR Permit to Operate # 3964A-3, Condition B.15, requires monitoring sulfur content in natural gas supplied to the turbines.

    The sulfur monitoring requirements of NSR Permit to Operate will be subsumed under the requirements of 40 CFR Part 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines, which requires also monitoring SO_2 emissions from Unit 3. Sulfur emissions will be monitored by implementing Custom Fuel Monitoring Schedules. Compliance with sulfur monitoring is assumed due to the sulfur monitoring requirement of NSR permit is identical to the monitoring requirements under Subpart KKKK. This is an appropriate action, due to the fact that the NSR permit requirements for monitoring sulfur content in the fuel are equivalent to the requirements of Subpart KKKK. All of these requirements are currently federally enforceable; therefore, by streamlining these conditions, we are not creating new federally enforceable requirements.

16. In accordance with SIP Rule 405.B.1, Unit 3 is required to comply with maximum limit of 0.2 percent by volume of sulfur compounds, calculated as sulfur dioxide. The SO_2 limit of SIP Rule 405.B.1 will be subsumed under the requirements of 40 CFR Part 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines, which requires to comply with an SO2 limit of 0.90 lb SO2 per MW-hour gross output. Since the power out of Unit 3 is 144 MW-hr then the SO2 limit of Subpart KKKK is 129.6 lb SO2/hour (144 MW/hr x 0.9 lb SO2/MW). The SO_2 limit of SIP Rule 405.B.1 would be 2000 ppmv. Compliance with this limit is assumed for Unit 3 due to the worst case limit contained in 40 CFR 60.4330(a)(1) of 129.6 lb SO2/hr. The SO_2 concentration from Unit 3, at the permitted emission level, for natural gas would be 44 ppmv [129.6 lb SO_2/hr)*((MM lb moles air)/(64.1 lb-mol SO_2))*((379 ft^3 air)/(lb-mol air))/((292,168 SDCFM *(60Min/hr))) = 44 ppmv].

This is an appropriate action, due to the fact that the NSR permit requirements for sulfur dioxide are more stringent than the requirements of SIP Rule 405.B.1. This requirement is currently federally enforceable; therefore, by streamlining these conditions, we are not creating new federally enforceable requirements.

17. 40 CFR Part 60, Subparts D, Da and Db set limits for the operation of steam generating units which were constructed or modified after 8/17/71 (Subpart D), 9/18/78 (Subpart Da), and 6/19/84 (Subpart Db).

    Unit 4 commenced its commercial operation in 1968. Unit 4 has not been modified since installation. However, in 2000, an SNCR system was installed to control NOx emissions from Unit 4. This project was implemented with the purpose of reducing NOx emissions from Unit 4. According to 40 CFR 60.2, Definitions, modification means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted. The installation of this SNCR system did not increase the amount of any air pollutant thus this project is not considered a modification. Therefore, the steam generating Unit 4 is not subject to Subparts D, Da and Db.

18. Unit 4 burn No. 6 fuel oil as a secondary fuel. U.S EPA has granted approval to Rule 405, Sulfur Compounds Emission Standards, Limitations and Prohibitions. Rule 405 limits sulfur maximum sulfur content in liquid fuels to maximum 0.5%. Therefore, Unit 4 is limited to burn No. 6 fuel oil with a sulfur concentration not to exceed 0.5 % by weight.

19. In accordance with SIP Rule 400.2, Section C.3, Unit 4 is required to comply with a NOx limit of 70 ppmv (15% O2, dry basis) when operated on natural gas or 70 ppmv (15% O2, dry basis) when operated on liquid fuel. Unit 4 is restricted to comply with an annual capacity factor of less than 30 percent.

    The nitrogen oxides limit of SIP Rule 400.2 will be subsumed under the requirements of NSR Permit to Operate # 1156A-2, Condition B.6. Compliance with these limits is assumed due to the nitrogen oxides limit of Rule 400.2 is identical to the limits contained in the NSR Permits of 70 ppmv of nitrogen oxides when the unit is fired on natural gas and 70 ppmv of nitrogen oxides when the unit is fired on fuel Oil. This is an appropriate action, due to the fact that the NSR permit requirements for nitrogen oxides emissions are equivalent to the requirements of SIP Rule 400.2. All of these requirements are currently federally enforceable; therefore, by streamlining these conditions, we are not creating new federally enforceable requirements.

20. In accordance with SIP Rule 405.B.1, Unit 4 are required to comply with maximum limit of 0.2 percent by volume of sulfur compounds, calculated as sulfur dioxide. The SO_2 limit of SIP Rule 405.B.1 will be subsumed under the requirements of NSR Permit to Operate # 1156A-2, Condition B.1. The SO_2 limit of SIP Rule 405.B.1 would be 2000 ppmv. Compliance with this limit is assumed for Unit 4 due to the worst case limit contained in the NSR Permit to Operate # 1156A-2, Condition B.1, of 200 lb/hr of SO_2 when the boilers are fueled on natural gas and 200 lb/hr of SO_2 for No. 6 diesel fuel. The SO_2 concentration from Unit 4, at the permitted emission level, for natural gas and fuel oil would be 195 ppmv [200 lb SO_2/hr)*((MM lb moles air)/(64.1 lb-mol SO_2))*((379 ft^3 air)/(lb-mol air))/((100808 SDCFM *(60Min/hr))) = 195 ppmv].

This is an appropriate action, due to the fact that the NSR permit requirements for sulfur dioxide are more stringent than the requirements of SIP Rule 405.B.1. This requirement is currently federally enforceable; therefore, by streamlining these conditions, we are not creating new federally enforceable requirements.

21. In accordance with SIP Rule 405.B.2, Unit 4 is required to comply with maximum limit of 200 lb/hr of sulfur compounds.

The sulfur compounds limit of SIP Rule 405.B.2 will be subsumed under the requirements of NSR Permit to Operate # 1156A-2, Condition B.1. Compliance with these limits is assumed due to the sulfur compounds limit of Rule 405.B.2 is identical to the limits contained in the NSR Permit of 200 lbs/hr of sulfur compounds when the unit is fired on natural gas and 200 lbs/hr of sulfur compounds when the unit is fired on fuel oil. This is an appropriate action, due to the fact that the NSR permit requirements for sulfur oxides emissions are equivalent to the requirements of SIP Rule 400.B. All of these requirements are currently federally enforceable; therefore, by streamlining these conditions, we are not creating new federally enforceable requirements.

22. In accordance with SIP Rule 405 the unconfined sandblaster and the emergency fire pump are required to comply with two different sulfur emission limits: a) 405.B.1 which sets a maximum limit of 0.2 percent by volume or 2000 ppmv of sulfur dioxide and b) 405.B.2. which sets a maximum limit of 200 lb/hr of sulfur compounds calculated as sulfur dioxide.

The sulfur compounds limit of SIP Rule 405.B.2 will be subsumed under the requirements of 405.B.1. Compliance with this limit is assumed for the unconfined sandblaster and the emergency fire pump due to the worst case limit contained in the 405.B.1 of 2000 ppmv of SO_2. The SO_2 concentration at 200 lb/hr would be 44997 ppmv for the unconfined sandblaster [200 lb SO_2/hr)*((MM lb moles air)/(64.1 lb-mol SO_2))*((379 ft^3 air)/(lb-mol air))/((438 SDCFM *(60Min/hr))) = 44997 ppmv]. The SO_2 concentration at 200 lb/hr would be 22784 ppmv for the emergency fire pump [200 lb SO_2/hr)*((MM lb moles air)/(64.1 lb-mol SO_2))*((379 ft^3 air)/(lb-mol air))/((865 SDCFM *(60Min/hr))) = 22784 ppmv]. This is an appropriate action, due to the fact that all these limits are above the 2000 ppmv requirement of 405.B.1. All of these requirements are currently federally enforceable; therefore, by streamlining these conditions, we are not creating new federally enforceable requirements.

23. In accordance with SIP Rule 403, the unconfined sandblaster and the emergency fire pump are required to comply with two different combustion contaminant limits: a) 403.B.3 which sets a maximum limit of 0.2 grains per dry cubic foot of gas, calculated at 12 percent carbon dioxide and b) 403.B.5 which sets a maximum limit of 10 lb/hr of combustion contaminants derived of fuel.

The combustion contaminants limit of SIP Rule 403.B.5 will be subsumed under the requirements of 403.B.3. Compliance with this limit is assumed for the unconfined sandblaster and the emergency fire pump due to the worst case limit contained in the 403.B.3. The combustion contaminants limit at 0.2 grains per dry cubic foot of gas would be 0.75 lb/hr for the unconfined sandblaster [(0.2 grains/dry cubic foot of gas)*(438 dry cubic foot/min)*(60Min/hr)*(1lb/7000 grains) = 0.75 lb/hr]. The combustion contaminants limit at 0.2 grains per dry cubic foot of gas would be 1.48 lb/hr for the emergency fire pump [(0.2 grains/dry cubic foot of gas)*(865 dry cubic foot/min)*(60Min/hr)*(1lb/7000 grains) = 1.48 lb/hr]. This is an appropriate action, due to the fact that all these limits are below the 10 lb/hr of combustion contaminants requirement of Rule 403.B.5. All of these requirements are currently federally enforceable; therefore, by streamlining these conditions, we are not creating new federally enforceable requirements.

24. Unit 2 - Compliance with requirements of 40 CFR Part 64, Compliance Assurance Monitoring. Due to the potential to emit for nitrogen oxide from Unit 2 is greater than 100 tons per year and this unit is subject to a NOx emission limit contained in the Authority to Construct Permit, Unit 2 is considered a large pollutant-specific emission unit for nitrogen oxides. This unit employs steam injection and selective catalytic reduction (SCR) for the control of nitrogen oxides (NO_X). 40 CFR Part 64 applies only to emission units which use a control device to achieve compliance with an emission limit; therefore, Unit 2 is subject to comply with the requirements of 40 CFR Part 64 for the nitrogen oxide emission limit. However, according to 40 CFR Part 64.2(b)(vi), the requirements of this

part are not applicable to any emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method.

The Authority to Construct Permit number 2152C-4, Condition D.1 requires install a continuous emission monitor (CEM) to measure NOx emissions from this turbine. This requirement is currently federally enforceable and it will be incorporated into the Title V Operating Permit for the facility. Therefore, Unit 2 is exempted from compliance with 40 CFR Part 64.

25. Unit 3 - Compliance with requirements of 40 CFR Part 64, Compliance Assurance Monitoring. Due to the potential to emit for nitrogen oxide from Unit 3 is greater than 100 tons per year and this unit is subject to a NOx emission limit contained in the Authority to Construct Permit, Unit 3 is considered a large pollutant-specific emission unit for nitrogen oxides. This unit employs dry low-NOx burners and selective catalytic reduction (SCR) for the control of nitrogen oxides (NO_X). 40 CFR Part 64 applies only to emission units which use a control device to achieve compliance with an emission limit; therefore, Unit 3 is subject to comply with the requirements of 40 CFR Part 64 for the nitrogen oxide emission limit. However, according to 40 CFR Part 64.2(b)(vi), the requirements of this part are not applicable to any emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method.

The Authority to Construct Permit number 3964A-3, Condition B.10 requires install a continuous emission monitor (CEM) to measure NOx emissions from this turbine. This requirement is currently federally enforceable and it will be incorporated into the Title V Operating Permit for the facility. Therefore, Unit 3 is exempted from compliance with 40 CFR Part 64.

26. Unit 4 - Compliance with requirements of 40 CFR Part 64, Compliance Assurance Monitoring. Due to the potential to emit for nitrogen oxide from Unit 4 is greater than 100 tons per year and this unit is subject to a NOx emission limit contained in the Authority to Construct Permit, Unit 4 is considered a large pollutant-specific emission unit for nitrogen oxides. This unit employs selective non-catalytic reduction (SNCR) for the control of nitrogen oxides (NO_X). 40 CFR Part 64 applies only to emission units which use a control device to achieve compliance with an emission limit; therefore, Unit 4 is subject to comply with the requirements of 40 CFR Part 64 for the nitrogen oxide emission limit. However, according to 40 CFR Part 64.2(b)(vi), the requirements of this part are not applicable to any emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method.

The Authority to Construct Permit number 1156A-2, Condition D.7 requires install a continuous emission monitor (CEM) to measure NOx emissions from this boiler. This requirement is currently federally enforceable and it will be incorporated into the Title V Operating Permit for the facility. Therefore, Unit 4 is exempted from compliance with 40 CFR Part 64.

27. The requirements within 40 CFR Part 63 Subpart YYYY, which establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, does not apply to El Centro Generating Station due to the fact that the facility is not classified as a major source of HAP emissions. The source does not emit or have the potential to emit any single HAP at a rate of 10 tons or more per year, or any combination of HAP at a rate of 25 tons or more per year.

28. The permittee operates several emission units and activities that are not included in the Title V permit due to the fact the air emissions from these units or activities are considered insignificant. These emissions units and activities are still required to comply with all federal requirements, as applicable. The Title V exclusion was granted following the guidance of CAPCOA Model List of Insignificant Activities for Title V Permit Programs, dated June 28, 2000. The emission units exempt, and the basis for their exemption, are listed in the Insignificant Activities Section which follows.

29. Title IV requirements have been added in accordance with Rule 901, Acid Deposition Control, of the Imperial County Air Pollution Control District and Titles IV and V of the Clean Air Act, the Imperial County Air Pollution Control District issues this permit pursuant to 40 CFR Part 72.

VII Insignificant Activities

The following types of activities and emission units will not be included in the Title V permit:

1. Solvent part cleaners: No. 1, 2, 3, and 4. The CAPCOA Model List of Insignificant Activities for Title V Permit Programs, dated June 28, 2000, excludes unheated nonconveyorized cleaning equipment with a surface area less than 2.0 sq.m., using organic solvents with an initial boiling point of 150EC or greater, and losing less than 25 gal/yr of solvent to the atmosphere. The solvent used at the cleaning station has an initial boiling point of 177EC, the area is smaller than 2 sq.m., and losses are less than 25 gal/yr.

2. Portable Propane Heaters. 0.02 MMBtu/hr propane fired heaters. Propane Heaters with a rating less than 5 MMBTU/hr will be excluded based on the

CAPCOA Model List of Insignificant Activities for Title V Permit Programs, dated June 28, 2000.

3. Diesel Storage Day Tank. Unheated diesel aboveground storage tank, 24,500 gal capacity, Diesel storage tanks will be excluded due to the low volatility of diesel, vapor pressure < 0.1 psia. Exclusion is based on the CAPCOA Model List of Insignificant Activities for Title V Permit Programs, dated June 28, 2000.

4. Residual Fuel Oil Day Tank. Unheated residual fuel oil aboveground storage tank, 37,800 gal capacity. Storage tank will be excluded due to the low volatility of residual fuel oil, vapor pressure <0.1 psia. Exclusion is based on the CAPCOA Model List of Insignificant Activities for Title V Permit Programs, dated June 28, 2000.

5. Residual Fuel Oil Tank (Tank No.5). Unheated residual fuel oil storage tank, aboveground storage tank, 44,760 bbl capacity. Residual fuel oil storage tank will be excluded due to the low volatility of residual fuel oil, vapor pressure < 0.1 psia. Exclusion is based on the CAPCOA Model List of Insignificant Activities for Title V Permit Programs, dated June 28, 2000.

6. Residual Fuel Oil Tank (Tank No.6). Unheated residual fuel oil storage tank, aboveground storage tank, 100,000 bbl capacity. Residual fuel oil storage tank will be excluded due to the low volatility of residual fuel oil, vapor pressure < 0.1 psia. Exclusion is based on the CAPCOA Model List of Insignificant Activities for Title V Permit Programs, dated June 28, 2000.

7. Diesel Storage Tank (Tank No. 7). Unheated diesel aboveground storage tank, 40,000 gal capacity, Diesel storage tanks will be excluded due to the low volatility of diesel, vapor pressure < 0.1 psia. Exclusion is based on the CAPCOA Model List of Insignificant Activities for Title V Permit Programs, dated June 28, 2000.

8. Bead Blaster. A glove-box type abrasive blast cabinet, vented to a dust-filter, with emissions to the atmosphere less than 2 pounds per day will be excluded based on the CAPCOA Model List of Insignificant Activities for Title V Permit Programs, dated June 28, 2000.

9. Miscellaneous Cleanup Solvents. The usage of solvents for repair and maintenance activities not related to the source=s primary business activities will be excluded based on the CAPCOA Model List of Insignificant Activities for Title V Permit Programs, dated June 28, 2000.

VIII Supplemental Annual Fee

The supplemental annual fee for the facilities will be determined according to the guidelines of Rule 900.G. The supplemental annual fee will be calculated according to the following equation:

s = [$ 58.55 per ton (CPI adjusted) x e] - f

where:

s =supplemental annual fee in dollars

e = fee-based emissions in tons per year

2021 Actual emission inventory for which fee-based emission schedule applies:

Nitrogen Oxides	=	86.7
Sulfur Dioxide	=	0.4
Particulate Matter (PM-10)	=	11.3
Volatile Organic Compounds	=	1.1
Total	=	99.5

f = sum (in dollars) of annual fees under Regulation III:

Equipment	Permit #	Fee Paid
Unit 2 Combined Cycle	2152C-4	$ 4,915.00
Unit 3 Steam Unit	3964A-3	$ 10,371.00
Unit 4 Steam Unit	1156A-2	$ 4,915.00
Sandblaster	2416B-3	$ 1,287.00
Emergency Fire Pump	2864A-2	$ 205.00
AB2588 Fee		$ 3,349.00
TOTAL		$ 25,042.00

Total Emissions of Fee Pollutants:	99.5 tons/yr
Emissions of Fee Pollutants x $ ***58.55***/ton:	$ 5,825.70
Annual Fees under Reg.III	$ 25,042.00
Estimated supplemental Title V Program Fee:	(5,825.70– 25,042.00) = (-)$ 19,216.30

These calculations indicate that the annual fee paid by the facility under Regulation III and AB2588 exceeds the emission fee pollutant schedule under Rule 900; therefore, no supplemental fee is required.