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EQUIPMENT LOCATION: 690 N. Studebaker Rd
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AUXILIARY BOILER & AUXILIARY BOILER SCR -- CONDITION CHANGES TO PERMITS TO CONSTRUCT

EQUIPMENT DESCRIPTION
SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

Note: *The applications submitted for the two Combined-Cycle Turbines, four Simple-Cycle Turbines, two SCR/CO Catalysts for the Combined-Cycle Turbines, and Storage Tank-1 (aqueous ammonia for combined-cycle turbines) (A/N 604015, 604018, 604020, 608431-608433, 610354-610360) (**"Application")** will be evaluated in a separate engineering evaluation.*

The applications for the Auxiliary Boiler and Auxiliary Boiler SCR (A/N 604014, 613323, and 604013) will be evaluated in this evaluation because the Auxiliary Boiler and SCR will be started up prior to the turbines.

*Applications were **not** submitted for the four SCR/CO Catalysts for the Simple-Cycle Turbines, Storage Tank-2 (aqueous ammonia for simple-cycle turbines), and two Oil/Water separators.*

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
PROCESS 12: INTERNAL COMBUSTION – POWER GENERATION					
SYSTEM 1: COMBINED-CYCLE TURBINES (AEC CCGT POWER BLOCK)					
BOILER, AUXILIARY, WATER-TUBE, NATURAL GAS, ~~BABCOCK & WILCOX~~ **CLEAVER-BROOKS**, MODEL ~~FM 103-88~~ **NB-200D-50**, WITH LOW NOX BURNER, FLUE GAS RECIRCULATION, 70.8 MMBTU/HR WITH	D181	C183		**CO**: 50 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002;	A63.4, A99.5, **A99.6**, A195.13, A195.14, C1.7, D29.5, ~~D29.6~~, D82.3,

A/N: ~~579158~~ **604014** BURNER, NATURAL GAS, ~~JZHC/COEN~~ **CB-NATCOM**, MODEL ~~RMB~~ **P-71-G23-11-16**, WITH LOW NOX BURNER, 70.8 MMBTU/HR	[B182]			RULE 1703(a)(2)-PSD-BACT, 10-7-1988]; CO: 400 PPMV NATURAL GAS (5) [RULE 1146, 11-1-2013**; RULE 1146, 12-7-2018**]; CO: 2000 PPMV NATURAL GAS (5A) [RULE 407, 4-2-1982]; **NOx:** 5 PPMV NATURAL GAS (4) [**RULE 1146, 11-1-2013; RULE 1146, 12-7-2018**; RULE 1703(a)(2) PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]; NOx: 38.46 LBS/MMSCF NATURAL GAS (1**A**) [RULE 2012, 5-6-2005]; **NOx: 104.20 LBS/MMSCF NATURAL GAS (1) [RULE 2012, 5-6-2005]** **PM10**: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; 0.0072 LB/MMBTU NATURAL GAS (4) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002] **VOC**: 0.0052 LB/MMBTU NATURAL GAS (4) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]	**D82.4,** E74.1, E193.4, E193.5, E193.10, H23.7, I297.7, K40.5
SELECTIVE CATALYTIC REDUCTION, AUXILIARY BOILER,	C183	D181 S211		**NH3**: 5 PPMV (4) [RULE 1303(a)(1)-	A195.16, D12.15,

BABCOCK & WILCOX, VANADIUM, 46 CU. FT.; WIDTH: 5 FT 5 IN; HEIGHT: 3 FT 8 IN; LENGTH: 7 FT 3 IN WITH A/N: ~~579166~~ **613323** AMMONIA INJECTION, AQUEOUS AMMONIA	[B184]			BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	D12.16, D12.17, ~~D29.4~~, **D29.7**, E74.1, E193.4, E193.5
STACK, AUXILIARY BOILER, HEIGHT: 80 FT; DIAMETER: 3 FT A/N: ~~579158~~ **604014**	S211	C183			

(1) Denotes RECLAIM emission factor
(2) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emissions limit
(5)(5A)(5B) Denotes command & control emission limit
(6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit
(8)(8A)(8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits
(10) See Section J for NESHAP/MACT requirements
** Refer to Section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

FACILITY CONDITIONS

F2.1 The operator shall limit emissions from this facility as follows:

Contaminant	Emissions Limit
PM2.5	Less than ~~100~~ **70** tons in any one year

The operator shall not operate any of the Boilers Nos. 1, 2, 3, 4, 5, 6 (Devices D39, D42, D45, D48, D51, D3, respectively), Combined-Cycle Turbines Nos. CCGT-1 and CCGT-2 **(**Devices D165 and D173, respectively), Auxiliary Boiler (Device D181), or Simple-Cycle Turbines Nos. SCGT-1, SCGT-2, SCGT-3, and SCGT-4 (Devices D185, D191, D197, and D203 respectively) unless compliance with the annual emission limit for PM2.5 is demonstrated.

Compliance with the annual emission limit shall be based on a 12-month rolling average basis. The operator shall calculate the PM2.5 emissions for the facility by summing the PM2.5 emissions for each of the sources by using the equation below.

Facility PM2.5, tons/year = (FF1*EF1 + FF2*EF2 + FF3*EF3 + FF4*EF4 + FF5*EF5 + FF6*EF6 + FF7*EF7 + FF8*EF8 + FF9*EF9 + FF10*EF10 + FF11*EF11+ FF12*EF12 + FF13*EF13)/2000

FF1 = Boiler No. 1 monthly fuel usage in mmscf; EF1 = 1.19 lb/mmscf
FF2 = Boiler No. 2 monthly fuel usage in mmscf; EF2 = 1.19 lb/mmscf
FF3 = Boiler No. 3 monthly fuel usage in mmscf; EF3 = 1.19 lb/mmscf

FF4 = Boiler No. 4 monthly fuel usage in mmscf; EF4 = 1.19 lb/mmscf
FF5 = Boiler No. 5 monthly fuel usage in mmscf; EF5 = 1.19 lb/mmscf
FF6 = Boiler No. 6 monthly fuel usage in mmscf; EF6 = 1.19 lb/mmscf

FF7 = Combined-Cycle Turbine No. CCGT-1 monthly fuel usage in mmscf; EF7 = 3.92 lb/mmscf
FF8 = Combined-Cycle Turbine No. CCGT-2 monthly fuel usage in mmscf; EF8 = 3.92 lb/mmscf

FF9 = Auxiliary Boiler monthly fuel usage in mmscf; EF9 = 7.42 lb/mmscf

FF10 = Simple-Cycle Turbine No. SCGT-1 monthly fuel usage in mmscf; EF10 = 7.44 lb/mmscf
FF11 = Simple-Cycle Turbine No. SCGT-2 monthly fuel usage in mmscf; EF11 = 7.44 lb/mmscf
FF12 = Simple-Cycle Turbine No. SCGT-3 monthly fuel usage in mmscf; EF12 = 7.44 lb/mmscf
FF13 = Simple-Cycle Turbine No. SCGT-4 monthly fuel usage in mmscf; EF13 = 7.44 lb/mmscf

Any changes to these emission factors must be approved in advance by the ~~SCAQMD~~ **South Coast AQMD** in writing and be based on unit specific source tests performed using ~~SCAQMD~~ **South Coast AQMD**-approved testing protocol.

AES Alamitos, LLC shall submit written reports of the monthly PM2.5 compliance demonstration required by this condition. The report submittal shall be included with the semi-annual Title V report as required under Rule 3004(a)(4)(f). Records of the monthly PM2.5 compliance demonstration shall be maintained on site for at least five years and made available upon ~~SCAQMD~~ **South Coast AQMD** request.

For the purpose of this condition, any one year shall be defined as a period of twelve (12) consecutive months determined on a rolling basis with a new 12-month period beginning on the first day of each calendar month.

[Rule 1325, ~~12-5-2014~~ **11-4-16; RULE 1325, 1-14-19**]

DEVICE CONDITIONS

AUXILIARY BOILER

A63.4 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
CO	Less than or equal to 605 LBS IN ANY CALENDAR MONTH
VOC	Less than or equal to 102 LBS IN ANY CALENDAR MONTH

PM10	Less than or equal to 113.5 LBS IN ANY CALENDAR MONTH
PM2.5	**Less than or equal to 113.5 LBS IN ANY CALENDAR MONTH**
SOx	Less than or equal to 32 LBS IN ANY CALENDAR MONTH

The boiler shall not commence with normal operation until the commissioning process has been completed. The South Coast AQMD shall be notified in writing once the commissioning process for the boiler is completed.

Normal operation may commence in the same calendar month as the completion of the commissioning process provided the boiler is in compliance with the above emission limits.

The operator shall calculate the monthly emissions for CO, VOC, PM10, **PM2.5**, and SOx using the equation below.

Monthly Emissions, lb/month = (Monthly fuel usage in mmscf/month) * (Emission factors indicated below)

The following emission factors shall be used to demonstrate compliance with the monthly emission limits.

For commissioning, the emission factors shall be as follows: CO, 107.16 lb/mmcf; VOC, 115.56 lb/mmcf; PM10/PM2.5, 7.42 lb/mmcf; and SOx, 2.08 lb/mmcf.

For ~~commissioning and~~ normal operation, the emission factors shall be as follows: ~~CO, 39.55 lb/mmcf;~~ VOC, 6.67 lb/mmcf; PM10**/PM2.5**, 7.42 lb/mmcf; and SOx, 2.08 lb/mmcf.

For normal operation, the CO emissions shall be measured with certified CO CEMS. For the interim period after commissioning but prior to CEMS certification, and in the event of CEMS failure subsequent to CEMS certification, the emission factor shall be CO, 39.55 lb/mmcf.

For a month during which both commissioning and normal operation take place, the monthly emissions shall be the sum of the commissioning emissions and the normal operation emissions.

The operator shall maintain records in a manner approved by the ~~District~~ **South Coast AQMD** to demonstrate compliance with this condition and the records shall be made

available to ~~District~~ **South Coast AQMD** personnel upon request. The records shall include, but not be limited to, natural gas usage in a calendar month.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

[Devices subject to this condition: D181]

A99.5 The 38.46 lbs/mmscf NOx emission limit(s) shall only apply during the interim period prior to CEMS certification to report RECLAIM emissions, not to exceed one year after start of unit operation.

The operator shall maintain records of natural gas usage for this period.

[RULE 2012, 5-6-2005]

[Devices subject to this condition: D181]

A99.6 The 104.20 lbs/mmscf NOx emission limit(s) shall only apply during the boiler commissioning period to report RECLAIM emissions, not to exceed one year after start of unit operations.

The operator shall maintain records of natural gas usage for this period.

[RULE 2012, 5-6-2005]

[Devices subject to this condition: D181]

A195.13 The 5**.0** PPMV NOx emission limit(s) is averaged over 1 hour, dry basis at 3 percent oxygen. This limit shall not apply to boiler commissioning and startup periods.

[RULE 1703(a)(2) - PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]

[Devices subject to this condition: D181]

A195.14 The 50**.0** PPMV CO emission limit(s) is averaged over 1 hour, dry basis at 3 percent oxygen. This limit shall not apply to boiler commissioning and startup periods.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

[Devices subject to this condition: D181]

C1.7 The operator shall limit the number of start-ups to no more than 10 in any one calendar month.

The number of cold startups shall not exceed 2 in any calendar month, the number of warm startups shall not exceed 4 in any calendar month, and the number of hot starts shall not exceed 4 in any calendar month, with no more than 1 startup in any one day.

The number of cold startups shall not exceed 24 in any calendar year, the number of warm startups shall not exceed 48 in any calendar year, and the number of hot startups shall not exceed 48 in any calendar year.

For the purposes of this condition, a cold startup is defined as a startup which occurs after the auxiliary boiler has been shut down for 48 hours or more. A cold startup shall not exceed 170 minutes. The NOx emissions from a cold startup shall not exceed 4.22 lbs.

For the purposes of this condition, a warm startup is defined as a startup which occurs after the auxiliary boiler has been shut down 10 hours or more but less than 48 hours. A warm startup shall not exceed 85 minutes. The NOx emissions from a warm startup shall not exceed 2.11 lbs.

For the purposes of this condition, a hot startup is defined as a startup which occurs after the auxiliary boiler has been shut down for less than 10 hours. A hot startup shall not exceed 25 minutes. The NOx emissions from a hot startup shall not exceed 0.62 lbs.

The operator shall maintain records in a manner approved by the ~~District~~ **South Coast AQMD**, to demonstrate compliance with this condition and the records shall be made available to ~~District~~ **South Coast AQMD** personnel upon request.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]

[Devices subject to this condition: D181]

D29.5 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NOx emissions	~~District~~ **South Coast AQMD** Method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	~~District~~ **South Coast AQMD** Method 100.1	1 hour	Outlet of the SCR serving this equipment
SOx emissions	**South Coast** AQMD Laboratory Method 307-91	~~District~~ **South Coast AQMD** Approved Averaging Time	Fuel Sample
VOC emissions	~~District~~ **South Coast AQMD** method 25.3	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	EPA Method 201A/ ~~District~~ **South Coast AQMD** Method 5.1	~~District~~ **South Coast AQMD** approved averaging time	Outlet of the SCR serving this equipment
PM 2.5	EPA Method 201A and 202	~~District~~ **South Coast AQMD** approved averaging time	Outlet of the SCR serving this equipment
NH3 emissions	~~District~~ **South Coast AQMD** Method 207.1 ~~and 5.3 or EPA method 17~~	1 hour	Outlet of the SCR serving this equipment

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

For each firing rate, the following operating data shall be included: (1) the exhaust flow rates, in actual cubic feet per minute (acfm), (2) the firing rates in Btu/hour, (3) the exhaust temperature, in degrees F, (4) the oxygen content of the exhaust gases, in percent, and (5) the fuel flow rate.

The test shall be conducted in accordance with a ~~District~~ **South Coast AQMD** approved source test protocol. The protocol shall be submitted to the ~~SCAQMD~~ **South Coast AQMD** engineer no later than 90 days before the proposed test date and shall be approved by the ~~District~~ **South Coast AQMD** before the test commences.

The test protocol shall include the identity of the testing lab, confirmation that the test lab is approved under the ~~District~~ **South Coast AQMD** Laboratory Approval Program for the required test method for the CO pollutant, a statement from the testing lab certifying that it meets the criteria of Rule 304 (no conflict of interest), and a description of all sampling and analytical procedures.

The sampling facilities shall comply with the ~~District~~ **South Coast AQMD** Guidelines for Construction of Sampling and Testing Facilities, pursuant to Rule 217.

The sampling time for the PM**10** and PM2.5 tests shall be 1 hour or longer as necessary to obtain a measureable amount of sample.

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

[RULE 1146, 11-1-2013; **RULE 1146, 12-7-2018;** RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]

[Devices subject to this condition: D181]

~~D29.6 The operator shall conduct source test(s) for the pollutant(s) identified below.~~

~~Pollutant(s) to be tested~~	~~Required Test Method(s)~~	~~Averaging Time~~	~~Test Location~~
~~CO emissions~~	~~District Method 100.1~~	~~1 hour~~	~~Outlet of the SCR serving this equipment~~

~~The test(s) shall be conducted in accordance with the testing frequency requirements specified in Rule 1146.~~

~~The test shall be conducted and the results submitted to the District within 60 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.~~

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

~~The test shall be conducted to demonstrate compliance with the Rule 1303 concentration and/or monthly emissions limit.~~

~~[Rule 1146, 11-1-2013; RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988]~~

~~[Devices subject to this condition: D181]~~

D82.3 The operator shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv

Concentrations shall be corrected to 3 percent oxygen on a dry basis.

The CEMS shall be installed and operating no later than 90 days after initial start-up of the auxiliary boiler, and in accordance with an approved ~~SCAQMD~~ **South Coast AQMD** REG XX CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from ~~SCAQMD~~ **South Coast AQMD**.

Rule 2012 provisional RATA testing shall be completed and submitted to the ~~SCAQMD~~ **South Coast AQMD** within 90 days of the conclusion of the boiler commissioning period. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3).

[RULE 1703(a)(2) - PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015; RULE 2012, 5-6-2005]

[Devices subject to this condition: D181]

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

CO concentration in ppmv.

Concentrations shall be corrected to 3 percent oxygen on a dry basis.

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

The CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine, and in accordance with an approved South Coast AQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from South Coast AQMD.

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

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

[Devices subject to this condition: D181 (auxiliary boiler)]

E74.1 Notwithstanding the requirements of Section E conditions, the Operator may commence the construction of Phase II of this project if all the following condition(s) are met:

The BACT/LAER determination for the Phase II of this project shall be reviewed and modified (by ~~SCAQMD~~ **South Coast AQMD**) as appropriate at the latest reasonable time which occurs no later than 18 months prior to the commencement of construction of Phase II of the project.

[40 CFR 52.21 – PSD, 6-19-1978]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle), D181 (auxiliary boiler), C169, C170, C177, C178 (combined-cycle control), C187, C188, C193, C194, C199, C200, C205, C206 (simple-cycle control), C183 (auxiliary boiler control), D163, D164 (ammonia tanks), D209, D210 (oil-water separators)]

E193.4 The operator shall upon completion of construction, operate and maintain this equipment according to the following requirements:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 13-AFC-01 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D163, D164, D165, D173, D185, D191, D197, D203, D181, C170, C178, C183, C188, C194, C200, C206, D209, D210]

E193.5 The operator shall install this equipment according to the following requirements:

The Permit to Construct shall expire one year from the issuance date, unless an extension has been granted by the Executive Officer or unless the equipment has been constructed and the operator has notified the Executive Officer prior to the operation of the equipment.

Construction of Phase 1 of the project (defined as the combined cycle turbines and associated control equipment, the auxiliary boiler and associated control equipment, storage tank D163, and oil water separator D209) shall commence within 18 months from the date of the Permit to Construct, unless an extension is granted by the Permitting Authority.

Construction of Phase 2 of the project (defined as the simple cycle turbines and associated control equipment, storage tank D164, and oil water separator D210) shall commence within 18 months of May 31, 2020 unless an extension is granted by the Permitting Authority.

Construction shall not be discontinued for a period of 18 months or more at any time during Phase 1 or Phase 2.

[RULE 205, 1-5-1990, 40 CFR 52.21 – PSD, 6-19-1978]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle), D181 (auxiliary boiler), C169, C170, C177, C178 (combined-cycle control), C187, C188, C193, C194, C199, C200, C205, C206 (simple-cycle control), C183 (auxiliary boiler control), D163, D164 (ammonia tanks), D209, D210 (oil-water separators)]

E193.10 The operator shall operate and maintain this equipment according to the following requirements:

The **total** commissioning period shall not exceed ~~30~~ **100** hours of fired operation for the auxiliary boiler from the date of initial boiler start-up.

The operator shall vent this equipment to the SCR control system whenever the auxiliary boiler is in operation after commissioning is completed.

The operator shall provide the ~~SCAQMD~~ **South Coast AQMD** with written notification of the initial startup date. The operator shall maintain records in a manner approved by the ~~District~~ **South Coast AQMD** to demonstrate compliance with this condition and the records shall be made available to ~~District~~ **South Coast AQMD** personnel upon request. The records shall include, but not be limited to, the number of commissioning hours and natural gas fuel usage.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]

[Devices subject to this condition: D181]

H23.7 This equipment is subject to the applicable requirements of the following Rules or Regulations:

Contaminant	Rule	Rule/Subpart
CO	~~District~~ **South Coast AQMD** Rule	1146
NOx	**South Coast AQMD Rule**	**1146**
NOx	**South Coast AQMD Rule**	**1100**

~~These requirement shall include applicable portable analyzer testing and source testing requirements.~~

[**RULE 1100, 12-7-18;** RULE 1146, 11-1-2013**; RULE 1146, 12-7-2018**]

[Devices subject to this condition: D181]

I297.7 This equipment shall not be operated unless the facility holds 1351 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]

[Devices subject to this condition: D181]

K40.5 The operator shall provide to the ~~District~~ **South Coast AQMD** a source test report in accordance with the following specifications:

Source test results shall be submitted to the ~~District~~ **South Coast AQMD** no later than 90 days after the source tests required by conditions D29.5, ~~D29.6,~~ and D29.4 are conducted.

Emission data shall be expressed in terms of concentration (ppmv), corrected to 3 percent oxygen (dry basis), mass rate (lbs/hr), lbs/MM cubic feet, and lbs/MMBtu. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.

All moisture concentration shall be expressed in terms of percent corrected to 3 percent oxygen.

Source test results shall also include, for each firing rate, the following operating data: (1) the exhaust flow rates, in actual cubic feet per minute (acfm), (2) the firing rates in Btu/hour, (3) the exhaust temperature, in degrees F, (4) the oxygen content of the exhaust gases, in percent, and (5) the fuel flow rate.

[RULE 1146, 11-1-2013; **RULE 1146, 12-7-2018;** RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1703(a)(2) - PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]

[Devices subject to this condition: D181]

SCR FOR AUXILIARY BOILER

A195.16 The 5.0 PPMV NH3 emission limit is averaged over 1 hour, dry basis at 3 percent oxygen.

The operator shall calculate and continuously record the NH3 slip concentration using the following equation:

NH_3 (ppmvd) = [a-b*(c*1.2)/1,000,000]*1,000,000/b, where:

a = NH3 injection rate (lb/hr)/17(lb/lb-mol)
b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol)
c = change in measured NOx across the SCR (ppmvd at 3% O2)

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to within plus or minus 5 percent calibrated at least once every 12 months. The operator shall use the method described above or another alternative method approved by the Executive Officer.

The ammonia slip calculation procedure shall be in effect no later than 90 days after initial startup of the boiler.

The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information without corroborative data using an approved reference method for the determination of ammonia.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: C183]

D12.15 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH3).

The operator shall also install and maintain a device to continuously record the parameter being measured. Continuously record shall be defined as measuring at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

The flow meter shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The operator shall maintain the ammonia injection rate between 0.3 and ~~1.1~~ **3.9** pounds per hour.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]

[Devices subject to this condition: C183]

D12.16 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the parameter being measured. Continuously record shall be defined as measuring at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

The temperature gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The exhaust temperature at the inlet of the SCR/CO catalyst shall be maintained between 415 degrees F and 628 degrees F, except during startups and shutdowns.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]

[Devices subject to this condition: C183]

D12.17 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.

The operator shall also install and maintain a device to continuously record the parameter being measured. Continuously record shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month.

The pressure gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The pressure differential shall not exceed 2.0 inches water column.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1703(a)(2)-PSD-BACT, 10-7-1988; ~~RULE 2005, 6-3-2011~~; RULE 2005, 12-4-2015]

[Devices subject to this condition: C183]

D29.4 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging. Time	Test Location
NH3 emissions	~~District~~ **South Coast AQMD** Method 207.1 ~~and 5.3 or EPA method 17~~	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted and the results submitted to the ~~District~~ **South Coast AQMD** within 60 days after the test date. The ~~SCAQMD~~ **South Coast AQMD** shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the certified CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable or not yet certified, a test shall be conducted to determine the NOx emissions using ~~District~~ **South Coast AQMD** Method 100.1 measured over a 60 minute averaging time period.

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

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: C170, C178 (combined-cycle), C188, C194, C200, C206 (simple-cycle), ~~C183 (auxiliary boiler)~~]

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

Pollutant(s) to be tested	Required Test Method(s)	Averaging. Time	Test Location
NH3 emissions	South Coast AQMD Method 207.1	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted and the results submitted to the South Coast AQMD within 60 days after the test date. The South Coast AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted quarterly to demonstrate compliance with the ammonia emission limit during the first 12 months of unit operation and thereafter, except that source tests may be conducted annually within 12 months thereafter when four consecutive quarterly source tests demonstrate compliance with the ammonia emission limit. If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the ammonia emissions limits prior to resuming annual source tests.

The NOx concentration, as determined by the certified CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable or not yet certified, a test shall be conducted to determine the NOx emissions using South Coast AQMD Method 100.1 measured over a 60 minute averaging time period.

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

[RULE 1146, 11-1-2013; RULE 1146, 12-7-2018; RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: C183 (auxiliary boiler)]

E74.1 Notwithstanding the requirements of Section E conditions, the Operator may commence the construction of Phase II of this project if all the following condition(s) are met:

The BACT/LAER determination for the Phase II of this project shall be reviewed and modified (by ~~SCAQMD~~ **South Coast AQMD**) as appropriate at the latest reasonable time

which occurs no later than 18 months prior to the commencement of construction of Phase II of the project.

[40 CFR 52.21 – PSD, 6-19-1978]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle), D181 (auxiliary boiler), C169, C170, C177, C178 (combined-cycle control), C187, C188, C193, C194, C199, C200, C205, C206 (simple-cycle control), C183 (auxiliary boiler control), D163, D164 (ammonia tanks), D209, D210 (oil-water separators)]

E193.4 The operator shall upon completion of construction, operate and maintain this equipment according to the following requirements:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 13-AFC-01 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D163, D164, D165, D173, D185, D191, D197, D203, D181, C170, C178, C183, C188, C194, C200, C206, D209, D210]

E193.5 The operator shall install this equipment according to the following requirements:

The Permit to Construct shall expire one year from the issuance date, unless an extension has been granted by the Executive Officer or unless the equipment has been constructed and the operator has notified the Executive Officer prior to the operation of the equipment.

Construction of Phase 1 of the project (defined as the combined cycle turbines and associated control equipment, the auxiliary boiler and associated control equipment, storage tank D163, and oil water separator D209) shall commence within 18 months from the date of the Permit to Construct, unless an extension is granted by the Permitting Authority.

Construction of Phase 2 of the project (defined as the simple cycle turbines and associated control equipment, storage tank D164, and oil water separator D210) shall commence within 18 months of May 31, 2020 unless an extension is granted by the Permitting Authority.

Construction shall not be discontinued for a period of 18 months or more at any time during Phase 1 or Phase 2.

[RULE 205, 1-5-1990, 40 CFR 52.21 – PSD, 6-19-1978]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle), D181 (auxiliary boiler), C169, C170, C177, C178 (combined-cycle control), C187, C188, C193, C194, C199, C200, C205, C206 (simple-cycle control), C183 (auxiliary boiler control), D163, D164 (ammonia tanks), D209, D210 (oil-water separators)]

BACKGROUND AND FACILITY DESCRIPTION

NOTE: This evaluation will follow the organization of the Final Determination Of Compliance (FDOC), issued on 11/18/16. The tables in this evaluation that were in the FDOC will have the same numbering as in the FDOC.

Existing Facility – Alamitos Generating Station

Southern California Edison (SCE) installed Utility Boiler No. 1 in 1956, No. 2 in 1957, No. 3 in 1961, No. 4 in 1962, No. 5 in 1969, and No. 6 in 1966. The AES Corporation purchased the power plant from SCE in 1998.

AES Alamitos, LLC (AES) (ID 115394), a wholly owned subsidiary of The AES Corporation (AES), operates the existing Alamitos Generating Station (AGS), which consists of six utility boilers (Units 1 - 6), six Selective Reduction Systems (SCRs), four aqueous ammonia tanks (29 wt. %), and Rule 219 exempt equipment.

A summary of the electric utility boiler generators are summarized in the table below.

Table 1 – Existing Utility Boilers

Application No. (Permit No.)	Equipment Description (Device No.)	Rating
A/N 408704 (F97795)	Boiler No. 1, Babcock and Wilcox, Natural Gas (D39)	1785 MMBtu/hr, 175 MW
A/N 408705 (F97796)	Boiler No. 2, Babcock and Wilcox, Natural Gas (D42)	1785 MMBtu/hr, 175 MW
A/N 408706 (F97797)	Boiler No. 3, Babcock and Wilcox, Natural Gas (D45)	3350 MMBtu/hr, 320 MW
A/N 408707 (F97798)	Boiler No. 4, Babcock and Wilcox, Natural Gas (D48)	3350 MMBtu/hr, 320 MW
A/N 408728 (F97901)	Boiler No. 5, Babcock and Wilcox, Natural Gas (D51)	4750 MMBtu/hr, 480 MW
A/N 408708 (F57292)	Boiler No. 6, Babcock and Wilcox, Natural Gas (D3)	4752.2 MMBtu/hr, 480 MW
Total Generating Capacity		**19,772.2 MMBtu/hr, 1950 MW**

The AGS facility is subject to Title V, Acid Rain, and RECLAIM (Cycle 1). The facility is in compliance with all federal, state, and local rules and regulations.

Alamitos Energy Center - Under Construction

- *Permitting History of Alamitos Energy Center*

  On 12/20/13, AES Southland, LLC (AES), a wholly owned subsidiary of The AES Corporation, submitted applications for Permits to Construct a combined-cycle gas turbine project, the Alamitos Energy Center (original AEC). On 12/27/13, AES submitted an *Application for Certification (AFC)* for the original AEC to the California Energy Commission (CEC). This repowering project was proposed to replace the six utility boilers (Units 1 - 6) at the AGS. The original AEC project was to consist of four 3-on-1 combined-cycle gas turbine power blocks, with twelve natural-gas-fired combustion turbine generators, twelve heat recovery steam generators, twelve SCR and CO oxidation catalyst systems, and four steam turbine generators; two aqueous ammonia tanks; and three oil/water separators. The AEC was to have a net generating capacity of 1936 MW and a gross generating capacity of 1995 MW. In November 2014, AES received notice from Southern California Edison (SCE) that it was shortlisted for a power purchase agreement (PPA). The power plant configuration selected by SCE for a PPA was different from the project configuration proposed for the original AEC. Consequently, on December 17, 2014, AES requested the South Coast AQMD to cancel the permit applications.

  On 10/23/15, AES Southland Energy, LLC (AES), a different wholly-owned subsidiary of The AES Corporation, submitted new applications for Permits to Construct an amended AEC in the configuration selected by SCE. On 10/26/15, AES submitted a *Supplemental Application for Certification (SAFC)* (13-AFC-01) for the amended AEC to the CEC. AES will construct, own, and operate the AEC, a natural-gas-fired, air-cooled, combined- and simple-cycle electrical generating facility with a gross generating capacity of 1094.702 megawatts (MW) and net generating capacity of 1072.67 MW. The proposed AEC will replace four existing electric utility boiler generator Units 1, 2, 3 and 6 with a new gas turbine generating system. The new generating system will consist of two natural gas-fired GE 7FA.05 combined-cycle gas turbine generators configured with a shared steam turbine generator and four natural gas-fired GE LMS100PB simple-cycle turbine generators. The combined generating capacity of the AEC will be 1094.7 megawatts (MW) (nominal) which replaces the generating capacity of the existing Unit 1 (175 MW), Unit 2 (175 MW), Unit 3 (320 MW), and Unit 6 (480 MW). The new AEC will be equipped with air pollution control equipment, which consists of catalysts (selective catalytic reduction and oxidation catalysts). Additional new proposed equipment will include an auxiliary boiler equipped with selective catalytic reduction, two aqueous ammonia storage tanks, and two oil/water separators.

  In February 2016, AES became aware that permit conditions will be included to limit annual emissions and cold start-ups on an annual and monthly basis. On 3/30/16, AES submitted revisions to the applications submitted on 10/23/15, primarily to increase the number of cold startups for the combined-cycle turbines on a monthly and annual basis. The revisions included revised emissions calculations and modeling, and incorporated revisions resulting from previous discussions with the South Coast AQMD over the course of permitting for the Huntington Beach Energy Project (HBEP) and AEC. The South Coast AQMD did not require new applications to be

submitted to replace the applications submitted on 10/23/15. On 4/12/16, AES submitted revised sections for Air Quality, Biological Resources, and Public Health Assessment to the CEC to update the *SAFC* submitted on 10/26/15.

The South Coast AQMD issued the Preliminary Determination of Compliance (PDOC) and proposed revised Title V permit for the AEC project on 6/30/16. The original noticing occurred on 6/30/16. The CEC made the Preliminary Staff Assessment (PSA) available on July 13, 2016. The South Coast AQMD renoticed the PDOC and proposed Title V permit on 11/10/16. The re-notice was to provide interested parties the opportunity to review the PDOC concurrently with the PSA. The South Coast AQMD issued the Final Determination of Compliance (FDOC) package, including the Draft Facility Permit for FDOC, on 11/18/16, based on the original noticing on 6/30/16. The FDOC included an "Addendum—Responses To Comments Received" which set forth the written comments submitted by (1) AES Alamitos on July 19, 2016 and (2) Helping Hand Tools (Rob Simpson) on August 9, 2016, and the South Coast AQMD responses to the comments.

CEC released the Final Staff Assessment (FSA) Part 2 (Air Quality/Greenhouse Gas Emissions and Public Health) on 12/8/16. On 12/2/16, a Title V hearing request submitted by Harvey Eder. On 12/20/16, the PDOC re-noticing public comment period ended. On 12/20/16, Bob Sarvey from Helping Hand Tools submitted a comment letter. On 1/13/17, South Coast AQMD sent a letter denying the Title V hearing to Harvey Eder. On 2/8/17, South Coast AQMD sent a response letter to Bob Sarvey. On 2/9/17, South Coast AQMD forwarded its response letter to Bob Sarvey's comment letter to the EPA for a 45-day review. (The South Coast AQMD response letter to Bob Sarvey's comment letter is not included in the "Addendum—Responses To Comments Received" in the FDOC, issued on 11/18/16. The FDOC was not revised as a result of Mr. Sarvey's comments.)

On 3/1/17, EPA provided early termination of review. On 3/27/17, the EPA 45-day review period would have ended absent the early termination. On 3/28/17, the public period (60 days) to petition EPA to object to the permit started, with an end date of 5/27/17.

The CEC issued the Presiding Member's Proposed Decision (PMPD) on 2/13/17. The CEC approved the *SAFC* for the amended AEC on 4/12/17 by adopting the Energy Commission Order, which in turn adopted the PMPD, Errata, and the Committee recommendations set forth therein for the *SAFC*. These adopted documents and recommendations comprise the Commission's Decision and were incorporated by reference into the Order. The Order was adopted, issued, effective, and final on 4/12/17.

- *Permits to Construct Issued*
  On 4/18/17, the South Coast AQMD issued the Permits to Construct for the following equipment for the Alamitos Energy Center.

Note: On 11/18/16, the South Coast AQMD issued the Final Determination of Compliance (FDOC) and the Draft Facility Permit for FDOC. Comments were received on the FDOC and Draft Facility Permit. The *FDOC Addendum--Permits To Construct Issuance*, dated 4/18/17, lists and describes the minor equipment description and permit condition changes made to the Draft Facility Permit for FDOC that were incorporated in the Permits to Construct.

Table 1A – Permits to Construct Issued

Application No.	Equipment Description
579140	RECLAIM/Title V Significant Revision
579142	GE 7FA.05 Combined-Cycle Gas Turbine Generator, Unit CCGT-1
579143	GE 7FA.05 Combined-Cycle Gas Turbine Generator, Unit CCGT-2
579145	GE LMS-100PB Simple-Cycle Gas Turbine Generator, Unit SCGT-1
579147	GE LMS-100PB Simple-Cycle Gas Turbine Generator, Unit SCGT-2
579150	GE LMS-100PB Simple-Cycle Gas Turbine Generator, Unit SCGT-3
579152	GE LMS-100PB Simple-Cycle Gas Turbine Generator, Unit SCGT-4
579158	Auxiliary Boiler
579160	Air Pollution Control Equipment, SCR/CO Catalyst for Turbine, Unit CCGT-1
579161	Air Pollution Control Equipment, SCR/CO Catalyst for Turbine, Unit CCGT-2
579162	Air Pollution Control Equipment, SCR/CO Catalyst for Turbine, Unit SCGT-1
579163	Air Pollution Control Equipment, SCR/CO Catalyst for Turbine, Unit SCGT-2
579164	Air Pollution Control Equipment, SCR/CO Catalyst for Turbine, Unit SCGT-3
579165	Air Pollution Control Equipment, SCR/CO Catalyst for Turbine, Unit SCGT-4
579166	Air Pollution Control Equipment, SCR for Auxiliary Boiler
579167	Aqueous Ammonia Storage Tank for Combined-Cycle Turbines
579168	Aqueous Ammonia Storage Tank for Simple-Cycle Turbines
579169	Oil/Water Separator for Combined-Cycle Turbines
579170	Oil/Water Separator for Simple-Cycle Turbines

- *Permits to Construct Extension*

  Because the AEC project is a multi-year, multi-phase project, condition E193.5 sets forth requirements for the extension of the expiration date for the Permits to Construct.

  On 4/17/18, the South Coast AQMD extended the expiration date of all Permits to Construct to 4/17/19. The South Coast AQMD's policy regarding multi-year projects is to grant a one-year permit to construct extension as long as the project proponent is meeting the increments of progress towards completing construction. AES had provided a permit extension request letter, dated 3/2/18, that indicated construction of the combined cycle units (Power Block 1, Phase 1) was initiated on August 7, 2017 and was currently on-going. Construction on Power Block 1 is expected to continue through to the 4th quarter of 2019. Construction of the simple cycle units (Power Block 2, Phase 2) is expected to begin in the third quarter of 2020. In addition, AES provided a major project milestones table. Based on the information provided, the South Coast AQMD extended the expiration date for all Permits to Construct for an additional year.

Since the construction of the combined-cycle units (Power Block 1, Phase 1) was initiated on 8/7/17, which is within one year of the date of issuance of the Permits to Construct on 4/18/17, condition E193.5 did not require the Permits to Construct for Phase 1 to be extended. AES requested the one-year extension as recommended by the South Coast AQMD.

On 4/12/19, the South Coast AQMD extended the expiration date of all Permits to Construct to 4/17/20. AES had provided a permit extension request letter, dated 3/15/19, that reiterated construction of the combined cycle gas turbine generators (Power Block 1) was initiated on August 7, 2017 and was currently on-going. As of March 15, 2019, all above ground structures and equipment have been erected and placed on foundations. Construction of Power Block 1 is approximately 70 percent completed and is expected to continue through to the 4th quarter of 2019 followed by commissioning of the combined cycle gas turbine generators. First fire of a combustion turbine is scheduled for October 3, 2019. Construction of the simple cycle gas turbine generators (Power Block 2) is expected to begin in the third quarter of 2020 after the combined cycle gas turbine generators have reached commercial operation. Construction of Power Block 2 cannot commence until construction and commissioning of Power Block 1 is complete and existing AES Alamitos generating station units 1, 2 and 6 have been permanently retired from service. The start of construction of Power Block 2 is constrained by the space on the site dedicated to Power Block 1 construction activity and interconnection capacity in the switchyard serving the site. Based on the information provided, the South Coast AQMD extended the expiration date an additional year.

- *Project Description*

  The Alamitos Energy Center (AEC), as permitted, will consist of two gas turbine power blocks.

  - **Power Block 1** will consist of one 2-on-1 combined-cycle gas turbine (CCGT) power block with two natural-gas-fired combustion turbine generators (CTGs), two unfired heat recovery steam generators (HRSGs), a steam turbine generator (STG), an air-cooled condenser. The CTGs are shown on the facility permit as No. CCGT-1 (D165) and No. CCGT-2 (D173). An auxiliary boiler (D181) equipped with an SCR (C183) provides enhanced startup times for the CTGs.

    For the purpose of the equipment description on the facility permit, the applicable operating scenario is the scenario that yields the highest Btu/hr consumption for the turbine. From *Table 15 - Combined-Cycle Turbine Operating Scenarios*, below, the applicable operating scenario is Case 1, based on 100% load, 28 ºF ambient temperature, and without inlet cooling. At those conditions, each combustion turbine generator is rated 236.645 MW-gross and 235.907 MW-net, at 28 ºF. The steam generator is rated 219.615 MW-gross and 208.965 MW-net, at 28 ºF.

    For the purposes of Rule 1304(a)(2) compliance demonstration and Rule 1304.1 fee calculation, the applicable operating scenario is the scenario that yields the maximum gross

output for the equipment (two combined-cycle turbines and the steam generator). The applicable operating scenario is Case 12, based on 100% load, 59 ºF. At those conditions, each combustion turbine generator is rated 231.197 MW-gross and 230.459 MW-net, at 59 ºF. The steam generator is rated 230.557 MW-gross and 215.402 MW-net, at 59 ºF.

Two selective catalytic reduction (SCR) systems (C170, C178) and CO oxidation catalysts (C169, C177) will be utilized for control of NOx and CO/VOC emissions, respectively. One 40,000-gallon ammonia (NH_3) storage tank (D163) will store 19% aqueous ammonia which is the reducing agent in the SCRs. An oil/water separator (D209) will be used to collect equipment wash water and rainfall. This power block is collectively the AEC CCGT and will be located on the southern-most portion of the AEC site.

- **Power Block 2** will consist of four simple-cycle gas turbines (SCGT) with intercoolers. The CTGs are shown on the facility permit as No. SCGT-1 (D185), No. SCGT-2 (D191), No. SCGT-3 (D197), and No. SCGT-4 (D203). For the purposes of the equipment description, Rule 1304(a)(2) compliance demonstration, and Rule 1304.1 fee calculation, the applicable scenario from *Table 31 - Simple-Cycle Turbine Operating Scenarios* is Case 12, based on 100% load, 59 ºF. At those conditions, each combustion turbine generator is rated 100.438 MW-gross and 99.087 MW-net, at 59 ºF. Four SCR/CO oxidation catalysts systems (C188/C187, C194/C193, C200/C199, C206/C205), a second 40,000-gallon aqueous ammonia tank (D164), and a second oil/water separator (D210) are included. This power block is collectively the AEC SCGT and will be located on the northern portion of the AEC site.

The AEC will meet the demand for new generation in the Los Angeles basin local electrical reliability area caused in large part by the closure of the San Onofre Nuclear Generating Station and anticipated retirement of older, natural-gas-fired generation currently using once-through ocean water cooling.

The California State Water Resources Control Board's *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* (OTC Policy) was adopted on 5/4/2010 and became effective on 10/1/2010. The Policy applies to existing power plants that currently have the ability to withdraw cooling water from the State's coastal and estuarine waters using a single-pass system, also known as once-through cooling (OTC). The existing Utility Boilers at AGS use once-through ocean water cooling. The repowering will bring the AGS into compliance by the current facility compliance date of December 31, 2020 by eliminating the use of ocean water for once-through cooling at the facility. The proposed combined-cycle combustion turbine generators will employ an air-cooled condenser for the steam turbine cycle heat rejection system, which receives exhaust water from the low-pressure section of the steam turbine and condense it to water for reuse. The proposed simple-cycle turbines will employ one air-cooled closed loop fluid cooler per two CTGs to reject waste heat from the intercooler and other gas turbine auxiliaries.

The technology for AEC will be configured and deployed as a multi-stage generating (MSG) asset designed to generate power across a wide range of capacity with relatively constant thermal efficiency and maximum operating flexibility. The project includes multiple generators, often termed "embedded generating units," whereby combinations of embedded generating units comprise the full operational capability for each power block, from minimum to maximum generating capacity. AEC will have the ability to generate power across a wide range of output from minimum turndown of a single AEC SCGT to maximum output of the entire project. The AEC CCGT, including the steam turbine generator, is designed to function in a 1-on-1 configuration at minimum load up to the maximum heat input of two combustion turbines and two HRSGs operating at 100 percent load.

AEC is being constructed on the brownfield site of the existing AGS, and located on an approximately 21-acre site within the larger 71.3-acre AGS parcel. The AGS parcel is bounded to the north by the SCE switchyard and State Route 22 (East 7th Street); to the east by the San Gabriel River and, beyond that, the Los Angeles Department of Water and Power Haynes Generating Station; to the south by the former Plains West Coast Terminals petroleum storage facility and undeveloped property; and to the west by the Los Cerritos channel, AGS cooling-water canals, and the residences west of the channel.

The demolition of the existing and operating Utility Boilers 1 – 6 is not necessary for the construction of AEC. These units will continue to provide essential electrical service concurrent with the construction of the AEC CCGT power block. Units 1, 2, and 6 will be retired once the AEC CCGT reaches the commissioning stage and becomes operational. Unit 3 will be retired once the AEC SCGT reaches the commissioning stage and becomes operational. Units 4 and 5 may operate through December 31, 2020, the current facility compliance date imposed by the OTC Policy.

The AEC facility will be federal Title V, Acid Rain, and RECLAIM facility (Cycle 1).

- *Modeling and Offset Exemption*

  South Coast AQMD Rule 1304(a)(2) provides a modeling and offset exemption for utility boiler repower projects. The exemption applies to: "The source is replacement of electric utility steam boiler(s) with combined cycle gas turbine(s), intercooled, chemically-recuperated gas turbines, other advanced gas turbine(s); solar, geothermal, or wind energy or other equipment, to the extent that such equipment will allow compliance with Rule 1135 or Regulation XX rules. The new equipment must have a maximum electrical power rating (in megawatts) that does not allow basinwide electricity generating capacity on a per-utility basis to increase. If there is an increase in basin-wide capacity, only the increased capacity must be offset." Offsets are provided from the South Coast AQMD internal offset accounts.

Rule 1304(a)(2) provides an exemption for the combined-cycle and simple-cycle turbines, but not the auxiliary boiler. This exemption is discussed in more detail under the rule analysis for Rule 1303(b)(1)—Modeling, below.

- *Proposed Schedule*
  The commissioning of the auxiliary boiler is scheduled to start on July 29, 2019, prior to the first fire of the first combined-cycle turbine on Oct 3, 2019.

- *New South Coast AQMD Applications Submitted*
  AES submitted four sets of applications in 2018 – 2019. The applications and fees are described in Table 4A (A/N 604013-604015, 604018, 604020), Table 4B (A/N 608431-608433), Table 4C (A/N 610354-610360), and Table 4D (A/N 613323) below.

  NOTE: A/N 604015, 604018, 604020, 608431-608433, 610354-610360 *("Application")* will be consolidated in a separate engineering evaluation.

  A/N 604014, 613323, and 604013 for the Auxiliary Boiler, Auxiliary Boiler SCR, and RECLAIM/Title V Revision, respectively, will be evaluated in this engineering evaluation. The auxiliary boiler and SCR will be started up prior to the turbines.

Table 4A – Administrative Applications

Application No.	Submittal Date	Deemed Complete Date	Equipment Description	Fees
604013	5/11/18	5/29/18	RECLAIM/Title V Revision	$2,247.02
604014	5/11/18	5/29/18	Auxiliary Boiler (A/N 579158)—**Converted to Change of Condition Application, Fee of $6,063.52.**	$920.48
604015	5/11/18	5/29/18	Combined-Cycle Turbine, CCGT-1 (A/N 579142)	$920.48
604018	5/11/18	5/29/18	Combined-Cycle Turbine, CCGT-2 (A/N 579143)	$920.48
604020	5/11/18	5/29/18	Aqueous Ammonia Tank-1 for Combined-Cycle Turbines (A/N 579167)	$920.48
			Total Fees	**$5,928.94**

Table 4B – Change of Condition Applications

Application No.	Submittal Date	Deemed Complete Date	Equipment Description	Fees
608431	11/9/18	1/9/19	SCR/CO Catalyst for Combined-Cycle Turbine, CCGT-1 (A/N 579160)	$2,763.20
608432	11/9/18	1/9/19	SCR/CO Catalyst for Combined-Cycle Turbine, CCGT-2 (A/N 579161)	$2,763.20 * 0.5 (identical) = $1,381.60
608433	11/9/18	1/9/19	RECLAIM/Title V Revision	$2,496.24
			Total Fees	**$6,641.04**

Table 4C – Modification Applications

Application No.	Submittal Date	Deemed Complete Date	Equipment Description	Fees
610354	2/8/19	5/23/19	Combined-Cycle Turbine (A/N 579142)	$19,779.97 * 1.5 (XPP) = $29,669.96
610355	2/8/19	5/23/19	Combined-Cycle Turbine (A/N 579143)	[$19,779.97 * 0.5 (identical)] * [1.5 (XPP)] = $14,834.99
610356	2/8/19	5/23/19	Simple-Cycle Turbine (A/N 579145)	$19,779.97 * 1.5 (XPP) = $29,669.96
610357	2/8/19	5/23/19	Simple-Cycle Turbine (A/N 579147)	[$19,779.97 * 0.5 (identical)] * [1.5 (XPP)] = $14,834.99
610358	2/8/19	5/23/19	Simple-Cycle Turbine (A/N 579150)	[$19,779.97 * 0.5 (identical)] * [1.5 (XPP)] = $14,834.99
610359	2/8/19	5/23/19	Simple-Cycle Turbine (579152)	[$19,779.97 * 0.5 (identical)] * [1.5 (XPP)] = $14,834.99
610360	2/8/19	5/23/19	RECLAIM/Title V Revision	$2,496.24
			Total Fees	**$121,176.12**

Table 4D – Change of Condition Application

Application No.	Submittal Date	Deemed Complete Date	Equipment Description	Fees
613323	6/6/19	6/12/19	SCR for Auxiliary Boiler (A/N 579166)	$2672.34
			Total Fee	**$2672.34**

On 5/15/19, Stephen O'Kane sent an e-mail detailing additional proposed changes resulting from a deep dive review of the permits with the operators. The South Coast AQMD response e-mails, dated 5/23/19 & 5/30/19, indicated that five of the six proposed changes can be incorporated into previously submitted pending applications but a new condition change application will be required for the Auxiliary Boiler SCR. A/N 613323 was submitted for the Auxiliary Boiler SCR on 6/6/19.

The table below summarizes (1) the proposed changes requested in the applications, and (2) the proposed changes requested in Stephen O'Kane's e-mail, dated 5/15/19.

Table 4E - Summary of Proposed Changes in Applications

Application No.	Equipment Description (Current Permit)	Proposed Changes
604013	RECLAIM/ Title V Revision	RECLAIM/TV Rev
604014	Auxiliary Boiler (A/N 579158, Device D181)	Administrative - Update manufacturer and model for the boiler and the burner to reflect equipment installed.

		Stephen O'Kane Email, 5/15/19 - Condition E193.10—Revise commissioning period from 30 hr to 100 hr. Appx. 6/12/19 – In a telephone conversation, Stephen O'Kane informed the South Coast AQMD that a CO CEMS would be installed on the auxiliary boiler at the Huntington Beach Energy Center. The process and equipment are the same at the AEC. **Administrative application converted to Change of Condition to incorporate the commissioning and CO CEMS revisions.**
604015	Combined-Cycle Turbine, CCGT-1 (A/N 579142, Devices D165, S172)	Administrative – Update stack height from 140 ft to 150 ft to reflect as-built conditions.
604018	Combined-Cycle Turbine, CCGT-2 (A/N 579143, Devices D173, S180)	Administrative – Update stack height from 140 ft to 150 ft to reflect as-built conditions.
604020	Aqueous Ammonia Tank-1 for Combined-Cycle Turbines (A/N 579167, Device D163)	Administrative – Update capacity and dimensions of tank to reflect equipment installed.
608431	SCR/CO Catalyst for Combined-Cycle Turbine, CCGT-1 (A/N 579160, Devices C170/C169)	Change of Condition – Revise condition D12.10 to update exhaust temperature range at inlet of SCR/CO catalyst from 570 – 692 deg F to 600 – 775 deg F. Stephen O'Kane Email, 5/15/19 – Revise condition D12.9 to update the ammonia injection rate range for SCR from 44 - 242 lb/hr to 20 – 242 lb/hr.
608432	SCR/CO Catalyst for Combined-Cycle Turbine, CCGT-2 (A/N 579161, Devices C178, C177)	Change of Condition – Revise condition D12.10 to update exhaust temperature range at inlet of SCR/CO catalyst from 570 – 692 deg F to 600 – 775 deg F. Stephen O'Kane Email, 5/15/19 – Revise condition D12.9 to update the ammonia injection rate range for SCR from 44 - 242 lb/hr to 20 – 242 lb/hr.
608433	RECLAIM/ Title V Revision	RECLAIM/TV Rev
610354	Combined-Cycle Turbine, CCGT-1 (A/N 579142, Devices D165, S172)	Modification – Increase annual operating hours by 1905 hours. Stephen O'Kane Email, 5/15/19 – Revise condition A63.2 from requiring the use of the CO emission factor to requiring the use of the CEMS readings after the CO CEMS certification to calculate compliance with the monthly and annual CO emissions limits.
610355	Combined-Cycle Turbine, CCGT-2 (A/N 579143, Devices D173, S180)	Modification – Increase annual operating hours by 1905 hours. Stephen O'Kane Email, 5/15/19 – Revise condition A63.2 from requiring the use of the CO emission factor to requiring the use of the CEMS readings after the CO CEMS certification to

		calculate compliance with the monthly and annual CO emissions limits.
610356	Simple-Cycle Turbine, SCGT-1 (A/N 579145, Devices D185, S190)	Modification – Reduce annual operating hours by 1300 hours. Stephen O'Kane Email, 5/15/19 – Revise condition A63.3 from requiring the use of the CO emission factor to requiring the use of the CEMS readings after the CO CEMS certification to calculate compliance with the monthly and annual CO emissions limits.
610357	Simple-Cycle Turbine, SCGT-2 (A/N 579147, Devices D191, S196)	Modification – Reduce annual operating hours by 1300 hours. Stephen O'Kane Email, 5/15/19 – Revise condition A63.3 from requiring the use of the CO emission factor to requiring the use of the CEMS readings after the CO CEMS certification to calculate compliance with the monthly and annual CO emissions limits.
610358	Simple-Cycle Turbine, SCGT-3 (A/N 579150, Devices D197, S202)	Modification – Reduce annual operating hours by 1300 hours. Stephen O'Kane Email, 5/15/19 – Revise condition A63.3 from requiring the use of the CO emission factor to requiring the use of the CEMS readings after the CO CEMS certification to calculate compliance with the monthly and annual CO emissions limits.
610359	Simple-Cycle Turbine, SCGT-4 (A/N 579152, Devices D203, S208)	Modification – Reduce annual operating hours by 1300 hours. Stephen O'Kane Email, 5/15/19 – Revise condition A63.3 from requiring the use of the CO emission factor to requiring the use of the CEMS readings after the CO CEMS certification to calculate compliance with the monthly and annual CO emissions limits.
610360	RECLAIM/ Title V Revision— All applications except A/N 604014, 613323, and 604013.	RECLAIM/TV Rev—Consolidate all facility permit condition changes. From A/N 604013--Revise facility condition F52.1 to update the permanent shutdown date for Boilers No. 1, 2, and 6 from December 29, 2019 to January 2, 2020. Stephen O'Kane Email, 5/15/19 – Revise facility condition F52.2 to clarify the requirements for the circuit breakers at the facility utilizing SF6 refers to the new AEC facility with the turbines, not the existing AGS facility with the utility boilers. **Note:** The auxiliary boiler will be included in the facility-wide modeling and health risk assessment for the Application (A/N 604015, 604018, 604020, 608431-608433, 610354-610360) in support of the CEC's analysis of the *Petition for Post-Certification Amendment*.

613323	SCR for Auxiliary Boiler (A/N 579166, Device C183)	Stephen O'Kane Email, 5/15/19 – Revise condition D12.15 to update the ammonia injection rate to the SCR from 0.3 – 1.1 lb/hr to 0.3 – 3.9 lb/hr.

AES PROPOSED CHANGES TO EQUIPMENT DESCRIPTIONS AND PERMIT CONDITIONS

Note: *A/N 604014 is the master file.*

1. A/N 604014 - Auxiliary Boiler (A/N 579158)

(A) The application was initially submitted as an administrative application because it proposed to only update the manufacturer and model for the boiler and the burner to reflect the boiler purchased and installed. The application initially stated that no changes to the boiler rating, emission guarantees, emission limits, stack, monitoring parameters, fuel usage, or operating schedule were requested.

The proposed changes to the equipment descriptions for the boiler and burner are:

BOILER, AUXILIARY, WATER-TUBE, NATURAL GAS, ~~BABCOCK & WILCOX~~ **CLEAVER-BROOKS**, MODEL ~~FM 103-88~~ **NB-200D-50**, WITH LOW NOX BURNER, FLUE GAS RECIRCULATION, 70.8 MMBTU/HR WITH

BURNER, NATURAL GAS, ~~JZHC/COEN~~ **CB-NATCOM**, MODEL ~~RMB~~ **P-71-G23-11-16**, WITH LOW NOX BURNER, 70.8 MMBTU/HR

The application included a Cleaver-Brooks proposal, dated 3/9/18, from Aaron Fink, VP of National Sales, Cleaver Brooks Inc. – Engineering Boiler Systems Division, that provided the following guarantees and data:

- Boiler Type: Water-tube
  Comparison: Same as FDOC.
- Maximum heat input: 70.8 MMBtu/hr
  Comparison: Same as FDOC.
- Boiler NOx Control: FGR and Low NOx Burner
  Comparison: Same as FDOC.
- NOx at Boiler Outlet (ppmv at 3% O2, 1-hr average): 30
  Comparison: Uncontrolled emission rate were not provided for FDOC. Emissions calculations were based on the controlled emission rate.
- Ammonia Slip (ppmvd at 3% O2, 1-hr average): 5

Comparison: Same as FDOC.

- Guaranteed Emission Rates
  - NOx at SCR Outlet (ppmv at 3% O2, 1-hr average): 5
    Comparison: Same as FDOC.

  - CO (ppmv at 3% O2, 1-hr average): 50
    Comparison: Same as FDOC.

  - VOC (lb/MMBtu HHV): 0.004
    Comparison: FDOC was based on 0.0052 lb/MMBtu, the default Annual Emissions Reporting (AER) emission factor, which is more conservative than the 0.004 lb/MMBtu provided by Cleaver-Brooks. The emission rate will not be revised to the lower rate.

  - PM10 (lb/MMBtu HHV): 0.007
  - PM2.5 (lb/MMBtu HHV): 0.007
    Comparison: FDOC was based on 0.0072 lb/MMBtu, the default AER emission factor, which is more conservative than the 0.007 lb/MMBtu provided by Cleaver-Brooks. The emission rate will not be revised to the lower rate.

- Stack Height (feet above grade): 80
  Comparison: Same as FDOC.

- Stack Inside Diameter (feet): 3
  Comparison: Same as FDOC.

As the Cleaver-Brooks proposal confirms the boiler rating, stack dimensions, and guaranteed controlled NOx and CO emission rates are the same as for the FDOC, the equipment description will be revised as proposed.

(B) Stephen O'Kane's email, dated 5/15/19, provided an additional change to the auxiliary boiler.
For the FDOC, condition E193.10 limited the commissioning period to 30 hours. The commissioning duration is required to be limited because condition A195.13 and A195.14 exempts the NOx and CO BACT limits during commissioning. The duration limit constitutes alternative BACT.

Mr. O'Kane's email indicated the condition E193.10 commissioning period is required to be revised from 30 hr to 100 hr. As this revision required evaluation of commissioning

emissions and emission factors but did not result in an increase of emissions, this application was converted to a change of condition application.

(C) In a telephone conversation on approximately 6/12/19, Stephen O'Kane informed the South Coast AQMD that a CO CEMS would be installed on the auxiliary boiler at the Huntington Beach Energy Center. The process and equipment are the same at the AEC.

The following changes will be made as a result of the addition of the CO CEMS.

(i) Condition A63.4 sets forth the monthly emission limits for CO, VOC, PM_{10}, $PM_{2.5}$, and SOx. The condition currently requires the use of the provided CO emission factor to calculate CO emissions for normal operation. The condition will be revised to require the use of the CO CEMS to measure CO emissions.

(ii) Add condition D82.4 to specify requirements for the CO CEMs for the auxiliary boiler.

(iii) *Rule 1146—Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, amended 12/7/18*

(aa) The analysis for paragraph (d)(9) regarding portable analyzer testing and source testing has been revised to account for the CO CEMS.

(bb) Condition D29.6--Condition D29.6 requiring periodic source testing for CO will be deleted because subparagraph (d)(7)(A) allows periodic source testing **or** continuous emissions monitoring verification such as RATA tests for the CO CEMS.

(cc) Condition K40.5—The reference to condition D29.6 will be removed because that condition will be deleted.

(dd) Condition H23.7-- Condition H23.7 currently requires CO to meet the applicable requirements of Rule 1146. The condition also states: "These requirement shall include applicable portable analyzer testing and source testing requirements." In accordance with the requirements of paragraph (d)(9) discussed above, the condition will be updated, as a result of the installation of the CO CEMS, to remove the condition that the requirements shall include applicable portable analyzer testing and source testing requirements.

Also, condition H23.7 will be revised to require compliance with the applicable requirements of Rules 1146 and 1100 for NOx.

(iv) The *Rule 218 – Continuous Emission Monitoring* analysis has been revised to discuss the auxiliary boiler CO CEMS certification.

2. A/N 613323 - Auxiliary Boiler SCR (A/N 579166)
Stephen O'Kane's email, dated 5/15/19, indicated that condition D12.15 ammonia injection rate is required to be revised: "The operator shall maintain the ammonia injection rate between 0.3 and ~~1.1~~ **3.9** pounds per hour." In an email dated 5/31/19, Mr. O'Kane explained that the Cleaver Brooks boiler had the same heat input, steam production, emission guarantees and stack characteristics as the original vendor, Babcock & Wilcox, but the recommended ammonia flow rates for all conditions will be between 0.3 and 3.9 lb/hr.

3. 604013 - RECLAIM/ Title V Revision
This RECLAIM/Title V revision application was originally submitted for (1) A/N 604014, Auxiliary Boiler; (2) A/N 604015, Combined-Cycle Turbine CCGT-1; (3) A/N 604018, Combined-Cycle Turbine CCGT-2; and (4) A/N 604020, Aqueous Ammonia Tank for Combined-Cycle Turbines.

Because the auxiliary boiler commissioning will take place before the commissioning for the turbines, A/N 604013 will be the RECLAIM/Title V revision application for A/N 604014 and 613323.

All other applications ("Application") will be consolidated in a separate engineering evaluation. A/N 610360 will be the RECLAIM/Title V revision application for these other applications.

A/N 604013 also proposes to revise facility condition F52.1 to update the permanent shutdown date for Boilers No. 1, 2, and 6 from December 29, 2019 to January 2, 2020. However, all proposed facility condition changes will be consolidated and evaluated in the separate evaluation for the Application (A/N 604015, 604018, 604020**,** 608431-608433**,** 610354-610360), with A/N 610360 as the RECLAIM/Title V revision application.

SOUTH COAST AQMD CONDITION UPDATES

1. Pursuant to current agency requirements, references to "SCAQMD," "District" or "AQMD" in the existing conditions will be updated to "South Coast AQMD" in the engineering evaluation. Depending on how the condition is programmed in the facility permit program, the engineer may not be able to make some of the updates in the facility permit program until the facility permit program is re-programmed in the future. (Remaining references to "SCAQMD," "District" or "AQMD" in the facility permit that have not been updated in conjunction with the evaluation of applications will be updated as part of the Title V renewal application, A/N 612392, submitted on 5/2/19.)

2. Condition D29.5 provides initial source test requirements for the auxiliary boiler, including the ammonia slip testing. Condition D29.4 currently requires an ammonia slip source test at least

quarterly during the first twelve months of operation and at least annually thereafter for the Auxiliary Boiler SCR, as well as the SCRs for the turbines. The source test method on the current permit is "District method 207.1 and 5.3 or EPA method 17." The "and 5.3 or EPA method 17" will be removed. On 3/23/18, Source Test Engineering Supervising Engineer Mike Garibay was consulted regarding the correct source test method for ammonia testing. Mike explained that South Coast AQMD Method 5.3 or EPA Method 17 were formerly specified as the ammonia sampling methods for a draft ammonia test method using ion chromatography. Subsequently, District Method 207.1 was developed, which included provisions for sampling. When the standard source test method became District Method 207.1, the use of "District method 5.3 or EPA Method 17" for sampling was no longer appropriate.

The auxiliary boiler SCR will be removed from condition D29.4 applicability. A new condition D29.7 will be added for the auxiliary boiler SCR that will incorporate the new requirements of *Rule 1146--Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, amended 12/7/18.*

3. Condition A63.4 sets forth the monthly limits for CO, VOC, PM_{10}, and SOx, with associated emission factors, for the auxiliary boiler. To clarify that $PM_{2.5}$ emissions are conservatively assumed to be equal to PM_{10} emissions, $PM_{2.5}$ is added as a contaminant, with the same emission factor as PM_{10}, to condition A63.4. The $PM_{2.5}$ emission factor that will be added to this condition is the same as the emission factor in existing condition F2.1. Condition F2.1 limits the facility-wide $PM_{2.5}$ emissions to below the applicability limit of *Rule 1325—Federal PM2.5 New Source Review Program, amended 1/4/19.*

California Energy Commission

The California Energy Commission (CEC) is the lead agency for licensing thermal power plants 50 megawatts and larger under the California Environmental Quality Act (CEQA) and has a certified regulatory program under CEQA. Under its certified program, the CEC is exempt from having to prepare an environmental impact report. Its certified program, however, does require environmental analysis of the project, including an analysis of alternatives and mitigation measures to minimize any significant adverse effect the project may have on the environment.

The CEC's certification process subsumes all requirements of local, regional, state, and federal agencies required for the construction of a new plant. The CEC coordinates its review of the proposed facility with the agencies that will be issuing permits to ensure that its certification incorporates the conditions that are required by these various agencies. As the AEC will be rated at greater than 50 megawatts, it is subject to the CEC's certification process.

As discussed above, on 12/27/13, AES submitted an *Application for Certification (AFC)* for the original AEC to the CEC. On 10/26/15, AES submitted a *Supplemental Application for Certification (SAFC)* (13-AFC-01) for the amended AEC. On 4/12/16, AES submitted revised sections for Air

Quality, Biological Resources, and Public Health Assessment to update the *SAFC*. On 4/12/17, the CEC approved the *SAFC* for the amended AEC on 4/12/17 by adopting the Energy Commission Order.

On 4/4/19, AES submitted a *Petition for Post-Certification Amendment, Modification of Gas Turbine Operating Hours and Combined Cycle Gas Turbine (CCGT) Stack Height* ("Petition") to amend the CEC License. The CEC and AES are proceeding with incorporating the other pending application changes that had been submitted to the South Coast AQMD, including for the Auxiliary Boiler and Auxiliary Boiler SCR, into the CEC license for AEC.

PROCESS DESCRIPTION

The numbering below is the same as for the FDOC.

3. A/N 604014--Auxiliary Boiler (for Combined-Cycle Turbines), permitted under A/N 579158

- **Final Determination of Compliance (FDOC) Summary, A/N 579158**
  - *Normal Operations*

    The auxiliary boiler, Babcock & Wilcox (B & W), Model FM 103-88, watertube type, rated at 70.8 MMBtu/hr, assists with the fast start of the combined-cycle turbines. The auxiliary boiler provides enhanced startup times by maintaining the steam cycle in a ready state through the provision of steam for heat recovery steam generator (HRSG) sparging, turbine steam seals, steam pipe warming, condenser deaerating steam, and steam to the fuel gas heater. Prior to a CCGT startup, the auxiliary boiler will increase load from the minimum turndown rate to the maximum load and the produced steam will be directed to the system for HRSG sparging, turbine seals, pipe warming, condenser deaerating and to the fuel gas heater. Once the CCGT completes a startup and the steam turbine reaches maximum output, the auxiliary boiler will reduce load to the minimum turndown firing rate. If extended periods of CCGT outage are expected, the auxiliary boiler could be shut down until a start of the CCGT is expected.

    Under the worst-case maximum month emissions scenario, the boiler will be assumed to continuously operate at 30% load to maintain the CCGT in a ready state condition. Under actual operating conditions, the auxiliary boiler would be used only to maintain steam system readiness and could be shut down and taken offline after a startup of the CCGT and the steam systems have reached maximum output

  - *Commissioning*

    The auxiliary boiler will be commissioned at the AEC site. The commissioning process includes first burner light-off, conditioning, establish the air/fuel ratio curve, and establishing the SCR ammonia injection cure. The commissioning will occur over five days and will require up to 6 fired hours per day. Condition E193.10 will limit the commissioning to 30 hours of fired operation. The daily commissioning emissions will be about the same as two cold starts.

- **A/N 604014 - Condition Change**
  - *Normal Operations*
    The auxiliary boiler purchased and installed is a Cleaver-Brooks, Model NB-200D-50, which is a different make and model than the Babcock & Wilcox (B & W), Model FM 103-88, that was permitted. However, the boiler rating and emissions guarantee will remain the same.

  - *Commissioning*
    In an e-mail dated 5/15/19, Stephen O'Kane indicated 100 hours is needed for commissioning. In a follow-up e-mail dated 5/23/19, Mr. O'Kane provided the following revised process description.

    The commissioning process will be conducted in two phases. The first phase will be the initial burner and SCR tuning, which includes first burner light-off, boiler conditioning, establishing the air/fuel ratio curve, and establishing the SCR ammonia injection curve. During the first phase, the auxiliary boiler will not be permanently connected to the CCGT steam system (HRSG, steam turbine and air cooled condenser) and will vent steam through a temporary by-pass and silencer. As the auxiliary boiler will vent to atmosphere, the first phase will not include steam production up to design pressure at maximum firing rate. After initial tuning, the boiler will be shut down, the temporary by-pass removed and the piping and permanent connections to the CCGT steam system completed. The first phase of commissioning will occur over approximately five days and will require up to 6 fired hours per day. In the event there are issues with boiler tuning and testing, additional startups and commissioning hours will be required.

    The next step will involve the initial startup and commissioning of the combined-cycle turbines, with steam blows of the HRSG, steam turbine and air cooled condenser. Thus the second phase of auxiliary boiler commissioning will be conducted after all permanent connections to the CCGT steam system are completed and the auxiliary boiler can produce design steam pressure for steam seals in the air cooled condenser. The auxiliary boiler will be tested at maximum firing rates and the remainder of the steam system can be commissioned. During CCGT steam system commissioning, the auxiliary boiler will be fired for up to 24 to 36 hours varying between minimum and maximum heat input to complete auxiliary steam system blows. Finally this process will be repeated to test steam supply for creating vacuum and steam seals in the air cooled condenser. The second phase of commissioning will require approximately 70 hours. The entire commissioning process will take a few months to complete in its entirety.

    Condition E193.10 will be revised to limit the commissioning to ~~30~~ **100** hours of fired operation. See Emissions Calculations below for additional condition changes.

4. A/N 613323—Selective Catalytic Reduction for Auxiliary Boiler (A/N 579166)

The auxiliary boiler will be equipped with a selective catalytic reduction system.

- **FDOC Summary, A/N 579166**

  The SCR catalyst will use ammonia injection in the presence of the catalyst to further reduce the NOx concentration in the exhaust gases. Diluted 19% aqueous ammonia vapor will be injected into the exhaust gas stream via a grid of nozzles located upstream of the catalyst. The resulting reaction will reduce NOx to elemental nitrogen and water, resulting in NOx concentrations in the exhaust gas decreasing from 10 ppmv to 5.0 ppmv, all 1-hour averages, dry basis at 3% O_2. The ammonia slip will be limited to 5 ppmvd at 3% O_2. Each SCR will be vented through a dedicated stack, which is 3 feet diameter and 80 feet high.

  The exhaust temperature is required to be between 415 and 628 ºF, as specified in condition no. D12.16. The minimum temperature is required to protect the catalyst face from ammonia salt formation and deposition on a cold catalyst. The maximum temperature is required to maintain catalyst effectiveness. The pressure drop across the catalyst shall be no greater than 2 inches water column, as required by condition no. D12.17. The ammonia flow rate shall be between 0.3 and 1.1 pounds per hour, as required by condition no. D12.15.

- **A/N 613323--Condition Change**

  The change from the original vendor, Babcock & Wilcox, to the selected vendor, Cleaver Brooks, resulted in a change to the recommended ammonia flow rate. For all conditions, the ammonia flow rate shall be between 0.3 and 3.9 lb/hr, as will be required by revised condition D12.15.

EMISSIONS CALCULATIONS

Alamitos Generating Station—Existing Equipment

- **Potential to Emit Calculations**
- Potential to emit emissions for AGS are required to evaluate compliance with *Rule 1303(a)(1)—BACT/LAER (PM_{10}, SOx, VOC, CO)* & *Rule 2005(c)(1)(A)—BACT/LAER (NOx)*, as discussed in the *Rule Evaluation* section below. From the FDOC, the potential to emit emissions are summarized in the table below.

Table 13 - Alamitos Generating Station Potential to Emit Emissions

	Boiler No. 1	Boiler No. 2	Boiler No. 3	Boiler No. 4	Boiler No. 5	Boiler No. 6	AGS Total
CO (tpy)	2937.06	2937.06	3307.28	3307.28	4691.59	4691.59	21,871.86
NO_x (tpy)	66.5	66.5	124.80	124.80	126.5	126.5	635.60
PM_{10} (tpy)	56.6	56.6	106.20	106.20	150.7	150.7	627.0
$PM_{2.5}$ (tpy)	8.83	8.83	16.58	16.58	23.52	23.52	97.86
ROG (tpy)	41	41	76.86	76.86	109	109	453.72
SO_2 (tpy)	4.5	4.5	8.38	8.38	11.9	11.9	49.56

	Boiler No. 1	Boiler No. 2	Boiler No. 3	Boiler No. 4	Boiler No. 5	Boiler No. 6	AGS Total
CO_2 (tpy)	914,554.06	914,554.06	1,716,389.96	1,716,389.96	2,434,814.44	2,434,814.44	10,131,516.92
CH_4 (tpy)	17.24	17.24	32.35	32.35	45.9	45.9	190.98
N_2O (tpy)	1.7	1.7	3.24	3.24	4.59	4.59	19.06
CO_2e (tpy)	915,491.66	915,491.66	1,718,164.23	1,718,164.23	2,437,329.76	2,437,329.76	10,141,971.30

Alamitos Energy Center

3. A/N 604014—Auxiliary Boiler (Combined-Cycle Turbines), 70.8 MMBtu/hr (A/N 579158)

The auxiliary boiler will have a commissioning period and extended startup periods in addition to normal operations.

A. Criteria Pollutants

COMMISSIONING

Note: The FDOC analysis will be revised as a result of the proposed increase of the commissioning period from 30 hr to 100 hr.

- **FDOC Summary, A/N 579158**

  From the AES Response Letter dated 12/11/15, the auxiliary boiler will be commissioned at the AEC site. The commissioning process includes first burner light-off, conditioning, establish the air/fuel ratio curve, and establishing the SCR ammonia injection cure.

  The commissioning will occur over five days and will require up to 6 fired hours per day. Condition E193.10 will limit the commissioning to 30 hours of fired operation. The daily commissioning emissions will be about the same as two cold starts, as shown in the table below:

Table 27 - Auxiliary Boiler Commissioning Emissions

	NOx	CO	VOC
Daily Emissions	8.44	8.68	9.36
Total Commissioning Emissions	42.2	43.4	46.8
Total Fuel Use	~~414 MMBtu or 0.39 MMCF~~ **424.8 MMBtu or 0.405 MMCF Per Stephen O'Kane e-mail, 6/19/19**		

In *Table 27*, the "Daily Emissions" and "Total Commissioning Emissions" are from AES Response Letter dated 12/11/15, item 10.e.ii. The total fuel use is from AES Response E-Mail dated 3/22/16, item 10.e.iv.

From the AES Response Letter dated 1/7/16, the applicant had indicated that the commissioning month emissions will not exceed normal operating month emissions. Condition A63.4 specifies the maximum monthly emissions limits for CO, VOC, PM_{10}, and SOx.

Separate commissioning period emission factors for CO, VOC, PM_{10}, and SOx were not included in condition no. A63.4 because these pollutants are uncontrolled by the SCR and the commissioning period is short. As explained in the Rule 2002 analysis below, condition A99.5 specifies the interim emission factor for NOx prior to CEMS certification is 38.46 lb/mmscf. An interim emission factor for the commissioning was not included for the short commissioning period.

- **A/N 604014—Condition Change**

  In an e-mail dated 5/15/19, Stephen O'Kane indicated condition E193.10 limits the commissioning period to 30 hours but AES will likely need about 100 hours.

  In an e-mail dated 6/12/19, the South Coast AQMD responded that, as discussed in the FDOC, the commissioning duration is required to be limited because condition A195.13 and A195.14 exempts the NOx and CO BACT limits during commissioning. The duration limit constitutes alternative BACT. Condition E193.10 will be increased to limit commissioning to 100 hours in accordance with the revised process description provided by AES.

  The South Coast AQMD provided the following comments to AES in e-mails dated 6/12 and 6/13/19.

  1) New condition A99.6 will be added to set forth the commissioning emission factor for NOx, and commissioning emission factors for CO, VOC, PM_{10}/$PM_{2.5}$, and SOx will be added to condition A63.4. The PM_{10}/$PM_{2.5}$ and SOx commissioning emission factors will be the same as the normal operations emission factors because PM_{10}/$PM_{2.5}$ and SOx are uncontrolled by the SCR and their emissions rates are constant. The commissioning emission factors for NOx, CO, and VOC for the requested 100 hours will be based on the data provided in FDOC *Table 27 - Auxiliary Boiler Commissioning Emissions*, unless updated commissioning data is provided for the first phase of 30 hours and new commissioning data for the second phase of 70 hours.

  2) CO and VOC are not controlled by a CO catalyst. The normal operations EF was based on a normal operating rate of 21.23 MMBtu/hr (30% load). In addition, cold, warm, and hot startups were based on 41.36 MMBtu/hr, which was stated to be provided by the auxiliary boiler vendor. Why are the commissioning emission factors based on *Table 27* significantly higher than the normal operations emissions factors?

3) If supported by commissioning data, commissioning emission factors can be different for Phases 1 and 2. Based on the Cleaver Brooks proposal, dated 3/9/18, the uncontrolled NOx level is 30 ppmvd. It is unclear whether the SCR becomes partially or fully operational during the second phase. It is unclear whether the auxiliary boiler NOx CEMS will be operational during any part of the second phase.

4) Confirmation that the condition A63.4 monthly limits are sufficient for a commissioning month with no normal operations, and a combination month of commissioning and normal operations.

5) Confirmation that the condition I297.7 holding requirement is sufficient for the commissioning year. The condition requires that the facility hold 1351 pounds of NOx RTCs for the first year of operation for the auxiliary boiler. The first year of operation is the commissioning year, for which NOx emissions may be higher than for subsequent normal operating years. AES Response Letter, dated 1/7/16, however, had indicated that commissioning month emissions will not exceed normal operating month emissions. Consequently, the annual NOx emissions for the commissioning year was calculated to be the same as for a normal operating year. The NOx emissions were based on 365 days, 24 cold starts, 48 warm starts, 48 hot start and a NOx emissions rate corresponding to the controlled 5 ppm NOx. However, for at least part of the 100 hr commissioning period, the NOx will be at 30 ppm.

In e-mails dated 6/14 and 6/18/19, AES provided the following information.

A) AES confirmed with the startup engineer and boiler vendor that they can manage the commissioning with the requested 100 total hours of fired operation, the current monthly emission limits in condition A63.4, and the current condition I297.7 NOx RTC holding requirement.

B) The commissioning emission factors that will be added to condition A63.4 and included in new condition A99.6 shall be based on *FDOC Table 27 - Auxiliary Boiler Commissioning Emissions*.

In an e-mail exchange on 6/19/19, AES indicated the total fuel use of 414 MMBtu or 0.39 MMCF that AES provided for *FDOC Table 27* is incorrect. The correct total fuel usage is 424.8 MMBtu or 0.405 MMCF [70.8 MMBTU/hr X 6 hours = 424.800 MMBTU = 0.405 MMCF]. The South Coast AQMD accepted the minor correction in the total fuel use.

The resulting commissioning emission factors for conditions A63.4 and A99.6 are calculated as follows:

NOx Commissioning EF = 42.2 lb/0.405 mmcf = 104.20 lb/mmcf
CO Commissioning EF = 43.4 lb/0.405 mmcf = 107.16 lb/mmcf
VOC Commissioning EF = 46.8 lb/0.405 mmcf = 115.56 lb/mmcf

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NORMAL OPERATIONS

Note: The FDOC analysis for normal operations emissions will remain the same for the proposed increase of the commissioning period from 30 hr to 100 hr, as discussed below.

- **FDOC Summary, A/N 579158**
  Startups/Shutdowns
  A startup event occurs each time the auxiliary boiler is started up. A startup begins with the initiation of combustion, and concludes when BACT emissions levels are achieved. During start-up operations, the boiler operates at elevated average concentration rates for NOx, CO, and VOC due to the phased-in effectiveness of the low NOx burner, flue gas recirculation (FGR), and SCR.

  Three startup scenarios have been developed for the auxiliary boiler.

  1) For a **cold start event**, the auxiliary boiler is at ambient temperature at the time of the startup, which would typically occur if 48 hours or more elapse between a shutdown event and a system startup event. For the cold start event, the time from fuel initiation until reaching the baseload operating rate is expected to take up to 170 minutes.

  2) A **warm start event** would typically be 10 hours or more but less than 48 hours from a shutdown event. The time from fuel initiation until reaching the baseload operating rate is expected to take up to 85 minutes.

  3) A **hot start event** would typically be less than 10 hours of a shutdown event. The time from fuel initiation until reaching the baseload operating rate is expected to take up to 25 minutes.

  For daily emissions (for modeling), the applicant has requested a maximum of one cold start.

  For monthly emissions, the applicant had requested a maximum of 2 cold starts, 4 warm starts, 4 hot starts for the boiler.

For annual emissions, the applicant had requested a maximum of 24 cold starts, 48 warm starts, and 48 hot starts per turbine, equal to 12 times the monthly amounts.

A shutdown scenario need not be developed because, unlike the CTGs, the boiler shuts down almost instantaneously.

The applicant provided maximum startup emissions per event for NOx, CO, and VOC, and startup/shutdown hourly emission rates for NOx, CO, VOC, SO_2 (0.25 gr/100 scf) and $PM_{10/2.5}$ in *Table 5.1-18—Auxiliary Boiler Startup Emission Rates* in the original Application, dated 10/23/15. The revised Application, dated 3/30/16, provided maximum startup emissions per event for SO_2 (corrected to be based on 0.75 gr/100 scf) and PM_{10}. The event emission rates were provided by the manufacturer.

The following table summarizes the emissions for the three types of startup events.

Table 28 – Auxiliary Boiler Start-up Emission Rates

	Duration Minutes (hr)	**NOx lb/event**	**CO lb/event**	**VOC lb/event**	**PM_{10} lb/hr (lb/event)**	**$PM_{2.5}$ lb/hr (lb/event)**	**SO_2 lb/hr (lb/event)**
Cold Start	170 (2.83)	4.22	4.34	4.69	< 0.3 (0.84)	< 0.3 (0.84)	< 0.048 (0.24)
Warm Start	85 (1.42)	2.11	2.17	2.34	< 0.3 (0.42)	< 0.3 (0.42)	< 0.048 (0.12)
Hot Start	25 (0.42)	0.62	0.64	0.69	< 0.3 (0.12)	< 0.3 (0.12)	< 0.048 (0.035)

- *Startup Condition*
  The startup condition limits and minimizes emissions when steady state BACT is not achievable. Condition no. C1.7 provides limits for startups. The limits are necessary because condition nos. A195.13 and A195.14 state that BACT for NO and CO, respectively, shall not apply during startups. The startup limits include: (1) number of cold starts per calendar month and year; (2) number of warm starts per calendar month and year; (3) number of hot starts per calendar month and year; (4) number of startups per day; and (5) duration of cold start, warm start, and hot start; and (6) NOx emissions per cold start, warm start, and hot start.

Emissions Calculations

Operating Schedule per year: 52 wk/yr, 7 days/wk, 24 hr/day
Operating schedule per month: 31 days, two cold starts, four warm starts, four hot starts
Cold start: 170 minutes (2.83 hr)
Warm start: 85 minutes (1.42 hr)
Hot start: 25 minutes (0.42 hr)

Normal operating hrs = (31 days)(24 hr) – (2 cold starts)(2.83 hr/cold start) – (4 warm starts) (1.42 hr/warm start) - (4 hot starts)(0.42 hr/hot start) = 730.98 hr

CO: 50 ppm CO per PSD BACT
NOx: 5 ppmv NOx per Rule 1146(c)(1)(F), amended 11/1/13, and PSD BACT
ROG: Original Application, 10/23/15 : Cleaver Brooks Guarantee, 6/10/15 = 0.003 lb/MMBtu.
AES requested 0.004 lb/MMBtu including safety margin.

Revised Application, 3/30/16, and AES Response e-mail, 4/6/16:
5.5 lb/mmscf = 0.0052 lb/mmbtu (based on 1050 btu/cf).
This is the default Annual Emissions Reporting (AER) emission factor for natural-gas fired boilers.

PM_{10}: Original Application, 10/23/15: Cleaver Brooks Guarantee, 6/10/15 = 0.0043 lb/MMBtu
Revised Application, 3/30/16, and AES Response e-mail, 4/6/16:
7.6 lb/mmscf = 0.0072 lb/MMBtu (based on 1050 btu/cf).
This is the default AER emission factor for natural-gas fired boilers.

SOx: Original Application, 10/23/15: 0.00068 lb/MMBtu (0.25 gr/100 scf) for monthly emissions.
Revised Application, 3/30/16: 0.0020 lb/MMBtu (0.75 gr/100 scf) for monthly emissions.

(In an e-mailed dated 2/2/16, AES clarified that 0.75 grains/100 scf will be used for daily and monthly emissions, instead of the 0.25 grains/100 scf initially proposed.)

Normal Operating Rate:

Original Application, 10/23/15: In AES Response Letter, dated 1/7/16, AES requested that the normal operating emission rate be based on 35.3 MMBtu/hr corresponding to operation at 50% load, because the auxiliary boiler will not be operated at 100% load at all times.

Revised Application, 3/30/16, and AES Response e-mail, 4/6/16: AES requested a monthly heat input limit of 16,055 MMBtu/hr, which is based on a normal operating emission rate of 21.23 MMBtu/hr corresponding to operation at 30% load. Since higher emission factors are to be used for VOC and PM_{10}, the operational profile was reduced to reflect the quantity of VOC and PM_{10} offsets previously secured.

NOx, lbs/hr = (21,230,000 Btu/hr) (8710 dscf/10^6 Btu) (5 ppm per Rule 1146/10^6) (20.9/(20.9-3.0)) (46 lbs NOx/385 scf) = 0.13 lb/hr, normal operating rate (see below for NSR Database Entry hourly rate)

lbs/month = (730.98 hr)(0.13 lb/hr) + (2 cold starts)(4.22 lb/cold start) + (4 warm starts)(2.11 lb/warm start) + (4 hot starts)(0.62 lb/hot start) = 114.39 lb/month = 0.057 tons/month [.68 tpy]

lbs/day = (114.39 lb/month)/(30 days) = 3.81 lb/day
30 DA = 3.81 lb/day

NSR Database Entry: (3.81 lb/day)(day/24 hr) = 0.16 lb/hr

CO, lbs/hr = (21,230,000 Btu/hr) (8710 dscf/10^6 Btu) (50 ppm CO per guarantee /10^6) (20.9/(20.9-3.0)) (28 lbs CO/379 scf) = 0.80 lb/hr, normal operating rate (see below for NSR Database Entry hourly rate)

lbs/month = (730.98 hr)(0.80 lb/hr) + (2 cold starts)(4.34 lb/cold start) + (4 warm starts) (2.17 lb/warm start) + (4 hot starts)(0.64 lb/hot start) = 604.70 lb/month = 0.30 tons/month [3.6 tpy]

lbs/day = (604.70 lb/month)/(30 days) = 20.16 lb/day
30 DA = 20.16 lb/day

NSR Database Entry: (20.16 lb/day)(day/24 hr) = 0.84 lb/hr

ROG, lbs/hr = (21,230,000 Btu/hr) (0.0052 lb/MMBtu /10^6) = 0.11 lb/hr, normal operating rate (see below for NSR Database Entry hourly rate)

lbs/month = (730.98 hr)(0.11 lb/hr) + (2 cold starts)(4.69 lb/cold start) + (4 warm starts) (2.34 lb/warm start) + (4 hot starts)(0.69 lb/hot start) = 101.91 lb/month = 0.051 tons/month [0.61 tpy]

lbs/day = (101.91 lb/month)/(30 days) = 3.40 lb/day
30 DA = 3.40 lb/day

NSR Database Entry: (3.40 lb/day)(day/24 hr) = 0.14 lb/hr

For combustion emissions, the standard assumption is PM_{10} = PM.
PM_{10}, lbs/hr = (21,230,000 Btu/hr) (0.0072 lb/MMBtu/10^6) = 0.15 lb/hr, normal operating rate (see below for NSR Database Entry hourly rate)

lbs/month = (730.98 hr) (0.15 lb/hr) + (2 cold starts) (0.84 lb/cold start)
+ (4 warm starts)(0.42 lb/warm start) + (4 hot starts)(0.12 lb/hot start)
= 113.49 lb/month = 0.057 tons/month [0.68 tpy]

lbs/day = (113.49 lb/month)/(30 days) = 3.78 lb/day
30 DA = 3.78 lb/day
NSR Database Entry: (3.78 lb/day)(day/24 hr) = 0.16 lb/hr

SOx, lbs/hr = (21,230,000 Btu/hr) (0.002 lb/MMBtu/10^6) = 0.042 lb/hr, normal operating rate (see below for NSR Database Entry hourly rate)

lbs/month = (730.98 hr) (0.042 lb/hr) + (2 cold starts) (0.24 lb/cold start) +
(4 warm starts)(0.12 lb/warm start) + (4 hot starts)(0.035 lb/hot start) =
31.80 lb/month = 0.016 tons/month [0.19 tpy]

lbs/day = (31.80 lb/month)/(30 days) = 1.06 lb/day
30 DA = 1.06 lb/day

NSR Database Entry: (1.06 lb/day)(day/24 hr) = 0.04 lb/hr

- *Monthly Emissions Limit*
  Condition A63.4 limits the maximum monthly emissions limits for CO, VOC, PM_{10}, and SOx. From the calculations above, CO will be limited to 605 lbs, VOC to 102 lbs, PM_{10} to 113.5 lbs, and SOx to 32 lbs.

  As the first step to deriving emission factors, the monthly gas usage is derived. The revised Application, dated 3/30/16, was based on a normal operating rate of 21.23 MMBtu/hr (30% load). Cold, warm, and hot startups were based on 41.36 MMBtu/hr, which was stated to be provided by the auxiliary boiler vendor.

  Maximum monthly fuel consumption (MMBtu/month) = [(no. normal operating hours) * (21.23 MMBtu/hr)] + {[(no. startups, cold) (hr/startup, cold) + (no. startups, warm) (hr/startup, warm) + (no. startups, hot) (hr/startup, hot)] * [(41.36 MMBtu/hr)]} =

  [(730.98 hr) * (21.23 MMBtu/hr)] + {[((2 cold starts)(2.83 hr/cold start) + (4 warm starts)(1.42 hr/warm start) + (4 hot starts)(0.42 hr/hot start)) * (41.36 MMBtu/hr)]} = 16,057 MMBtu/month

  (16,057 MMBtu/month) (MMscf/1050 MMBtu) = 15.29 mmscf/month

The normal operating emission factors were derived below for inclusion in condition no. A63.4 for CO, VOC, PM_{10}, and SOx. As explained in the Rule 2002 analysis below, condition A99.5 specifies the interim emission factor for NOx prior to CEMS certification is 38.46 lb/mmscf.

The normal operating month emission factors are shown in the table below.

Table 29 - Auxiliary Boiler Emission Factors

Pollutants	Maximum Monthly Emissions, lb/month	Emission Factors, lb/mmcf
CO	604.70	39.55
VOC	101.91	6.67
PM_{10}	113.49	7.42
SOx	31.80	2.08

Emission factor, lb/mmcf = (lb/month) (month/15.29 mmscf)

- *Annual Emissions Limit*

The monthly emissions limits in condition A63.4 are applicable each and every month. Therefore, the annual emissions limits are the monthly emissions limits multiplied by twelve months, unless the annual emissions are limited by permit condition.

The applicant had not requested that annual emissions be limited to less than the monthly emissions limit multiplied by 12 months. In actuality, the annual emissions will be less than 12 times the monthly emissions, because the annual emissions are based on 365 days but the monthly emissions are based on 31 days.

The number of RECLAIM NOx RTCs required are determined on an annual basis which will be reflected in condition I297.7, as discussed under the Rule 2005(c)(2) analysis. The use of the interim emission factor of 38.46 lbs/mmscf for the entire year would result in unrealistically high annual emissions. The expected annual NOx emissions are calculated below.

Operating schedule per month: 365 days, 24 cold starts, 48 warm starts, 48 hot starts

Normal operating hrs = (365 days)(24 hr) – (24 cold starts)(2.83 hr/cold start) – (48 warm starts)(1.42 hr/warm start) - (48 hot starts)(0.42 hr/hot start) = 8603.76 hr

NOx, lbs/yr = (8603.76 hr)(0.13 lb/hr) + (24 cold starts)(4.22 lb/cold start) + (48 warm starts)(2.11 lb/warm start) + (48 hot starts)(0.62 lb/hot start) = 1350.8 lb/yr (0.68 tpy)

The annual gas usage is calculated below for use in the toxic emissions and greenhouse gas emissions calculations below.

Maximum annual fuel consumption (MMBtu/month) = [(no. normal operating hours) * (21.23 MMBtu/hr)] + [((no. startups, cold) (hr/startup, cold) + (no. startups, warm) (hr/startup, warm) + (no. startups, hot) (hr/startup, hot)) * (41.36 MMBtu/hr)] =

[(8603.76 hr) * (21.23 MMBtu/hr)] + [((24 cold starts)(2.83 hr/cold start) +
(48 warm starts)(1.42 hr/warm start) + (48 hot starts)(0.42 hr/hot start)) * (41.36 MMBtu/hr)] = 189,119.91 MMBtu/yr

- **A/N 604014—Condition Change**
  Same as FDOC, with no change to emissions. As discussed above, AES has confirmed that the current monthly limits in condition A63.4 for CO, VOC, PM_{10}, $PM_{2.5}$, and SOx, as well as the current condition I297.7 RTC holding requirement for NOx, are sufficient for the increase in commissioning duration from 30 to 100 hours.

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B. Toxic Pollutants

- **FDOC Summary, A/N 579158**
  As required by the South Coast AQMD, the emission factors were based on the Ventura County Air Pollution Control District (VCAPCD) emission factors for natural gas fired external combustion equipment rated 10 – 100 MMBtu/hr. The emissions rates are for use in the Rule 1401 health risk assessment below.

Table 30 - Auxiliary Boiler Toxic Air Contaminants/Hazardous Air Pollutants

Compound	CAS	TAC/HAP	Emission Factor (lb/MMcf)	Emission Factor (lb/MMBtu)[1]	Lb/hr	Lb/yr	TPY
Ammonia[2]	766417	TAC			0.16	423	0.212
Acetaldehyde	75070	TAC & HAP	0.0031	2.95E-06	2.09E-04	0.558	2.79E-04
Acrolein	107028	HAP & TAC	0.0027	2.57E-06	1.82E-04	0.486	2.43E-04
Benzene	71432	HAP & TAC	0.0058	5.52E-06	3.91E-04	1.04	5.22E-04
Ethylbenzene	100414	HAP & TAC	0.0069	6.57E-06	4.65E-04	1.24	6.22E-04
Formaldehyde	50000	HAP & TAC	0.0123	1.17E-05	8.29E-04	2.22	1.11E-03
Hexane	110543	HAP & TAC	0.0046	4.38E-06	3.10E-04	0.829	4.14E-04
Naphthalene	91203	HAP & TAC	0.0003	2.86E-07	2.02E-05	0.054	2.70E-05
PAHS (excluding naphthalene)	1151	HAP & TAC	0.0001	9.5E-08	6.74E-06	0.018	9.01E-06

Compound	CAS	TAC/HAP	Emission Factor (lb/MMcf)	Emission Factor (lb/MMBtu)[1]	Lb/hr	Lb/yr	TPY
Propylene[2]	115071	TAC	0.5300	5.05E-04	3.57E-02	95.5	4.77E-02
Toluene	108883	HAP & TAC	0.0265	2.52E-05	1.79E-03	4.77	2.39E-03
Xylene	1330207	HAP & TAC	0.0197	1.88E-05	1.33E-03	3.55	1.77E-03
Total Annual HAPS Emissions, TPY							**0.0074**
Total Annual Toxic Air Contaminants Emissions, TPY							**0.27**

1 Ventura County APCD emissions factors are provided in lb/MMcf. The natural gas heat content of 1050 MMBtu/MMscf was used for conversion to lb/MMBtu.

2 Ammonia and propylene are toxic air contaminants for the purpose of Rule 1401, but not federal hazardous air pollutants.

The hourly and annual emissions are calculated as follows:

For compounds other than ammonia
Hourly emissions, lb/hr = (Emission Factor) (70.8 MMBtu/hr max rating of boiler)

Annual emissions, lb/yr = (Emission Factor) (average annual heat input rate of 189,119.91 MMBtu/yr)

Ammonia
Maximum hourly emissions, lb/hr = (70.8 MMBtu/hr) (8710 dscf/10^6 Btu) (5 ppm NH_3 /10^6) (20.9/(20.9-3.0)) (17 lbs NH_3/379 scf) = 0.16 lb /hr

Maximum annual emissions, lb/yr = (365 day/yr)(24 hr/day)(0.05 lb/hr at 30% load) = 423 lb/yr = 0.22 tpy

- **A/N 604014—Condition Change**
  Same as FDOC, with no change to emissions.

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C. Greenhouse Gases (GHG)

- **FDOC Summary, A/N 579158**
  Combustion of natural gas in the boiler will result in emissions of CO_2, CH_4, and N_2O.

  As shown above for the toxic pollutants emissions calculations, the average annual heat input rate was 189,119.91 MMBtu/yr.

  CO_2: 53.06 kg CO_2/MMBtu
  CH_4 : 1 g CH_4/MMBtu
  N_2O: 0.10 g N_2O/MMBtu

CO_2 = (189,119.91 MMBtu/yr)(53.06 kg/MMBtu)(2.2046 lb/kg)
= 22,122,504.97 lb/yr = 11,061.25 tpy

CH_4 = (189,119.91 MMBtu/yr)(1 g/MMBtu)(2.205 x 10^{-3} lb/g)
= 417.01 lb/yr = 0.21 tpy

N_2O = (189,119.91 MMBtu/yr)(0.1 g/MMBtu)(2.205 x 10^{-3} lb/g)
= 41.70 lb/yr = 0.02 tpy

CO_2e = (22,122,504.97 lb/yr CO_2)(1 lb CO_2e/lb CO2) + (417.01 lb/yr CH_4)
(25 lb CO2e/lb CH_4) + (41.70 lb/yr N_2O)(298 lb CO_2e/lb N_2O)
= 22,145,356.82 lb/yr = 11,072.68 tpy = = 922.72 tons/month

New Source Review (NSR) Database Entries
This section develops the internal NSR Data Summary Sheet entries.

Operating Schedule: 52 wks/yr, 7 days/wk, 24 hrs/day (annualized schedule)
→ 8736 hr/yr

The hourly emissions are back calculated from the annual emissions and used for the purpose of input for the internal NSR Data Summary Sheet only.

CO_2 = (22,122,504.97 lb/yr) (yr /8736 hr) = 2532.34 lb/hr

CH_4 = (417.01 lb/yr) (yr /8736 hr) = 0.048 lb/hr

N_2O = (41.70 lb/yr) (yr /8736 hr) = 0.005 lb/hr

- **A/N 604014—Condition Change**
  Same as FDOC, with no change to emissions.

4. A/N 613323—Selective Catalytic Reduction for Auxiliary Boiler (A/N 579166)

- **FDOC Summary, A/N 579166**
  Operating Schedule: 52 wk/yr, 7 days/wk, 24 hrs/day

A. Criteria Pollutants
NOx = CO = VOC = PM_{10} = SOx = 0 lb/hr = 0 lb/day

B. Toxic Pollutants
From *Table 30* above, the 5 ppmvd BACT level for ammonia results in an annual emission rate of 423 lb/yr = 0.21 ton/yr = 0.018 ton/month (avg)

To calculate R1 and R2 for annualized operating schedule (52 wk/yr, 7 days/wk, 24 hr/day, same as CTGs).

NH_3, lb/day = (423 lb/yr) (yr/52 wk) (wk/7 days) = 1.16 lb/day
lb/hr = (1.16 lb/day) (day/24 hr) = 0.05 lb/hr

Note: Ammonia is not a federal HAP.

- **A/N 613323—Condition Change**
  Same as FDOC, with no change to emissions.

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RULE EVALUATION

The modified AEC project is expected to comply with all applicable South Coast AQMD rules and regulations, and federal and state regulations, as follows:

SOUTH COAST AQMD RULES AND REGULATIONS

Rule 205—Expiration of Permit to Construct

Section 70.6 of 40 CFR Part 70 and South Coast AQMD Rule 3004(a) and (b) require each Title V permit to include emission limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements, at the time of permit issuance.

Rule 205, 40 Part 52.21(r)(2), and Rule 1713(c) provide expiration requirements for permits to construct.

Rule 205—This rule provides that a permit to construct shall expire one year from the date of issuance unless an extension of time has been approved in writing by the Executive Officer. This requirement is set forth in condition 1.b in Section E: Administrative Conditions of the facility permit. Section E is comprised of a standard list of operating conditions that apply to all permitted equipment at the facility unless superseded by condition(s) listed elsewhere in the permit.

40 Part 52.21--Rule 1714(c) incorporates by reference the provisions of 40 Part 52.21--Prevention of Significant Deterioration of Air Quality. Part 52.21(r)(2) states: "Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date."

§52.21(j)(4) states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source."

Rule 1713, adopted 10/7/88--Rule 1713(c) states: "A permit to construct shall become invalid if construction is not commenced within 24 months after receipt of such approval, if construction is discontinued for a period of 24 months or more, or if construction is not completed within a reasonable time. The Executive Officer may extend the 24-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 24 months of the projected and approve commencement date."

The requirements for Rule 205, 40 Part 52.21, and Rule 1713 are consolidated in conditions E74.1 and E193.5.

Analysis:

Condition E74.1 requires BACT/LAER determination for Phase II to be reviewed and modified by the South Coast AQMD no later than 18 months prior to the commencement of construction of Phase II. This condition is not applicable to the Auxiliary Boiler, which is part of Phase I.

Because the AEC project is a multi-year, multi-phase project, condition E193.5 sets forth requirements for the extension of the expiration date for the Permits to Construct. On 4/17/18, the South Coast AQMD extended the expiration date of all Permits to Construct to 4/17/19. On 4/12/19, the South Coast AQMD extended the expiration date of all Permits to Construct to 4/17/20. Since the construction of the combined-cycle units (Power Block 1, Phase 1) was initiated on 8/7/17, which is within one year of the date of issuance of the Permits to Construct on 4/18/17, condition E193.5 did not require the Permits to Construct for Phase 1 to be extended. AES requested the one-year extensions as recommended by the South Coast AQMD.

Rule 212—Standards for Approving Permits
Rule 2005(h) –Public Notice for RECLAIM *(requires compliance with Rule 212)*
Public notice is **not** required for this project, as discussed below.

- ***Rule 212(c)(1)***
  Public notice is required for any new or modified equipment under Regulation XXX (Title V) that may emit air contaminants located within 1000 feet from the outer boundary of a school, unless the modification will result in a reduction of emissions of air contaminants from the facility and no increase in health risk at any receptor location.

Analysis:
CA Health & Safety 42301.9 defines "school" to mean any public or private school used for purposes of the education of more than 12 children in kindergarten or any of grades 1 to 12, inclusive, but does not include any private school in which education is primarily conducted in private homes. The nearest K-12 school—Rosie the Riveter Charter High School, 690 N. Studebaker Road, Long Beach, CA 90803-- is located 971 feet away from the closest combined-cycle turbine. The school is located outside the entrance to the facility. All students participate in both high school and vocational training. The current enrollment is approximately 64 students in grades 9^{th} – 12^{th}.

This subparagraph will **not** require public notice for the condition changes to the Auxiliary Boiler and SCR because the changes will not result in emissions increases of criteria pollutants or toxic air contaminants.

- ***Rule 212(c)(2)***
  Public notice is required for any new or modified facility which has on-site emission increases exceeding any of the daily maximums specified in subdivision (g) of this rule.

  Analysis:
  This subparagraph will **not** require public notice because the condition changes will not result in on-site emissions increases of criteria pollutants.

- ***Rule 212(c)(3)***
  Public notice is required for any new or modified equipment under Regulation XX or XXX with increases in emissions of toxic contaminants for which a person may be exposed to a maximum individual cancer risk greater than, or equal to one in a million during a lifetime (70 years) for facilities with more than one permitted unit, unless the applicant demonstrates to the satisfaction of the Executive Officer that the total facility-wide maximum individual cancer risk is below ten in a million using the risk assessment procedures and toxic air contaminants specified under Rule 1402.

  Analysis:
  This subparagraph will **not** require public notice because the changes will not result in emissions increases of toxic air contaminants.

Rule 218 – Continuous Emission Monitoring
The FDOC discussed that the combined- and simple-cycle turbines are each equipped with an oxidation catalyst to control CO emissions. A CO CEMS is required to be installed on each turbine to demonstrate compliance with the CO emission limit. The FDOC did **not** require the auxiliary boiler to be equipped with a CO CEMS because the boiler is not equipped with an oxidation catalyst. The boiler burner design controls CO to 50 ppmv at 3% O_2. There is no regulatory requirement for the auxiliary boiler to be equipped with a CO CEMS.

In accordance with paragraphs (c), (e), (f), the facility is required to submit an "Application for CEMS" for each CO CEMS and adhere to retention of records requirements and reporting requirements once approval to operate the CO CEMS is granted. Subsequent to the issuance of the permits to construct on 4/18/17, AES submitted a CEMS application on 8/22/18 for a CO CEMS (Rule 218) and a NOx CEMS (RECLAIM). In a letter dated 2/20/19, South Coast AQMD Source Test Engineering granted initial approval for both CEMS.

Condition D82.4 will be added to the auxiliary boiler permit to provide requirements for the CO CEMS. Source Test Sr. Engineer Brian Speaks had evaluated and granted the initial approval for the CO and NOx CEMS application for the auxiliary boiler. On 6/27/19, he confirmed that the requirements in existing condition D82.1 for the CO CEMS for the turbines, with the exception of the CO emission rate equation, would be correct for new condition D82.4.

Rule 401 – Visible Emissions

This rule prohibits the discharge of visible emissions for a period aggregating more than three minutes in any one hour which is as dark or darker in shade than Ringelmann No. 1. Visible emissions are not expected from the auxiliary boiler and SCR because the boiler will be fired exclusively on pipeline quality natural gas.

Rule 402 – Nuisance

This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property. Nuisance problems are not expected from the auxiliary boiler and SCR during normal operation.

Rule 403 – Fugitive Emissions

The purpose of this rule is to reduce the amount of particulate matter entrained in the ambient air as a result of man-made fugitive dust sources by requiring actions to prevent, reduce, or mitigate fugitive dust emissions. The provisions of this rule apply to any activity or man-made condition capable of generating fugitive dust. This rule includes the prohibition of fugitive dust emissions that remains visible in the atmosphere beyond the property line of the emission source.

During normal operations, fugitive emissions are not expected from the operation of the auxiliary boiler and SCR. Compliance with Rule 403 is expected.

Rule 407 – Liquid and Gaseous Air Contaminants

This rule limits combustion equipment emissions to 2000 ppmv CO. The auxiliary boiler is expected to comply with the BACT limit of 50 ppmv CO.

The SO_2 portion of the rule does not apply per subdivision (c)(2), because the natural gas fired in the auxiliary boiler will comply with the sulfur limit in Rule 431.1. Therefore, compliance with this rule is expected.

Rule 409 – Combustion Contaminants
This rule restricts the combustion generated PM emissions from combustion equipment to 0.23 grams per cubic meter (0.1 grain per cubic foot) of gas, calculated to 12% CO_2, averaged over 15 minutes.

With the use of natural gas, the operation of the boiler is anticipated to comply with the limit of 0.1 grains per cubic foot of gas corrected to 12 percent of carbon dioxide.

Rule 431.1 – Sulfur Content of Gaseous Fuels
The natural gas supplied to the gas turbines and auxiliary boiler is expected to comply with the 16 ppmv sulfur limit (calculated as H_2S) specified in this rule, because commercial grade natural gas has an average sulfur content of 4 ppm.

Rule 474—Fuel Burning Equipment-Oxides of Nitrogen, amended 12/4/81
Rule 474 was most recently amended on 12/4/81. Therefore, the rule continues to be superseded by NOx RECLAIM pursuant to *Rule 2001--Applicability*, amended ***10/5/18***, *Table 1—Rules Not Applicable To RECLAIM Facilities For Requirements Pertaining To NOx Emissions If Rule Was Adopted Or Amended Prior To October 5, 2018.*

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Rule 1146—Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters, amended 12/7/18
Note: ***Rule 1146*** refers to new ***Rule 1100—Implementation Schedule for NOx Facilities, adopted 12/7/18***, and ***Rule 1100*** refers to ***Rule 1146, amended 12/7/18***. The rule analysis for ***Rule 1100*** is presented below, immediately following the analysis for ***Rule 1146***.

The ***FDOC*** provided an analysis of *Rule 1146, amended* ***11/1/13***, for the auxiliary boiler. NOx emissions from the auxiliary boiler were not subject to this rule, because this rule was superseded by NOx RECLAIM pursuant to *Rule 2001--Applicability, amended* ***12/4/15***, *Table 1—Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions.* However, the CO emissions were subject to this rule.

For ***A/N 604014 & 613323*** under evaluation here, an analysis of *Rule 1146, amended* ***12/7/18***, will be performed below. *Rule 2001--Applicability*, amended ***10/5/18***, *Table 1—Rules Not Applicable To RECLAIM Facilities For Requirements Pertaining To NOx Emissions If Rule Was Adopted Or Amended Prior To October 5, 2018* no longer exempts NOx emissions at this facility from *Rule 1146, amended* ***12/7/18***. CO emissions continue to be subject to this rule.

(a) Applicability
This rule applies to boilers, steam generators, and process heaters of equal to or greater than 5 million Btu per hour rated heat input capacity used in all industrial, institutional, and commercial operations.

Analysis: The auxiliary boiler, rated at 70.8 MMBtu/hr, is subject to this rule.

(b) Definitions
(9) GROUP II UNIT means any unit burning gaseous fuels, excluding digester and landfill gases, with a rated heat input capacity less than 75 million Btu per hour down to and including 20 million Btu per hour, excluding thermal fluid heaters and units operated at schools and universities.

Analysis: The auxiliary boiler, rated at 70.8 MMBtu/hr, is a Group II unit.

(c) Requirements
Notwithstanding the exemptions contained in Rule 2001 – Applicability, Table 1 – Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions If Rule Was Adopted or Amended Prior to October 5, 2018, the owner or operator of any unit(s) subject to this rule shall not operate the unit in a manner that exceeds the applicable emission limits specified in paragraphs (c)(1), (c)(2), (c)(3), and (c)(4).

(1) The owner or operator shall subject all of the units within the facility to the applicable NOx emission limits specified in Table 1146-1:

Table 1146-1 – NOx Emission Limits and Compliance Schedule

Rule Reference	Category	Limit [1]	Compliance Schedule for Non-RECLAIM Facilities	Compliance Schedule for RECLAIM and Former RECLAIM Facilities
(c)(1)(G)	Group II Units (Fire-tube boilers with a previous NOx limit less than or equal to 9 ppm and greater than 5 ppm prior to December 7, 2018)	7 ppm or 0.0085 lbs/10^6 Btu	See (c)(7)(A)	See Rule 1100 – Implementation Schedule for NOx Facilities
(c)(1)(H)	Group II Units (All others with a previous NOx limit less than or equal to 12 ppm and greater than 5 ppm prior to December 7, 2018)	9 ppm or 0.011 lbs/10^6 Btu	January 1, 2014	
(c)(1)(I)	Group II Units	5 ppm or	December 7, 2018	

	(All others)	0.0062 lbs/10^6 Btu		

[1] All parts per million (ppm) emission limits are referenced at 3 percent volume stack gas oxygen on a dry basis averaged over a period of 15 consecutive minutes.

Analysis:

The auxiliary boiler is a watertube boiler with a NOx limit of 5.0 ppmvd at 3% O_2 (1-hr average), as required by the Permit to Construct issued on 4/18/17. The boiler is in the process of being installed. The 5.0 ppmvd NOx limit was imposed as a result of the top-down PSD BACT analysis performed for Rule 1703(a)(2)-PSD-BACT in the FDOC. Condition A195.13 specifies the NOx limit is 5.0 ppmvd (1-hr average) pursuant to PSD-BACT, and condition D29.5 requires an initial source test.

Rule 1146(c)(1)(I) requires a NOx limit of 5 ppmvd at 3% O_2 (15-minute average). As discussed in the Rule 1100 analysis below, Rule 1100(d)(1)(B) provides a deadline of 1/1/21 for the 5 ppmvd NOx limit for RECLAIM facilities. The auxiliary boiler is already in compliance with the 5 ppmvd NOx limit.

Footnote 1 to *Table 1146-1 – NOx Emission Limits and Compliance Schedule* states: "All parts per million (ppm) emission limits are referenced at 3 percent volume stack gas oxygen on a dry basis averaged over a period of 15 consecutive minutes." The 5 ppmvd NOx and 50 ppmvd CO limits are imposed pursuant to BACT. BACT requires a 1-hour averaging time. Accordingly, initial source testing condition D29.5 requires 1-hour averaging times for NOx, CO, VOC, and NH_3, which all have BACT limits. In addition, the sampling times for PM_{10} and $PM_{2.5}$ are 1 hour or longer as necessary to obtain a measurable sample. The source test results for $PM_{2.5}/PM_{10}$ will be used to validate the emission factor for the purpose of Rule 1325 compliance. Three runs are necessary to validate an emission factor.

The current 1-hour averaging time set forth in conditions A195.13 and D29.5 per PSD-BACT will <u>not</u> be revised to a 15-minute averaging time at this time because the NOx limit of 5 ppmvd at 3% O_2 (15-minute average) per Rule 1146(c)(1)(I) will not be applicable to RECLAIM facilities until 1/1/21.

(2) The owner or operator of any unit(s) operating with air pollution control equipment that results in ammonia emissions in the exhaust shall not discharge into the atmosphere ammonia emissions in excess of 5 ppm (referenced at 3 percent volume stack gas oxygen on a dry basis averaged over a period of 60 consecutive minutes), except for units complying with
paragraph (c)(9).

Analysis:

For the Auxiliary Boiler SCR, the ammonia limit is 5.0 ppmvd at 3% O_2 (1-hr average), pursuant to condition D195.16. The 5 ppmvd NH_3 limit was imposed as a result of the Rule 1303(a)(1) BACT/LAER analysis in the FDOC. Condition D29.5 requires an initial source test, including the ammonia slip, for the Auxiliary Boiler. As discussed below, condition D29.7 will provide requirements for the periodic compliance testing provided in (d)(3)(A).

(4) The owner or operator of any unit(s) with a rated heat input capacity greater than or equal to 5 million Btu per hour shall not discharge into the atmosphere carbon monoxide (CO) emissions in excess of 400 ppm (referenced at 3 percent volume stack gas oxygen on a dry basis averaged over a period of 15 consecutive minutes) or for natural gas fired units 0.30 lbs/10^6 Btu.

Analysis:
The CO limit is 50 ppmvd at 3% O_2 (1-hr average), as required by the Permit to Construct issued on 4/18/17. The 50 ppmvd CO limit was imposed as a result of the top-down PSD BACT analysis performed for Rule 1703(a)(2)-PSD-BACT in the FDOC. Condition A195.14 specifies the limit is 50.0 ppm (1-hr average) pursuant to PSD-BACT, and condition D29.5 requires an initial source test. **The current 1-hour averaging time set forth in conditions A195.14 and D29.5 per PSD-BACT will not be revised to a 15-minute averaging time because the 50 ppmvd CO (1-hr average) limit is more stringent than the 400 ppmvd (15-minute average) limit in Rule 1146(c)(4).**

(6) Notwithstanding the exemptions contained in Rule 2001 – Applicability, Table 1 – Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions If Rule Was Adopted or Amended Prior to October 5, 2018, any unit(s) with a rated heat input capacity greater than or equal to 40 million Btu per hour and an annual heat input greater than 200 x 10^9 Btu per year shall have a continuous in-stack nitrogen oxides monitor or equivalent verification system in compliance with Rule 218, Rule 218.1, and 40 CFR Part 60 Appendix B Specification 2. Maintenance and emission records shall be maintained and made accessible for a period of two years to the Executive Officer.

Analysis:
For the **FDOC**, this NOx requirement was not applicable to the auxiliary boiler, because Rule 1146, amended 11/1/13, was superseded by NOx RECLAIM pursuant to *Rule 2001--Applicability, amended **12/4/15**, Table 1—Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions*. Pursuant to *Rule 2012--RECLAIM Monitoring Recording and Recordkeeping Requirements*, the auxiliary boiler is classified as a "major NOx source." As such, the boiler was required to be equipped with a certified CEMS to meet RECLAIM requirements.

For **A/N 604014 & 613323** under evaluation here, *Rule 1146, amended **12/7/18***, is no longer superseded for the auxiliary boiler by NOx RECLAIM. *Rule 2001--Applicability*, amended ***10/5/18***, *Table 1—Rules Not Applicable To RECLAIM Facilities For Requirements Pertaining To NOx Emissions If Rule Was Adopted Or Amended Prior To October 5, 2018* does not exempt NOx emissions from *Rule 1146, amended **12/7/18***.

Rule 1100—Implementation Schedule for NOx Facilities, however, provides clarifying applicability requirements for Rule 1146, as follows:

> (e) The applicable monitoring, reporting, and recordkeeping requirements are as follows:
>
> (1) For Title V facilities, an owner or operator of a RECLAIM facility shall comply with the monitoring, reporting, and recordkeeping requirements specified in Rule 2012.
> (2) Except for Title V facilities, the owner or operator of a RECLAIM facility that becomes a former RECLAIM facility shall comply with the monitoring, reporting, and recordkeeping requirements in the applicable rule(s) as specified in subdivision (b) [Rule 1146] upon the date the facility becomes a former RECLAIM facility.

As the facility is Title V and RECLAIM, Rule 1100(e)(1) is applicable. Therefore, the auxiliary boiler will continue to be required to meet Rule 2012, including being equipped with a certified CEMS to meet RECLAIM requirements. Condition D82.3 currently provides RECLAIM requirements for the CEMS. This condition does not need to be updated and revised to meet the new requirements of Rule 1146(c)(6).

(d) Compliance Determination
The owner or operator of any unit(s) subject to this rule shall meet the following requirements for determining compliance:

(2) All emission determinations shall be made in the as-found operating condition, except no compliance determination shall be established during start-up, shutdown, or under breakdown conditions. Start-up and shutdown intervals shall not last longer than is necessary to reach stable conditions. Compliance determination as specified in paragraph (d)(6) shall be
conducted at least 250 operating hours, or at least thirty days subsequent to the tuning or servicing of any unit, unless it is an unscheduled repair.

(3) An owner or operator of a unit subject to the ammonia emission limit specified in paragraph (c)(2) shall:

(A) Conduct quarterly a source test to demonstrate compliance with the ammonia emission limit, according to the procedures in District Source Test Method 207.1 for Determination of Ammonia Emissions from Stationary Sources, during the first 12 months of unit operation and thereafter, except that source tests may be conducted annually within 12 months thereafter when four consecutive quarterly source tests demonstrate compliance with the ammonia emission limit. If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the ammonia emissions limits prior to resuming annual source tests; or

(B) Utilize an ammonia Continuous Emissions Monitoring System (CEMS) certified under an approved SCAQMD protocol to demonstrate compliance with the ammonia emission limit.

Analysis:
Condition D29.4 currently requires an ammonia slip source test at least quarterly during the first twelve months of operation and at least annually thereafter for the SCRs for the combined-cycle turbines, simple-cycle turbines, and auxiliary boiler. The auxiliary boiler SCR will be removed from condition D29.4 applicability. A new condition D29.7 will be added for the auxiliary boiler SCR that will incorporate the new requirements of Rule 1146(d)(3)(A) for periodic compliance testing.

(4) Compliance with the NOx and CO emission requirements of paragraphs (c)(1), (c)(3), and (c)(4) and the stack-gas oxygen concentration requirement of subparagraph (c)(5)(A) shall be determined using a District approved contractor under the Laboratory Approval Program according to the following procedures:

(A) District Source Test Method 100.1 - Instrumental Analyzer Procedures for Continuous Gaseous Emission Sampling (March 1989), or ….

(F) a continuous in-stack nitrogen oxide monitor or equivalent verification system as specified in paragraph (c)(6).

Records of all source tests shall be made available to District personnel upon request. Emissions determined to exceed any limits established by this rule through the use of any of the above-referenced test methods shall constitute a violation of this rule.

Analysis:
Initial source testing condition D29.5 requires the use of a LAP-approved contractor and Method 100.1 for NOx and CO.

(6) Compliance determination with the NOx emission requirements in paragraph (d)(4) shall be conducted once:

(A) every three years for units with a rated heat input capacity greater than or equal to 10 million Btu per hour, except for units subject to paragraph (c)(6).

(7) Provided the emissions test is conducted within the same calendar year as the test required in paragraph (d)(6), an owner or operator may use the following emissions tests to comply with paragraph (d)(6):
(A) Periodic monitoring or testing of a unit as required in a Title V permit pursuant to Regulation XXX, or
(B) Relative accuracy testing for continuous emissions monitoring verification pursuant to Rule 218.1 or 40 CFR Part 60 Appendix B Specification 2.

(8) Except for units subject to paragraph (c)(6), any owner or operator of units subject to this rule shall perform diagnostic emission checks of NOx emissions with a portable NOx, CO, and oxygen analyzer according to the Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Units Subject to South Coast Air Quality Management District Rules 1146 and 1146.1 according to the following schedule:

(A) The owner or operator of units subject to paragraphs (c)(1), (c)(3), or (c)(4) shall check NOx emissions at least monthly or every 750 unit operating hours, whichever occurs later. If a unit is in compliance for three consecutive diagnostic emission checks, without any adjustments to the oxygen sensor set points, then the unit may be checked quarterly or every 2,000 unit operating hours, whichever occurs later, until the resulting diagnostic emission check exceeds the applicable limit specified in paragraphs (c)(1)or (c)(3).

(C) Records of all monitoring data required under subparagraphs (d)(8)(A) and (d)(8)(B) shall be maintained for a rolling twelve month period of two years (5 years for Title V facilities) and shall be made available to District personnel upon request.

(D) The portable analyzer diagnostic emission checks required under subparagraph (d)(8)(A) and (d)(8)(B) shall only be conducted by a person who has completed an appropriate District-approved training program in the operation of portable analyzers and has received a certification issued by the District.

Analysis:
Rule 1100—Implementation Schedule for NOx Facilities provides clarifying applicability requirements for Rule 1146, as follows:

(e) The applicable monitoring, reporting, and recordkeeping requirements are as follows:

(1) For Title V facilities, an owner or operator of a RECLAIM facility shall comply with the monitoring, reporting, and recordkeeping requirements specified in Rule 2012.

Therefore, Rule 1100(e)(1) requires the NOx monitoring to meet Rule 2012. As a major NOx source, the boiler will be required to be equipped with a certified CEMS to meet RECLAIM requirements, which supersede the above Rule 1146(d)(6), (d)(7), and (d)(8) requirements.

(9) An owner or operator shall comply with the requirements as applied to CO emissions specified in paragraph (d)(8) and subparagraph:
(A) (d)(6)(A) for units greater than or equal to 10 million Btu per hour [source testing every three years],

Analysis:
First, paragraph (d)(9) requires compliance with paragraph (d)(8) as applies to CO. Paragraph (d)(8) starts out by exempting "units subject to paragraph (c)(6)" from diagnostic emission checks of NOx emissions with a portable NOx, CO, and oxygen analyzer. Paragraph (c)(6) requires any unit(s) with a rated heat input capacity greater than or equal to 40 MMBtu/hr to be equipped with a continuous in-stack nitrogen oxides monitor or equivalent verification system in compliance with Rule 218, Rule 218.1, and 40 CFR Part 60 Appendix B Specification 2. As AES has opted to install a CO CEMS for the auxiliary boiler, the boiler will be a "unit subject to paragraph (c)(6)" for CO. As such, the boiler will be exempt from portable analyzer testing for CO.

Second, subparagraph (d)(9)(A) requires compliance with (d)(6)(A) as applies to CO. Subparagraph (d)(6)(A) requires source testing every three years. Subparagraph (d)(7)(A), however, allows the option of using periodic monitoring or testing as required in a Title V permit, or relative accuracy testing for continuous emissions monitoring verification pursuant to Rule 218.1 or 40 CFR Part 60 Appendix B Specification 2.

Condition H23.7 currently requires CO to meet the applicable requirements of Rule 1146. The condition also states: "These requirement shall include applicable portable analyzer testing and source testing requirements." In accordance with the requirements of paragraph (d)(9) discussed above, the condition will be updated, as a result of the installation of the CO CEMS, to remove the condition that the requirements shall include applicable portable analyzer testing and source testing requirements.

Also, condition H23.7 will be revised to require compliance with the applicable requirements of Rules 1146 and 1100 for NOx.

Condition D29.6 requiring periodic source testing for CO will be deleted because subparagraph (d)(7)(A) allows periodic source testing **or** continuous emissions monitoring verification such as RATA tests for the CO CEMS. Condition K40.5—The reference to condition D29.6 will be removed because that condition will be deleted.

(e) Compliance Schedule

(1) The owner or operator of any unit(s) at a RECLAIM or former RECLAIM facility subject to paragraph (c)(1) shall meet the applicable NOx emission limit in Table 1146-1 in accordance with the schedule specified in *Rule 1100 – Implementation Schedule for NOx Facilities.*

Analysis:
See Rule 1100 analysis below.

Rule 1100 – Implementation Schedule for NOx Facilities, adopted 12/7/18

(a) Purpose

The purpose of this rule is to establish the implementation schedule for Regulation XX NOx RECLAIM facilities that are transitioning to a command-and-control regulatory structure.

(b) Applicability

This rule applies to any owner or operator of a RECLAIM or former RECLAIM facility that owns or operates equipment that meets the applicability provisions specified in:

(1) Rule 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters;

Analysis:
This rule is applicable to AES because the AEC is a RECLAIM facility, and the auxiliary boiler is subject to Rule 1146.

(d) Rule 1146 and Rule 1146.1 Implementation Schedule

(1) An owner or operator of a RECLAIM or former RECLAIM facility with any Rule 1146 or Rule 1146.1 unit shall:

(A) On or before December 7, 2019, submit complete SCAQMD permit applications for any Rule 1146 and Rule 1146.1 units that currently do not meet the applicable NOx concentration limit specified in paragraph (d)(3);

(B) On or before January 1, 2021 meet the applicable NOx concentration limit for a minimum of 75% of the cumulative total rated heat input capacity of all Rule 1146 and Rule 1146.1 units at the facility;

Analysis:
The auxiliary boiler is expected to meet the NOx limit of 5 ppmvd at 3% O2 in subparagraph (c)(1)(I). The auxiliary boiler is a watertube boiler with a NOx limit of 5 ppmvd at 3% O_2, as required by the Permit to Construct issued on 4/18/17. The 5 ppmvd NOx limit was imposed as a result of the top-down PSD BACT analysis performed for Rule 1703(a)(2)-PSD-BACT in the FDOC. Condition A195.13 specifies the NOx limit is 5.0 ppmvd, and condition D29.5 requires an initial source test. The boiler is in the process of being installed.

(3) The applicable NOx concentration limits specified in subparagraphs (d)(1)(B) and (d)(1)(C) are as follows:

(A) Rule 1146 units shall meet the NOx concentration limit for the category of equipment specified in Rule 1146, Table 1146-1 – NOx Emission Limits and Compliance Schedule;
(B) Rule 1146 units that meet the applicability provisions specified in Rule 1146 paragraph (c)(2) shall meet the ammonia emission limit specified in Rule 1146 paragraph (c)(2);

Analysis:
The auxiliary boiler and SCR will be in compliance with NOx and NH_3 limits referenced above. Condition A195.13 specifies the NOx limit is 5.0 ppmvd at 3% O2. Condition A195.16 specifies the NH_3 limit is 5 ppmvd at 3% O_2.

(e) The applicable monitoring, reporting, and recordkeeping requirements are as follows:
(1) For Title V facilities, an owner or operator of a RECLAIM facility shall comply with the monitoring, reporting, and recordkeeping requirements specified in Rule 2012.

(2) Except for Title V facilities, the owner or operator of a RECLAIM facility that becomes a former RECLAIM facility shall comply with the monitoring, reporting, and recordkeeping requirements in the applicable rule(s) as specified in subdivision (b) upon the date the facility becomes a former RECLAIM facility.

Analysis:
As the AEC is Title V and RECLAIM, the auxiliary boiler will be required to meet the monitoring, reporting, and recordkeeping requirements specified in Rule 2012.

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REGULATION XIII—NEW SOURCE REVIEW (NSR)

The South Coast AQMD new source review rules are based on both the National Ambient Air Quality Standards (NAAQS) and the California Ambient Air Quality Standards (CAAQS). The primary NAAQS are the levels of air quality necessary, with an adequate margin of safety, to protect the public health.

- ***Rule 1303(a)(1)—BACT/LAER (PM_{10}, SOx, VOC, CO)***
- ***Rule 2005(c)(1)(A)—BACT/LAER (NOx)***

  Rule 1303(a)(1) requires Best Available Control Technology (BACT) for a new or modified source which results in an emission increase of any nonattainment air contaminant, any ozone depleting compound, or ammonia, with the South Coast AQMD interpreting the emission increase to be 1 lb/day or greater of uncontrolled emissions.

  The South Coast AQMD is not in attainment for PM_{10} (California 24-hr and annual standards) and ozone, but is in attainment for PM_{10} (national 24-hr standard), CO, NOx, and SOx. Since NOx, SOx, and VOC (no attainment standards for VOC) are precursors to non-attainment pollutants, they are treated as non-attainment pollutants as well. Specifically, NOx and VOC are precursors to ozone. NOx and SOx are precursors to PM_{10} and $PM_{2.5}$. Thus, this rule requires BACT for NOx (non-RECLAIM), PM_{10}, SOx, VOC, and ammonia. As discussed below, Rules 1701(b)(1) and 1703(a)(2) require BACT for CO. Rule 2005(c)(1)(B) requires BACT for NOx for RECLAIM facilities.

  Rule 1303(a)(2) provides that BACT for sources located at major polluting facilities shall be at least as stringent as Lowest Achievable Emissions Rate (LAER) as defined in the federal Clean Air Act Section 171(3). Rule 1302(s) (as amended 11/4/16) defines a "major polluting facility" (same as major stationary source) located in the South Coast Air Basin as any facility which emits, or has the potential to emit, a criteria air pollutant at a level that equals or exceeds the following emission thresholds: (1) VOC, 10 tpy; (2) NOx, 10 tpy; (3) SOx, 70 tpy; (4) CO, 50 tpy; and (5) PM_{10}, 70 tpy. If a threshold for any one criteria pollutant is equaled or exceeded, the facility is a major polluting facility, and will be subject to LAER for all pollutants subject to NSR. The AGS is a major polluting facility because *Table 13* indicates the PTEs for VOC (453.72 tpy), NOx (635.60 tpy), CO (21,871.86 tpy), and PM_{10} (627 tpy) exceed the applicable thresholds.

  Rule 1302(h) defines BACT as "the most stringent emission limitation or control technique which:

  (1) has been achieved in practice [AIP] for such category or class of source; or

  (2) is contained in any state implementation plan (SIP) approved by the US EPA approved by the United States Environmental Protection Agency (EPA) for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer or designee that such limitation or control technique is not presently achievable; or

(3) is any other emission limitation or control technique, found by the Executive Officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures as listed in the Air Quality Management Plan (AQMP) or rules adopted by the District Governing Board."

The first two requirements in the BACT definition above are required by federal law as LAER for major sources. The third part of the definition is unique to South Coast AQMD and some other areas in California, and allows for more stringent controls than LAER. For major polluting facilities, LAER is determined on a permit-by-permit basis.

5. **A/N 604014—Auxiliary Boiler (A/N 579158)**
6. **A/N 613323—Selective Catalytic Reduction for Auxiliary Boiler (A/N 579166)**

- **FDOC Summary, A/N 579158 & 579166**

  The FDOC provided a New Source Review BACT/LAER analyses for VOC, SO_2, and NH_3 which are not PSD pollutants for the proposed facility. As required by PSD, top-down BACT analyses were performed under Rule 1703(a)(2) for NOx, PM_{10}, and CO below.

  Normal Operations

  - *BACT/LAER for VOC Emissions*

    VOCs are formed during the combustion process as a result of incomplete combustion of the carbon present in the fuel. The commercially available control measures that are identified in the most-stringent BACT determinations are use of low-sulfur, pipeline quality natural gas and good combustion practice to ensure complete combustion. The analysis concluded this is BACT/LAER for VOC for the auxiliary boiler.

    BACT/LAER for SO_2 Emissions

    Emissions of SOx are dependent on the sulfur content in the fuel rather than any combustion variables. During the combustion process, almost all of the sulfur in the fuel is oxidized to SO_2. The AEC will be supplied with natural gas from the Southern California Gas pipeline, which is limited by Tariff Rule No. 30 to a maximum total fuel sulfur content of less than 0.75 grain of sulfur per 100 scf. The analysis concluded that the use of pipeline-quality natural gas with low sulfur content is BACT/LAER for SO_2.

  - *BACT/LAER for Ammonia Emissions*

    A very small amount of ammonia used in the SCR systems to control NOx from the turbine exhaust stream is not consumed by the reaction in the SCR systems. The

analysis concluded that a limit of 5 ppmvd at 15% O_2 (1-hr averaging) is BACT/LAER for the ammonia slip.

Commissioning, Startups and Shutdowns

Condition nos. A195.13 and A195.14 provide that the BACT limits of 5.0 ppmvd NOx and 50.0 ppmvd CO, respectively, shall not apply during commissioning and startup periods.

During commissioning, it is not technically feasible for the auxiliary boiler to meet the BACT limits for NOx and CO during the entire period. The emissions are only partially abated as the operation of the low NOx burner, FGR and SCR catalyst are optimized. To limit the duration of the commissioning period during which BACT is not achievable, condition no. E193.10 limits the commissioning period to 30 hours of fired operation.

During startups, it is not technically feasible for the auxiliary boiler to meet the BACT limits for NOx and CO during the entire startup. The SCR that is used to achieve the required emissions reduction for NOx is not fully effective when the surface of the catalyst is below the manufacturers' recommended operating range. Further, the low NOx burner, FGR and other combustion components require the startup period to become fully functional. Condition C1.7 specifies limits for cold, warm, and hot startups. The startup limits include: (1) number of cold starts per calendar month and year; (2) number of warm starts per calendar month and year; (3) number of hot starts per calendar month and year; (4) number of starts per day; (5) duration of cold starts, warm starts, and hot starts; and (6) NOx emissions per cold start, warm start, and hot start.

- **A/N 604014 & 613323—Condition Changes**

  Normal Operations

  As emissions will not increase, a BACT/LAER analysis is not required.

  Commissioning, Startups and Shutdowns

  Condition no. E193.10 will be revised to limits the commissioning period to ~~30~~ **100** hours of fired operation.

- ***Rule 1303(b)(1)—Modeling***

  The Executive Officer or designee shall, except as Rule 1304 applies, deny the Permit to Construct for any new or modified source which results in a net emission increase of any nonattainment air contaminant at a facility, unless the applicant substantiates with air dispersion modeling that the new facility or modification will not cause a violation, or make significantly worse an existing violation according to Appendix A of the rule, or other analysis approved by the Executive Officer

or designee, of any state or national ambient air quality standards at any receptor location in the South Coast AQMD. As discussed for the BACT/LAER requirements above, the South Coast AQMD is not in attainment for PM_{10} (California 24-hr and annual standards) and ozone, but is in attainment for PM_{10} (national 24-hr standard), CO, NOx, and SOx. Since NOx, SOx, and VOC (no attainment standards for VOC) are precursors to non-attainment pollutants, they are treated as non-attainment pollutants as well.

Rule 1303 requires modeling for NO_2 (non-RECLAIM), CO, PM_{10}, and SO_2. Rule 2005(c)(1)(B) requires modeling for NO_2 for RECLAIM facilities. (The standards in Appendix A are outdated. The modeling analyses below are based on current ambient air quality standards.)

Compliance determination is different for attainment and nonattainment pollutants. For attainment pollutants, NO_2, CO, SO_2, PM_{10} (federal standard), the modeled peak impacts plus the worst-case background concentrations shall not exceed the most stringent air quality standard. For non-attainment pollutants where the background concentrations exceed the ambient air quality standards, the modeled peak impacts shall not cause an exceedance of the Rule 1303 significant change thresholds. The South Coast Air Basin is designated non-attainment for the state PM_{10} standard, and state and federal $PM_{2.5}$ standards.

Rule 1304(a) provides an exemption from the modeling requirements of Rule 1303(b)(1) and the offset requirement of Rule 1303(b)(2) for:

(2) Electric Utility Steam Boiler Replacement
The source is replacement of electric utility steam boiler(s) with combined cycle gas turbine(s), intercooled, chemically-recuperated gas turbines, other advanced gas turbine(s); solar, geothermal, or wind energy or other equipment, to the extent that such equipment will allow compliance with Rule 1135 or Regulation XX rules. The new equipment must have a maximum electrical power rating (in megawatts) that does not allow basin wide electricity generating capacity on a per-utility basis to increase. If there is an increase in basin-wide capacity, only the increased capacity must be offset.

Analysis:

The combined- and simple-cycle turbines, but not the auxiliary boiler, are exempt from the modeling requirements of Rule 1303 (CO, PM_{10}, SO_2).

The **FDOC** provided a modeling analysis for the normal operation of the auxiliary boiler that demonstrated compliance with the ambient air quality standards for Rule 1303 (CO, PM_{10}, SO_2) and Rule 2005 (NO_2), as set forth in *Table 57A - Modeled Results - Normal Operation for Auxiliary Boiler*. The FDOC also provided a modeling analysis for the simultaneous commissioning of the two combined-cycle turbine with the auxiliary boiler in normal operation that demonstrated compliance with the ambient air quality standards, as set forth in *Table 59 - Modeled Results – Commissioning for AEC CCGT (Auxiliary Boiler in Normal Operation)*. A

separate modeling analysis for the boiler commissioning was not required because the impacts of the equivalent of two startups per day (6 hours/day) for five days would be minor. The FDOC also provided facility-wide modeling for the normal operation of the two combined-cycle turbines, four simple-cycle turbines, and the auxiliary boiler in *Table 57 - Modeled Results - Normal Operation for Total Project*, in support of the CEC's analysis of the *Supplemental Application for Certification*, submitted on 10/26/15.

For **A/N 604014 & 613323** under evaluation here, the commissioning duration will increase from 30 hr to 100 hrs. For the FDOC, modeling for the commissioning period was not required because the impacts of the equivalent of two startups per day (6 hr/day) for 5 days (30 hours) would be minor. For these applications, impacts for the increase to 100 hours spread over three months will continue to be minor.

For the **Application** (A/N 604015, 604018, 604020**,** 608431-608433**,** 610354-610360) under evaluation in a separate engineering evaluation, the facility-wide modeling for the normal operation of the two combined-cycle turbines, four simple-cycle turbines, and the auxiliary boiler (no change in emissions) will be revised for the annual averaging period in *Table 57 - Modeled Results - Normal Operation for Total Project*, in support of the CEC's analysis of the *Petition for Post-Certification Amendment*. The Application proposes to increase the annual operating hours and emissions for the combined-cycle turbines, and decrease the annual operating hours and emissions for the simple-cycle turbines.

- ***Rule 1303(b)(2)—Offsets***

Rule 1303(b)(2) requires a net emission increase in emissions of any nonattainment air contaminant (PM_{10}, ROG, and SOx) from a new or modified source to be offset unless exempt from offset requirements pursuant to Rule 1304. Since CO is an attainment pollutant and not a precursor to any nonattainment pollutant, offset requirements are not applicable.

"Source" is defined by Rule 1302(ao) to mean "any permitted individual unit, piece of equipment, article, machine, process, contrivance, or combination thereof, which may emit or control an air contaminant. This includes any permit unit at any non-RECLAIM facility and any device at a RECLAIM facility."

Unless exempt, the amount of offsets required for each pollutant is determined using the 30-day average. The 30-day average is based on the highest emissions for any month, including a month where commissioning takes place. The offset ratio for emission reduction credits (ERCs) is 1.2-to-1.

Analysis:

Rule 1304(d)(2)(B) specifies that any modified facility that has a post-modification potential equal to or more than 4 tpy VOC, 4 tpy SOx, and 4 tpy PM_{10} is required to provide offsets for

the emissions increases. **Offsets are not required for the auxiliary boiler because the condition changes will not increase emissions.** AES has indicated that the monthly emission limits in current condition A63.4 are sufficient for the increased commissioning period of 100 hours.

- ***Rule 1303(b)(4)-Facility Compliance***
  AEC will comply with all applicable rules and regulations of the South Coast AQMD, as required by this rule.

- ***Rule 1303(b)(5)-Major Polluting Facilities***
- ***Rule 2005(g)—Additional Federal Requirements for Major Stationary Sources***
  Any major modification at an existing major polluting facility shall comply with the following provisions. AGS is an existing major polluting facility as defined by Rule 1302(s). However, the condition changes for the auxiliary boiler and SCR, without an increase in emissions, do not constitute a major modification under Rule 1302(r). Therefore, these provisions are not applicable.

Rule 1313—Permits to Operate

*The **FDOC** provided the following analysis. For **A/N 604014 & 613323** under evaluation here, the analysis remains the same as for the FDOC because the condition changes for the auxiliary boiler and SCR will not change emissions.*

Section (d) is applicable to the retirement plan.

(d) For a new source or modification which will be a replacement, in whole or part, for an existing source on the same or contiguous property, a maximum of 90 days may be allowed as a start-up period for simultaneous operation of the subject sources.

Analysis: Condition no. F52.1 limits simultaneous operation to 90 days, and sets forth a number of requirements for the retirement plan and the retirement of the AGS Boilers.

(g) Emission Limitation Permit Conditions
Every permit shall have the following conditions:

(1) Identified BACT conditions
(2) Monthly maximum emissions from the permitted source

Analysis:

Auxiliary Boiler

BACT-- Condition nos. A195.13 and A195.14 set forth the BACT limits for NOx and CO, respectively.

Monthly Emissions--Condition no. A63.4 sets forth the monthly limits for CO, VOC, PM_{10}, and SOx. These limits indirectly limit NOx.

Rule 1325—Federal PM2.5 New Source Review Program, as amended 1/4/19

Rule 1325 was adopted on June 3, 2011 to incorporate U.S. EPA requirements for PM2.5 into Regulation XIII – New Source Review (NSR). The rule mirrors federal requirements, including offset ratios, Lowest Achievable Emission Rate (LAER) compliance, and control of PM2.5 precursors.

Rule 1325 was amended on 12/5/14 to incorporate administrative changes to definitions, provisions and exclusions, based on comments received from the U.S. EPA regarding SIP approvability of Rule 1325. The amended rule was approved into the California State Implementation Plan on 5/1/15. The applicable requirements of 40 CFR Part 51, Appendix S, were necessary for permitting actions until Rule 1325 became SIP-approved.

Rule 1325 was amended on 11/4/16 to establish appropriate major stationary source thresholds for direct $PM_{2.5}$ and $PM_{2.5}$ precursors, including VOC and ammonia, in order to align with the recent reclassification of the South Coast Basin from a "moderate" $PM_{2.5}$ nonattainment area to a "serious" nonattainment area and with U.S. EPA's Fine Particulate Matter National Ambient Air Quality Standards implementation rule. The amendments were intended to facilitate SIP approval of the regulations. The amendment added ammonia and VOC as precursors to $PM_{2.5}$, per Clean Air Act Subpart 4 requirements. The major polluting facility thresholds were lowered from 100 tons per year per pollutant to 70 tons per year per pollutant. These amendments will be effective after August 14, 2017 or upon the effective date of EPA's approval of these amendments to this rule, whichever is later. US EPA's Fine Particulate Matter National Ambient Air Quality Standards implementation rule states an area can rely on SIP-approved $PM_{2.5}$ New Source Review rule until the new rule is approved. 81 Fed Reg 58009 (August 24, 2016). US EPA's final implementation rule became effective on 10/24/16.

Rule 1325 was amended on 1/4/19 to address a deficiency in the 11/4/16 amendment in which the definition of "precursors" was expanded to add VOC and ammonia (NH3) to the existing list of PM2.5 precursors (oxides of nitrogen and sulfur dioxide), but the definition of "regulated NSR pollutant" was not expanded to explicitly reference VOC and NH3. The 1/4/19 amendment addresses the deficiency by referencing "precursors" in the definition of "regulated NSR pollutant." In addition, the rule language was clarified and outdated language removed.

The relevant provisions of Rule 1325, as amended 1/4/19, are presented below, followed by the rule analysis.

(a) This rule applies to any new major polluting facility, major modifications to a major polluting facility, and any modification to an existing facility that would constitute a major polluting facility in and of itself that will emit PM2.5 or its precursors, as defined herein;

located in areas federally designated pursuant to Title 40 of the Code of Federal Regulations (40 CFR) 81.305 as non-attainment for $PM_{2.5.}$

With respect to major modifications, this rule applies on a pollutant-specific basis to emissions of $PM_{2.5}$ and its precursors, for which (1) the source is major, (2) the modification results in a significant increase, and (3) the modification results in a significant net emissions increase.

(b) Definitions

For the purposes of this rule, the definitions in Title 40 CFR 51.165(a)(1), as it exists on November 4, 2016 shall apply, unless the same term is defined below, then the defined term below shall apply:

(1) BASELINE ACTUAL EMISSIONS means the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with the following:

(A) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The Executive Officer shall allow the use of a different time period upon a determination that it is more representative of normal source operation….

(3) MAJOR MODIFICATION means:

(A) Any physical change in or change in the method of operation of a major polluting facility that would result in: a significant emissions increase of a regulated NSR pollutant; and a significant net emissions increase of that pollutant from the major polluting facility.

(4) MAJOR POLLUTING FACILITY means, on a pollutant specific basis, any emissions source located in areas federally designated pursuant to 40 CFR 81.305 as non-attainment for $PM_{2.5}$, including the South Coast Air Basin (SOCAB) which has actual emissions of, or the potential to emit $PM_{2.5}$, or its precursors at or above 70 tons per year per pollutant. A facility is considered to be a major polluting facility only for the specific pollutant(s) with a potential to emit at or above the levels specified.

(9) PRECURSORS mean, for the purposes of this rule, NOx, sulfur dioxide (SO_2), volatile organic compounds (VOC), and ammonia (NH3).

(13) SIGNIFICANT means, in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:

Pollutant	Emissions Rate (tons per year)
NOx	40
SO2	40
VOC	40
NH3	40
PM2.5	10

(c) Requirements

(1) The Executive Officer shall deny the Permit for a new major polluting facility; or major modification to a major polluting facility; or any modification to an existing facility that would constitute a major polluting facility in and of itself, unless each of the following requirements is met:

(A) Lowest Achievable Emission Rate (LAER**)** is employed for the new or relocated source or for the actual modification to an existing source; and

(B) Emission increases shall be offset at an offset ratio of 1.1:1 for $PM_{2.5}$ and the ratio required in Regulation XIII or Rule 2005 for NOx and SO_2 as applicable; and

(C) Certification is provided by the owner/operator that all major sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by such person (or by any entity controlling, controlled by, or under common control with such person) in the State of California are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act; and

(D) An analysis is conducted of alternative sites, sizes, production processes, and environmental control techniques for such proposed source and demonstration made that the benefits of the proposed project outweigh the environmental and social costs associated with that project.

(h) Test Methods

For the purpose of this rule only, testing for point sources of $PM_{2.5}$ shall be in accordance with U.S. EPA Test Methods 201A and 202.

Analysis:

The **FDOC** provided an analysis for Rule 1325, amended 11/4/16, for the AEC.

For **A/N 604014 & 613323** under evaluation here**,** the condition changes for the auxiliary boiler and SCR will not change emissions. Therefore, a Rule 1325 analysis is not required, except that condition F2.1 limit for $PM_{2.5}$ will be updated from the current 100 tpy to 70 tpy pursuant to paragraph (b)(4). A complete analysis for Rule 1325 analysis, amended 1/4/19, will be performed in the separate evaluation for the **Application,** see below.

The **Application** (A/N 604015, 604018, 604020**,** 608431-608433**,** 610354-610360), under evaluation in a separate engineering evaluation, proposes to increase the annual operating hours and emissions for the combined-cycle turbines and decrease the annual operating hours and emissions for the simple-cycle turbines. An analysis of Rule 1325, as amended 1/4/19, will be performed.

Rule 1401—New Source Review of Toxic Air Contaminants, as amended 9/1/17
Rule 2005(i) – RECLAIM Rule 1401 Compliance, as amended 12/4/15

Rule 1401 specifies limits for maximum individual cancer risk (MICR), cancer burden, and noncancer acute and chronic hazard index (HI) from new permit units, relocations or modifications to existing permit units that emit toxic air contaminants listed in Table I of this rule. The rule establishes allowable risks for permit units requiring new permits pursuant to Rules 201 or 203. Rule 2005(i) requires compliance with Rule 1401 for NOx emissions at RECLAIM facilities.

Because the allowable risks are for each permit unit, the limits are for each turbine and the auxiliary boiler. The relevant requirements are presented below.

(d) Requirements
The Executive Officer shall deny the permit to construct a new, relocated or modified permit unit if emissions of any toxic air contaminant listed in Table I may occur, unless the applicant has substantiated to the satisfaction of the Executive Officer all of the following:

(1) MICR and Cancer Burden
The cumulative increase in MICR which is the sum of the calculated MICR values for all toxic air contaminants emitted from the new, relocated or modified permit unit will not result in any of the following:
(A) an increased MICR greater than one in one million ($1.0 \times 10^{-6)}$ at any receptor location, if the permit unit is constructed without T-BACT;
(B) an increased MICR greater than ten in one million (10×10^{-6}) at any receptor location, if the permit unit is constructed with T-BACT;
(C) a cancer burden greater than 0.5.

(2) Chronic Hazard Index
The cumulative increase in total chronic HI for any target organ system due to total emissions from the new, relocated or modified permit unit owned or operated by the applicant for which applications were deemed complete on or after the date when the

risk value for the compound is finalized by the state Office of Environmental Health Hazard Assessment (OEHHA) will not exceed 1.0 at any receptor location.

(3) Acute Hazard Index
The cumulative increase in total acute HI for any target organ system due to total emissions from the new, relocated or modified permit unit owned or operated by the applicant for which applications were deemed complete on or after the date when the risk value for the compound is finalized by OEHHA will not exceed 1.0 at any receptor location.

(e) Risk Assessment Procedures
(1) The Executive Officer shall periodically publish procedures for determining health risk assessments under this rule. To the extent possible, the procedures will be consistent with the most recently adopted policies and procedures of the state OEHHA.

(f) Emissions Calculations
(3) For the purpose of determining MICR, cancer burden and chronic HI due to a modified permit unit pursuant to this rule, the increase in emissions from the modified permit unit shall be calculated based on the difference between the total permitted emissions after the modification, calculated pursuant to the criteria established in subparagraphs (f)(1)(A), (B), (C), and (D), and: ….

On March 6, 2015, the California Office of Environmental Health Hazard Assessment (OEHHA) approved the Air Toxics Hot Spots Program Guidance Manual for Preparation of Risk Assessments (2015 OEHHA Guidelines). On June 5, 2015, the South Coast AQMD approved amendments to Rule 1401 to revise definitions and risk assessment procedures to be consistent with the 2015 OEHHA Guidelines. These updated guidelines take into account recent scientific advances which have found greater risk to children when they are exposed to cancer causing compounds.

Analysis:
The **FDOC** provided an HRA for the auxiliary boiler for the South Coast AQMD evaluation. In addition, the FDOC provided an HRA for the entire project in support of the CEC's analysis of the *Supplemental Application for Certification*. The facility-wide HRA included the operation of the two combined-cycle turbines, four simple-cycle turbines, and the auxiliary boiler.

For **A/N 604014 & 613323** under evaluation here**,** the HRA for the auxiliary boiler and SCR is not required to be revised because the condition changes will not change emissions.

The **Application** (A/N 604015, 604018, 604020**,** 608431-608433**,** 610354-610360), under evaluation in a separate engineering evaluation, proposes to increase the annual operating hours and emissions for the combined-cycle turbines and decrease the annual operating hours and emissions for the simple-cycle turbines. The facility-wide HRA for the two combined-cycle

turbines, four simple-cycle turbines, and the auxiliary boiler (no change in emissions) will be revised for the annual averaging period in support of the CEC's analysis of the *Petition for Post-Certification Amendment*.

REGULATION XVII – PREVENTION OF SIGNIFICANT DETERIORATION

The federal Prevention of Significant Deterioration (PSD) has been established to protect deterioration of air quality in those areas that already meet the primary NAAQS. This regulation sets forth preconstruction review requirements for stationary sources to ensure that air quality in clean air areas do not significantly deteriorate while maintaining a margin for future industrial growth. Specifically, the PSD program establishes allowable concentration increases for attainment pollutants due to new or modified emission sources that are classified as major stationary sources.

Effective upon delegation by EPA, this regulation shall apply to preconstruction review of stationary sources that emit attainment air contaminants. On 3/3/03, EPA rescinded its delegation of authority to the South Coast AQMD. On 7/25/07, the EPA and South Coast AQMD signed a new "Partial PSD Delegation Agreement." The agreement is intended to delegate the authority and responsibility to the South Coast AQMD for issuance of initial PSD permits and for PSD permit modifications where the applicant does not seek to use the emissions calculation methodologies promulgated in 40 CFR 52.21 (NSR Reform) but not included in South Coast AQMD Regulation XVII. The Partial Delegation agreement did not delegate authority and responsibility to South Coast AQMD to issue new or modified PSD permits based on Plant-wide Applicability Limits (PALS) provisions of 40 CFR 52.21.

Since this is a partial delegation the facilities in the South Coast Air Basin (SCAB) may either apply directly to EPA for the PSD permit in accordance with the current requirements of 40 CFR Part 52 Subpart 21, or apply to the South Coast AQMD in accordance with the current requirements of Regulation XVII. AES has opted to apply to the South Coast AQMD.

The SCAB has been in attainment for NO_2, SO_2, and CO emissions. In addition, effective 7/26/13, the SCAB has been redesignated to attainment for the 24-hour PM_{10} national ambient air quality standard. Therefore, this regulation applies to these emissions.

- ***RULES 1701, 1702, 1706--PSD APPLICABILITY***

  The relevant PSD applicability rule sections are presented below, followed by the applicability analysis.

  Rule 1701(b) Applicability

  Effective upon delegation by EPA, this regulation shall apply to preconstruction review of stationary sources that emit attainment air contaminants.

  - ***Rule 1701(b)(1)*** provides: The BACT requirement applies to a net emission increase of a criteria air contaminant from a permit unit at any stationary source.

- ***Rule 1701(b)(2)*** provides:
  All of the requirements of this regulation apply, except as exempted in Rule 1704, to the following stationary sources:

  (A) A new source or modification at an existing source where the increase in potential to emit is at least 100 or 250 tons of attainment air contaminants per year, depending on the source category; or

  (B) A significant emission increase at an existing major stationary source; or

  (C) Any net emission increase at a major stationary source located within 10 km of a Class I area, if the emission increase would impact the Class I area by 1.0 $\mu g/m^3$, (24-hours average).

- ***Rule 1702*** provides definitions.

  (e) Best Available Control Technology (BACT) means the most stringent emission limitation or control technique which:
  - (1) has been achieved in practice for such permit unit category or class of source. For permit units not located at a major stationary source, a specific limitation or control technique shall not apply if the owner or operator of the proposed sources demonstrates to the satisfaction of the Executive Officer that such limitation or control technique is not attainable for that permit unit; or
  - (2) is contained in any State Implementation Plan (SIP) approved by the Environmental Protection Agency (EPA) for such permit unit category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer that such limitation or control technique is not presently achievable; or
  - (3) is any other emission control technique, including process and equipment changes of basic and control equipment, found by the Executive Officer to be technologically feasible and cost-effective for such class or category of sources or for a specific source….

  (m) "Major Stationary Source" means: "one of the following source categories: (1) Fossil fuel-fired steam electric plants of more than 250 million BTU/hr input…; which emits or has the potential to emit 100 tons per year or more of any contaminant regulated by the Act; or (2) an unlisted stationary source that emits or has the potential to emit 250 tons per year or more of any pollutant regulated by the Act; or (3) a physical change in a stationary source not otherwise qualifying under

paragraph (1) or (2) if a modification would constitute a major stationary source by itself.

(s) Significant Emission Increase means any attainment air contaminant for which the net cumulative emission increase of that air contaminant from a major stationary source is greater than the amount specified as follows:

Contaminant	Emissions Rate (tpy)
Carbon Monoxide	100
Sulfur Dioxide	40
Nitrogen Oxides	40
PM_{10}	15

- ***Rule 1706*** shall be used as the basis for calculating applicability to Regulation XVII as delineated in Rule 1703(a). **Rule 1706(c)** provides the emissions calculation methodology for determining a net emission increase.

(1)(A) The emissions for new permit units shall be calculated as the potentials to emit.

(1)(B) The emissions for removal from service shall be calculated from:

(i) the sum of actual emissions, as determined from company records, which have occurred during the two-year period immediately preceding date of permit application, or a different two year time period within the past five (5) years upon a determination by the Executive Officer that it is more representative of normal source operation, except annual emission declarations pursuant to Rule 301 may be used if less than the actual emissions as determined above; and

(ii) the total emissions in those two years shall be calculated on an annual basis.

- ***RULE 1703—PSD REQUIREMENTS***

(a)(2) Each permit unit is constructed using BACT for each criteria air contaminant for which there is a net emission increase;

(a)(3) For each significant emission increase of an attainment air contaminant at a major stationary source:

(B) The new source or modification will be constructed using BACT.

(C) The applicant has substantiated by modeling that the proposed source or modification, in conjunction with all other applicable emission increases or reductions (including secondary emissions) affecting the impact area, will not cause or contribute to a violation of:

(i) Any National or State Ambient Air Quality Standard in any air quality control region; or

(ii) Any applicable maximum allowable increase over the baseline concentration in any area.

(D) The applicant conducts an analysis of the ambient air quality in the impact area the new or modified stationary source would affect…. The applicant may rely on existing continuous monitoring data collected by the District if approved by the Executive Office…;

Analysis:

The South Coast AQMD is presently in attainment for the primary NAAQS for NOx, CO, SOx, and PM_{10}. For proposed modifications at existing major sources, PSD applies to each regulated pollutant for which the proposed emissions increase resulting from the modification both is significant and results in a significant net emissions increase.

The **FDOC** determined that NOx and PM_{10} were subject to PSD review for all PSD requirements. CO was not subject to PSD requirements other than BACT, but was evaluated for all PSD requirements for completeness. SO_2 was not subject to PSD requirements other than BACT. As required by Rules 1701(b)(1) and 1703(a)(2), top-down BACT analyses for NOx, PM_{10}, and CO were performed for the auxiliary boiler. BACT requirements were determined to be 5.0 ppmvd (1-hr average) for NOx, pipeline-quality natural gas with low sulfur and good combustion practice for $PM_{10,}$ and 50.0 ppmvd (1-hr average) for CO. The analysis also included facility-wide PSD modeling for the two combined-cycle turbines, four simple-cycle turbines, and the auxiliary boiler.

For **A/N 604014 & 613323** under evaluation here, BACT for the auxiliary boiler and SCR and facility-wide PSD modeling are not required to be re-evaluated because the condition changes will not increase emissions.

The **Application** (A/N 604015, 604018, 604020**,** 608431-608433**,** 610354-610360), under evaluation in a separate engineering evaluation, proposes to increase the annual operating hours and emissions for the combined-cycle turbines and decrease the annual operating hours and emissions for the simple-cycle turbines. The facility-wide PSD modeling for the two combined-cycle turbines, four simple-cycle turbines, and the auxiliary boiler (no change in emissions) will be revised for the annual averaging period in support of the CEC's analysis of the *Petition for Post-Certification Amendment*. The tables that will be revised are (1) *Table 82 – Maximum Modeled Project Impacts Compared to Class II SILs and PSD Increment*

Standards, (2) *Table 84 – Maximum Modeled Impacts Compared to Class I SIL*, and (3) *Table 85 - Model Results – Normal Operation for AEC - Compliance with Secondary NAAQS.*

Rule 1714 – Prevention of Significant Deterioration for Greenhouse Gases, as amended 3/1/19

Rule 1714, adopted 11/5/10, was adopted into the SIP on 12/10/12, and became effective on 1/9/13. Upon the effective date, the South Coast AQMD became the Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permitting authority for sources located within the South Coast AQMD.

The relevant rule sections are as follows.

(a) This rule sets forth preconstruction review requirements for greenhouse gases (GHG). The provisions of this rule apply only to GHGs as defined by EPA to mean the air pollutant as an aggregate group of six GHGs: carbon dioxide [CO_2], nitrous oxide [N_2O], methane [CH_4], hydrofluorocarbons [HFCs], perfluorocarbons [PFCs], and sulfur hexafluoride [SF6]. All other attainment air contaminants, as defined in Rule 1702 subdivision (a), shall be regulated for the purpose of Prevention of Significant Deterioration (PSD) requirements pursuant to Regulation XVII, excluding Rule 1714.

(b) The provisions of this rule shall apply to any source and the owner or operator of any source subject to any GHG requirements under 40 Code of Federal Regulations 52.21 as incorporated into this rule.

(d)(1) An owner or operator must obtain a PSD permit pursuant to this rule before beginning actual construction, as defined in 40 CFR 52.21(b)(11), of a new major stationary source or major modification to an existing major source as defined in 40 CFR 52.21(b)(1) and (b)(2), respectively.

In May 2010, EPA issued the GHG permitting rule officially known as the "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" (GHG Tailoring Rule), in which EPA defined six GHG pollutants (collectively combined and measured as carbon dioxide equivalent [CO_2e]) as NSR-regulated pollutants and therefore subject to PSD permitting, including the preparation of a BACT analysis for GHG emissions.

The EPA's PSD and Title V Permitting Guidance for Greenhouse Gases, March 2011, provide applicability criteria. Under Tailoring Rule Step 2, the PSD Applicability Test for GHGs in PSD Permits Issued on or after July 1, 2011 indicates that PSD applies to the GHG emissions from a proposed modification to an existing source if any of three sets of applicability criteria are met. The set of applicability criteria applicable to the AEC is as follows:

- Modification is otherwise subject to PSD (for another regulated NSR pollutant), and has a GHG emissions increase and net emissions increase:

- Equal to or greater than 75,000 TPY CO_2e, and
- Greater than -0- TPY mass basis

In *Utility Air Regulatory Group v. EPA* (No. 12-1146), issued 6/23/14, the Supreme Court issued a decision addressing the application of stationary source permitting requirements to greenhouse gases (GHG). The Court said that EPA may not treat greenhouse gases as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or Title V permit. The Court also said that that the EPA could continue to require that PSD permits, otherwise required based on emissions of conventional pollutants, to contain limitations on GHG emissions based on the application of BACT.

In response to the Supreme Court decision, the EPA has undertaken various actions to explain the next steps in GHG permitting and conduct rulemaking action to make the appropriate revisions to the PSD and operating permit rules. In a memo, dated 7/24/14, regarding "Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in *Utility Air Regulatory Group v. Environmental Protection Agency*," the EPA explained it will no longer require PSD or Title V permits for Step 2 sources. (The AEC is a major source for which a Title V permit is required.)

The EPA issued a proposed rule to revise provisions in the PSD and Title V permitting regulations applicable to greenhouse gases (40 CFR Parts 51, 52, 60, 70, and 71) to fully conform with recent court decisions, as well as implementing other provisions, in "Revisions to the Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas (GHG) Permitting Regulations and Establishment of a Significant Emissions Rate (SER) for GHG Emissions Under the PSD Program," 81 Federal Register 68110 (October 3, 2016). This proposed rule has not been finalized.

Analysis:

The **FDOC** determined that the AEC modification was otherwise subject to PSD for other regulated NSR pollutants, NOx and PM_{10}, pursuant to the Rule 1703 analysis. The analysis concluded that the greenhouse gases were subject to PSD review because the CO_2e emissions increase and net emissions increase constitute significant increases. A top-down BACT analysis for carbon monoxide (CO2) was performed for the auxiliary boiler. BACT requirements were determined to be exclusive use of natural gas and good combustion practices.

For **A/N 604014 & 613323** under evaluation here**,** BACT for the auxiliary boiler is not required to be re-evaluated because the condition changes will not increase emissions.

Regulation XX—RECLAIM

- ***Rule 2002—Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx)***

(c)(2)(C) specifies the applicable starting emission factor is found in Table 1—RECLAIM NOx Emission Factor. For Major NOx Sources, these emission factors are required to be used until the CEMS is certified, not to exceed one year after start of unit operation.

Analysis:

- **FDOC Summary, A/N 579158**

From Rule 2002, Table 1:

Nitrogen Oxides Basic Equipment	Fuel	"Throughput" Units	Starting Ems Factor*	2000 (Tier I) Ending Emission Factor
Boilers, Heaters, Steam Gens****	Natural Gas	Mmcf	38.460	38.460

**** Newly installed or Modified after the year selected for maximum throughput for determining starting allocations pursuant to Rule 2002(c)(1), and meeting BACT limits in effect at the time of installation.

Accordingly, condition A99.5 specifies the interim RECLAIM emission factor is 38.46 lbs NOx/mmcf during the interim period prior to CEMS certification.

As Rule 2012(h)(6) provides the Facility Permit holder which installs a new major source at an existing facility shall install, operate, and maintain all required or elected monitoring, reporting, and recording systems no later than 12 months after the initial startup of the major NOx source, the use of these interim emission factors shall not exceed one year after start of unit operation.

- **A/N 604014 & 613323 --Condition Changes**

As a result of the increase from 30 hours to 100 hours for the auxiliary boiler commissioning, condition A99.6 will be added to specify the interim emission factor for the commissioning period during which the auxiliary boiler is assumed to be operating at uncontrolled levels. The commissioning emission factor of 104.20 lbs/mmscf NOx is calculated from the commissioning data in *Table 27 - Auxiliary Boiler Commissioning Emissions* above.

- ***Rule 2005—New Source Review for RECLAIM***

This rule sets forth pre-construction review requirements for modifications to RECLAIM facilities.

- ***(c)(1)(A)--BACT***

See the *Rule 1703(a)(2)* analysis, above.

- ***(c)(1)(B)--Modeling***

  For existing RECLAIM facilities, the Executive Offer shall not approve an application for a Facility Permit Amendment to authorize the installation of a new source which results in an emission increase, unless the applicant demonstrates that the operation of the source will not result in a significant increase in the air quality concentration for NO_2 as specified in Appendix A of the rule. Rule 2000(c)(71) defines "source" as "any individual unit, piece of equipment or process which may emit an air contaminant and which is identified, or required to be identified, in the RECLAIM Facility Permit." Therefore, modeling is required on a per permit unit basis. Rule 1304(a) provides an exemption from the modeling requirements of Rule 1303(b)(1), but not Rule 2005(c)(1)(B). (The standards in Appendix A are outdated. The modeling analysis below is based on current ambient air quality standards.)

  Analysis:

  The **FDOC** provided a modeling analysis for the normal operation of the auxiliary boiler that demonstrated compliance with the ambient air quality standards for Rule 1303 (CO, PM_{10}, SO_2) and Rule 2005 (NO_2), as set forth in *Table 57A - Modeled Results - Normal Operation for Auxiliary Boiler*. The FDOC also provided a modeling analysis for the simultaneous commissioning of the two combined-cycle turbine with the auxiliary boiler in normal operation that demonstrated compliance with the ambient air quality standards, as set forth in *Table 59 - Modeled Results – Commissioning for AEC CCGT (Auxiliary Boiler in Normal Operation)*. A separate modeling analysis for the boiler commissioning was not required because the impacts of the equivalent of two startups per day (6 hours/day) for five days would be minor.

  For **A/N 604014 & 613323** under evaluation here, the commissioning duration will increase from 30 hr to 100 hrs. For the FDOC, modeling for the commissioning period was not required because the impacts of the equivalent of two startups per day (6 hr/day) for 5 days (30 hours) would be minor. For these applications, impacts for the increase to 100 hours spread over three months will continue to be minor.

- ***(c)(2)—Offsets***

  Paragraph (c)(2) requires RECLAIM facilities to hold sufficient RTCs to offset the first year of operation's emissions increase from a new, relocated, or modified source before commencement of such operation. Before Rule 2005 was amended on 6/3/11, Rule 2005(f)(1) required RECLAIM facilities to hold RTCs for each subsequent compliance year prior to each compliance year for the same sources. Further, facilities subject to this NSR hold requirement were generally required to hold and not transfer out of their Allocation accounts the specified RTCs for each year until the compliance year was over.

  On 6/3/11, Rule 2005 was amended to remove existing facilities that do not have emissions greater than the level of their 1994 allocation plus non-tradable credits (NTCs) from section (f)(1). Per

Rule 2000(c)(35), an existing facility is "any facility that submitted Emission Fee Reports pursuant to Rule 301 – Permit Fees, for 1992 or earlier years, or with valid District Permits to Operate issued prior to October 15, 1993, and continued to be in operation or possess valid District permits on October 15, 1993." Per Rule 2000(c)(51), a new facility is "any facility which has received all District Permits to Construct on or after October 15, 1993."

Existing facilities that do not have emissions greater than the level of their 1994 allocation plus NTCs are only subject to the "hold" requirement for the first year of operation of each source with an emissions increase (the period commencing at the start of operation and concluding 364 days later; 365 days later if the period includes a leap day).

A determination was required regarding whether AEC is subject to the RTC hold requirement the first year only (condition I297), or the first year and each subsequent year (condition I296). Southern California Edison (SCE) installed all six utility boilers by 1966, which is prior to 10/15/93. The AES Corporation purchased the power plant from SCE in 1998. Subsequently, AES Alamitos received change of operator permits, not Permits to Construct, for the power plant in 1999. The NOx RTCs initially allocated was 704,485 pounds. The RTCs required for the first year of operation of the combined-cycle turbines and auxiliary boiler are 218,105 pounds. The RTCs required for the first year of operation of the simple-cycle turbines are 274,300 pounds. From *Table 45*, the NOx potential to emit for AEC for a normal operating year is 274,120.0 pounds (137.06 tpy). All RTC requirements are less than the initial allocation. Therefore, since the AEC will be an existing facility that will not exceed the initial allocation, it will be required to hold RTCs for the first year of operation only for each NOx-emitting equipment.

Rule 2005(d) specifies the RECLAIM credit calculation shall be based on the potential to emit or on a permit condition limiting the source's emissions.

Analysis:
The **FDOC** provided the following analysis.

- RTCs Required to Be Held the First Year of Operation
  Auxiliary Boiler
  Condition I297.7 will require auxiliary boiler to hold 1351 pounds of RTCs the first year from the annual emissions calculations above.

For **A/N 604014 & 613323** under evaluation here, condition I297.7 will not be revised. AES has indicated the condition I297.7 holding requirement is sufficient for the increased commissioning period of 100 hours.

- ***(g)—Additional Federal Requirements for Major Stationary Sources***
  For (g)(1) - (g)(4), see Rule 1303(b)(5) analysis above.

- ***(h)—Public Notice***
  See Rule 212 analysis above.

- ***(i)—Rule 1401 Compliance***
  See Rule 1401 analysis above.

- ***Rule 2012-RECLAIM Monitoring Recording and Recordkeeping Requirements***
  The purposes of this rule is to establish the monitoring, reporting and recordkeeping requirements for NOx emissions under the RECLAIM program.

  Analysis:
  *The **FDOC** provided the following analysis. For **A/N 604014 & 613323** under evaluation here, the analysis remains the same as for the FDOC.*

  Classification as Major NOx Source
  Auxiliary Boiler: Rule 2012(c)(1)(A)(i) classifies any boiler with a maximum rated capacity greater than or equal to 40 but less than 500 million Btu per hour and an annual heat input greater than 90 billion Btu per year as a major NOx source. The auxiliary boiler is rated at 70.8 MMBtu/hr. From the emissions calculations above, the annual heat input is 189.12 billion Btu/yr. Therefore, the auxiliary boiler is a major NOx source.

  Compliance Schedule
  Rule 2012(h)(6) provides that the Facility Permit holder which installs a new major source at an existing facility shall install, operate, and maintain all required or elected monitoring, reporting, and recording systems no later than 12 months after the initial startup of the major NOx source. During the interim period between the initial startup of the major NOx source and the provisional certification date of the CEMS, the Facility Permit holder shall comply with the monitoring, reporting, and recordkeeping requirements of paragraphs (h)(2) and (h)(3) of this rule. (Condition D82.3 implement this requirement.)

  Paragraph (h)(2) provides that interim reports shall be submitted monthly for major and large sources. Paragraph (h)(3) provides that the Facility Permit holder shall install, maintain, and operate a totalizing fuel meter for each major source. Rule 2012, Appendix A, Chapter 2 states on pg. Rule 2012A-2-1 that major sources shall be allowed to use an interim reporting procedure to measure and record NOx emissions on a monthly basis according to the requirements specified in Chapter 3 for large sources. Chapter 3 states on pg. Rule 2012A-3-1 that the interim reporting is specified in subdivision D, paragraph 1. Paragraph 1, in turn, provides that the interim reporting shall be based on fuel usage and emission factor(s).

  See Rule 2002 above for further discussion on interim emission factors.

Regulation XXX—Title V Permits

- ***Rule 3000—General***

The proposed project is considered as a "minor permit revision" to the RECLAIM/Title V permit for this facility.

(b) Definitions

(15) *MINOR PERMIT REVISION* means any Title V permit revision that:

(A)

(i) does not require or change a case-by-case evaluation of: reasonably available control technology (RACT) pursuant to Title I of the federal Clean Air Act; or maximum achievable control technology (MACT) pursuant to 40 CFR Part 63, Subpart B;

(ii) does not violate a regulatory requirement;

Analysis: Paragraphs (A)(i) – (A)(ii) do not apply to the proposed corrections to the manufacturer and model number of the boiler and burner, and to the correction of the number of commissioning hours which do not affect the emissions calculations.

(iii) does not require any significant change in monitoring terms or conditions in the permit;

(iv) does not require relaxation of any recordkeeping, or reporting requirement, or term, or condition in the permit;

Analysis: The correction of the number of commissioning hours which do not affect the emissions calculations does not constitute a significant change or relaxation to the condition and is in compliance with paragraphs (A)(iii) – (A)(iv). The proposed installation of the CO CEMS will provide more accurate emissions monitoring than the use of the CO emission factor.

(v) does not result in an emission increase of RECLAIM pollutants over the facility starting Allocation plus nontradeable Allocations, or higher Allocation amount which has previously undergone a significant permit revision process;

Analysis: The condition I297.7 holding requirement will not be increased. AES has indicated the condition I297.7 holding requirement is sufficient for the increased commissioning period of 100 hours.

(vi) does not result in an increase in emissions of a pollutant subject to Regulation XIII - New Source Review or a hazardous air pollutant;

Analysis: The proposed condition changes will not increase emissions.

(vii) does not result in an increase in GHG emissions of >75,000 tpy CO2e;

Analysis: The proposed condition changes will not increase emissions.

(viii) does not establish or change a permit condition that the facility has assumed to avoid an applicable requirement;

(ix) is not an installation of a new permit unit subject to a New Source Performance Standard (NSPS) pursuant to 40 CFR Part 60, or a National Emission Standard for Hazardous Air Pollutants (NESHAP) pursuant to 40 CFR Part 61 or 40 CFR Part 63; and,

(x) is not a modification or reconstruction of an existing permit unit, resulting in new or additional NSPS requirements pursuant to 40 CFR Part 60, or new or additional NESHAP requirements pursuant to 40 CFR Part 61 or 40 CFR Part 63; or ….

Analysis: Paragraphs (A)(viii) – (A)(x) do not apply to the proposed condition changes.

- ***Rule 3003—Applications***

(j) EPA Review

(1) The Executive Officer shall submit to the EPA Administrator:

(A) each application for initial permit, permit renewal, minor permit revision, de minimis significant permit revision and significant permit revision;

(B) each proposed permit for initial permit, renewal permit, or permit revision, excluding administrative permit revisions;

(C) any revisions to the proposed permit in response to public or affected State comments;

(D) a copy of any notices required by Rules 3003, 3005, or 3006; and,

(E) each final Title V permit, within 5 working days of permit issuance.

(k) EPA Objection

(1) No permit or permit revision for which an application must be transmitted to EPA pursuant to subdivision (j) of this rule may be issued if the EPA objects to its issuance in writing within 45 days of receipt of the proposed permit and all necessary supporting information, or within 90 days if the EPA provides a written request to delay the permit

issuance on the basis that an additional 45 days is necessary to review the public and affected State comments made to the proposed permit. The objection shall include a statement of the reasons for the objection and a description of the terms and conditions that the permit must include to respond to the objections.

(m) Review by Affected States

(1) Except for administrative permit revisions, the Executive Officer shall give notice of each proposed permit to any affected State on or before the notice is provided to the EPA.

(2) Any affected State may provide recommendations in writing, based upon applicable requirements or requirements of 40 CFR Part 70, with respect to the proposed permit, within 30 days of receipt of the notice.

Analysis: Pursuant to Rule 3003(j), the proposed permit package for the minor revision will be submitted to EPA for a 45-day review period. Pursuant to Rule 3003(m), written notice will be sent to the affected states for the 30-day review period. If comments are received from the affected states, the EPA 45-day review period will begin after the South Coast AQMD's responses to comments have been submitted to EPA along with any changes to the documents previously submitted.

FEDERAL REGULATIONS

40 CFR Part 60, Subpart Dc--Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

*The **FDOC** provided the following analysis. For **A/N 604014 & 613323** under evaluation here, the analysis remains the same as for the FDOC.*

§60.40c Applicability and delegation of authority

The affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and has a maximum design input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr.

***Analysis*:** Subpart Dc is applicable to the auxiliary boiler, rated at 70.8 MMBtu/hr, because the initial construction will be commenced after June 9, 1989.

§60.48c(g)(2) As an alternative to meeting the requirements of paragraph (g)(1) [requires the recording and maintenance of records of the amount of each fuel combusted during each operating day], the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

Analysis: There are no emission standards, compliance, stack testing, or emission monitoring requirements for natural gas fired boilers. This boiler will combust only natural gas.

This paragraph requires the recording of the calendar monthly usage of natural gas and the use of a non-resettable totalizing fuel meter.

Rule 2012 requires this RECLAIM major NOx source to meet stringent requirements regarding the recording of calendar monthly usage and the use of a non-resettable totalizing fuel meter. Moreover, Rule 2012 requires a NOx CEMS which is not required by this subpart. Section F: RECLAIM Monitoring and Source Testing of the facility permit is comprised of a standard list of operating conditions for RECLAIM facilities, including requirements for NOx major sources. Pursuant to permitting procedure, permit conditions enforcing standard RECLAIM requirements are not added to a facility permit. In contrast, RECLAIM conditions regarding the number of RTCs required and interim emission factors are included as permit conditions because they are based on emissions calculations that are specific to a facility.

40 CFR Part 63, Subpart JJJJJJ—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

*The **FDOC** provided the following analysis. For **A/N 604014 & 613323** under evaluation here, the analysis remains the same as for the FDOC.*

§63.11193--This subpart is applicable to owner or operator of industrial, commercial, or institutional boiler as defined in §63.11237 that is located at, or is part of, an area source of hazardous air pollutants (HAP), as defined in §63.2, except as specified in §63.1195.

§63.11237--"Industrial boiler" means "a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity."

Analysis: As determined for *Subpart YYYY--NESHAPS for Stationary Combustion Turbines*, the AEC will be an area source. The auxiliary boiler will be an industrial boiler.

§63.11195--The types of boilers listed in paragraphs (a) through (g) of this section are not subject to this subpart and to any requirements in this subpart.

(e) A gas-fired boiler as defined in this subpart.

§63.11237--"Gas-fired boiler" includes any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

***Analysis*:** As a gas-fired boiler, the auxiliary boiler is not subject to this subpart.

40 CFR Part 64 – Compliance Assurance Monitoring

For A/N 604014 & 613323, the analysis expands upon the FDOC analysis but reaches the same conclusion.

The Compliance Assurance Monitoring (CAM) rule, 40 CFR Part 64, specifies the monitoring, reporting, and recordkeeping criteria that is required to be conducted by Title V facilities to demonstrate ongoing compliance with emission limitations and standards. The rule is intended to provide "reasonable assurance" that the control systems are operating properly to maintain compliance with the emission limits.

In general, CAM applies to emissions units that meet all of the following conditions:

- the unit is located at a major source for which a Title V permit is required: and
- the unit is subject to an emission limitation or standard; and
- the unit uses a control device to achieve compliance with a federally enforceable limit or standard; and
- the unit has potential pre-control emissions (Title V renewal) or post-control emissions (initial Title V or significant revision) of at least 100% of the major source amount; and
- the unit is not otherwise exempt from CAM.

CAM applicability is analyzed in the table below. Since the permitting of the AEC is for a significant Title V revision, the applicability is based on potential post-control emissions.

Equipment (device no.)	Subject to Emission Limitation or Standard	Use of External Control Device to Achieve Compliance with Limitation	Potential Post-Control Emissions of at Least 100% of the Major Source Amount	Exemption	Applicability
Auxiliary Boiler (D181)	CO: 50 ppmv	NO			NO
	NOx: 5 ppmv	YES	NO ≥ 10 TPY	CEMS	NO

The auxiliary boiler (D181) is subject to BACT limits for CO and NOx.

CO: The boiler is not equipped with an external control device for CO. Therefore, the boiler is not subject to CAM requirements for CO.

NOx: The boiler is equipped with a selective catalytic reduction system to achieve compliance with the federally enforceable NOx limit of 5.0 ppm. The highest annual post-controlled NOx emissions is 0.68 tpy, which is lower than the major source threshold of 10 tpy NOx. Consequently, the boiler is not subject to CAM requirements for NOx.

STATE REGULATIONS

California Environmental Quality Act (CEQA)

CEQA applies to projects undertaken by a public agency, funded by a public agency, or requires an issuance of a permit by a public agency. A "project" means the whole of an action that has a potential for resulting in physical change to the environment, and is an activity that may be subject to several discretionary approvals by government agencies. A project is exempt from CEQA if by statute, if considered ministerial or categorical, where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment.

On 4/4/19, AES submitted a *Petition for Post-Certification Amendment, Modification of Gas Turbine Operating Hours and Combined Cycle Gas Turbine (CCGT) Stack Height* to amend the CEC License. AES and the CEC are in the process of incorporating the other pending application changes that had been submitted to the South Coast AQMD, including for the auxiliary boiler and SCR, into the CEC license for the AEC.

RECOMMENDATION

Based on the above analysis, it is recommended that the Permits to Construct be issued following the conclusion of the required EPA review period, subject to any comments received during these periods.