JEFF LANDRY
GOVERNOR

COURTNEY J. BURDETTE
SECRETARY

STATE OF LOUISIANA

DEPARTMENT OF ENVIRONMENTAL QUALITY
OFFICE OF ENVIRONMENTAL SERVICES

Certified Mail No.

Activity No.: PER20240001
Agency Interest No. 246887

Ms. Lisa Carty
Vice President, Environmental
Camellia Power LLC
500 Alexander Park Drive, Suite 300
Princeton, NJ 08540

RE: Initial Part 70 Operating Permit
Camellia Power LLC - Camellia Power Unit 2
Plaquemine, Iberville Parish, Louisiana

Dear Ms. Carty:

This is to inform you that the initial permit for the above referenced facility has been approved under LAC 33:III.501. The permit is both a state preconstruction and Part 70 Operating Permit. The submittal was approved on the basis of the emissions reported and the approval in no way guarantees the design scheme presented will be capable of controlling the emissions as to the types and quantities stated. A new application must be submitted if the reported emissions are exceeded after operations begin. The synopsis, data sheets and conditions are attached herewith.

It will be considered a violation of the permit if all proposed control measures and/or equipment are not installed and properly operated and maintained as specified in the application.

Operation of this facility is hereby authorized under the terms and conditions of this permit. This authorization shall expire at midnight on the _____ of _____, 2030, unless a timely and complete renewal application has been submitted six months prior to expiration. Terms and conditions of this permit shall remain in effect until such time as the permitting authority takes final action on the application for permit renewal. The permit number and agency interest number cited above should be referenced in future correspondence regarding this facility.

Please be advised that pursuant to provisions of the Environmental Quality Act and the Administrative Procedure Act, the Department may initiate review of a permit during its term. However, before it takes any action to modify, suspend or revoke a permit, the Department shall, in accordance with applicable statutes and regulations, notify the permittee by mail of the facts or operational conduct that warrant the intended action and provide the permittee with the opportunity to demonstrate compliance with all lawful requirements for the retention of the effective permit.

Done this _____ day of _____, 2025.

Permit No.: 1280-00300-V0

Sincerely,

Amanda Vincent, PhD, PMP
Assistant Secretary
AV:alr
c: EPA Region VI

AIR PERMIT BRIEFING SHEET
AIR PERMITS DIVISION
LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine, Iberville Parish, Louisiana

I. Background

Camellia Power LLC (Camellia Power) is proposing to construct and operate the Camellia Power Unit 2 (Unit 2), which will consist of a combined cycle gas turbine (CCGT Unit) and other ancillary equipment. The proposed Unit 2 will be contiguous and under common control with Magnolia Power Generating Station Unit 1 (AI 222431).

This is the initial Title V permit for the Camellia Power Unit 2.

II. Origin

A permit application was submitted by Camellia Power on December 17, 2024, requesting an initial Part 70 operating permit. Additional information was also received on July 2, 2025.

III. Description

Camellia Power proposes to construct a power plant, Camellia Power Unit 2, consisting of a natural gas-fired combined cycle gas turbine (CCGT Unit) and other ancillary equipment in Iberville Parish, Louisiana. The CCGT Unit [Emission Point Number (EPN) CCGT-2, EQT0002] will include a heat recovery steam generator (HRSG) and have a net nominal output of approximately 730 megawatts.

Ancillary equipment associated with Unit 2 will include:

- One (1) 2,937 horsepower Emergency Diesel Generator (EPN EGEN-2, EQT0003);
- One (1) 355 horsepower Emergency Diesel Fire Water Pump (EPN FWP-2, EQT0004);
- One (1) 80 MMBtu/hr Auxiliary Boiler (EPN BOIL-2, EQT0001) to provide auxiliary steam for CCGT-2 during startup to reduce startup duration;
- One (1) 5,475 gallon Atmospheric Drains Tank (EPN TK-6, EQT0005);
- Four (4) Circuit Breakers (EPN CB-2, EQT0006) insulated with sulfur hexafluoride (SF_6); and
- Unit 2 fugitive sources (EPN FUG-2, FUG0001).

CCGT-2 will use either natural gas or a blend of up to 50% hydrogen and natural gas as fuel, but Camellia Power will not use the blended gas during startup or shutdown operations. The HRSG will be equipped with duct burners, which provide supplemental natural gas firing, allowing the facility to vary the unit's electrical output to meet customer demand.

Excess heat from the HRSG will convert incoming feed water to steam, which will rotate the steam turbine generator. Combined-cycle units are more efficient than gas turbines or steam turbine generators alone because additional electricity is generated from the steam created from the combustion turbine's waste heat.

The combustion of natural gas in the combustion turbine has the potential to generate NO_X emissions, which will be controlled using dry low-NO_X combustors, Selective Catalytic Reduction (SCR), and good combustion practices. An oxidation catalyst will control VOC and CO emissions. The use of pipeline quality natural gas, along with good combustion practices, will minimize PM_{10}, $PM_{2.5}$, SO_2, sulfuric acid mist, and CO_2e emissions.

The CCGT Unit selected by Camellia Power for Unit 2 will be capable of combusting up to 100% hydrogen fuel, thus producing electricity without combustion of hydrocarbons.

This permit also addresses potential emissions during the initial startup and commissioning of the Camellia Power Unit 2 (EPN CCGT-COMM-2, SCN0001). The commissioning phase allows for the Engineering Procurement and Construction (EPC) contractor to demonstrate that the facility is built to specification and capable of performing as designed. During this phase, a series of engineering tasks and tests are performed to clean, inspect, assess, adjust, and tune all aspects of the combined cycle unit, including fuel firing at various loads; combustion turbine emissions tuning; power generation; HRSG steam production and purity; HRSG emissions control systems; and instrumentation, monitoring, and operational control systems. Commissioning includes tuning, steam blows for cleaning, steam turbine operation and testing, SCR operation and testing, and performance testing in order to validate the unit operates as designed. The duration of the commissioning phase is estimated to be 650 hours.

Permitted emissions in tons per year (tpy) are as follows:

Pollutant	Emissions
PM_{10}	131.21
$PM_{2.5}$	131.21
SO_2	38.12
NO_X	176.50
CO	243.39
VOC	101.19
CO_2e	2,699,484

VOC LAC 33:III.Chapter 51 Toxic Air Pollutants (TAPs):

Pollutant	Emissions
1,3-Butadiene	0.01
Acetaldehyde	0.85
Acrolein	0.14
Benzene	0.28
Dichlorobenzene	0.01
Ethyl benzene	0.68
Formaldehyde	4.70
n-Hexane	4.85
Naphthalene	0.03
Polynuclear Aromatic Hydrocarbons	0.05
Propylene Oxide	0.62
Toluene	2.78
Xylene (mixed isomer)	1.36
Total TAPs	11.54

LAC 33:III.Chapter 51 Toxic Air Pollutants (TAPs):

Pollutant	Emissions
Ammonia	145.54
Barium (and compounds)	0.01
Cadmium (and compounds)	0.003
Chromium VI (and compounds)	0.004
Copper (and compounds)	0.002
Manganese (and compounds)	0.01
Mercury (and compounds)	0.001
Nickel (and compounds)	0.006
Sulfuric Acid	25.40
Zinc (and compounds)	0.08
Total TAPs	171.052

IV. Type of Review

This permit was reviewed for compliance with 40 CFR 70, the Louisiana Air Quality Regulations, New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and Prevention of Significant Deterioration (PSD). Camellia Power Unit 2, because it is contiguous and under common control with Magnolia Generating Station Unit 1

will be major source of hazardous air pollutants (HAPs) and a major source of TAPs under LAC 33:III.Chapter 51. Ammonia and sulfuric acid are regulated as TAPs, but not HAPs.

The TAP emissions generated from the combustion of Group 1 virgin fossil fuels, and the duct burners, which are electric utility steam generating units, are exempt from Chapter 51 Subchapter A requirements (per LAC 33:III.5105.B.2 and B.3.a). However, because ammonia is generated from the SCR control system, the aforementioned exemptions do not apply to this compound.

The facility's ammonia emissions (which exceed the Chapter 51 major source threshold) are subject to Chapter 51 requirements. However, since ammonia is a Class III TAP, Maximum Achievable Control Technology (MACT) requirements do not apply per LAC 33:III.5109.A.

The provisions of 40 CFR 97 Subpart EEEEE have been included in this permit in accordance with 40 CFR 52.38(b)(2)(ii)(D)(*1*). If the stay is lifted, the provisions of 40 CFR 97 Subpart GGGGG shall apply per 40 CFR 52.38(b)(2)(iii)(A).

Prevention of Significant Deterioration (PSD)

Camellia Power Unit 2 will be a major stationary source under the PSD program, LAC 33:III.509. The emissions increases associated with the proposed facility are as follows:

Pollutant	Emissions	PSD de minimis	Review required?
PM_{10}	131.21	15	Yes
$PM_{2.5}$	131.21	10	Yes
SO_2	38.12	40	No
NO_X	176.50	40	Yes
CO	243.39	100	Yes
VOC	101.19	40	Yes
H_2SO_4 Mist	25.40	7	Yes
CO_2e	2,699,483	75,000	Yes

The proposed facility will result in significant net emissions increases of PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, H_2SO_4 Mist, and CO_2e; therefore, PSD requirements, including best available control technology (BACT), apply to these pollutants. PSD review for this project is documented in PSD permit PSD-LA-863. The requirements of PSD-LA-863 are incorporated into this permit.

Offsets

In accordance with LAC 33:III.504.M, emission offsets are required for NO_X and/or VOC emissions in excess of 50 tons per year from a new major source at an offset ratio of 1.0 to 1 for each pollutant. As shown in the table below, Camellia Power has secured sufficient emission credits to offset NO_X and VOC emissions.

Pollutant	NOx	VOC
Total Emissions (TPY)	176.50	101.19
Offset Ratio	1.0 to 1	1.0 to 1
Offsets Required	126.50	51.19

V. Credible Evidence

Notwithstanding any other provisions of any applicable rule or regulation or requirement of this permit that state specific methods that may be used to assess compliance with applicable requirements, pursuant to 40 CFR Part 70 and EPA's Credible Evidence Rule, 62 Fed. Reg. 8314 (Feb. 24, 1997), any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed shall be considered for purposes of Title V compliance certifications. Furthermore, for purposes of establishing whether or not a person has violated or is in violation of any emissions limitation or standard or permit condition, nothing in this permit shall preclude the use, including the exclusive use, by any person of any such credible evidence or information.

VI. Public Notice

In accordance with LAC 33:III.531.A.3, a notice requesting public comment and announcing a public hearing on the proposed permit was published on the department's website on **<date>**. On **<date>**, copies of the public notice were mailed to the individuals who have requested to be placed on the mailing list maintained by the Office of Environmental Services (OES). The proposed permit was submitted to EPA on **<date>**. All comments will be considered prior to a final permit decision.

AIR PERMIT BRIEFING SHEET
AIR PERMITS DIVISION
LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine, Iberville Parish, Louisiana

VII. Effects on Ambient Air

Emissions associated with the proposed facility were reviewed by LDEQ to assure compliance with the federal national ambient air quality standards (NAAQS) for criteria pollutants and Louisiana ambient air standards (AAS) for toxic air pollutants.

Dispersion Model(s) Used: AERMOD (2024)

Pollutant	Time Period	Calculated Maximum Ground Level Concentration	Louisiana Toxic Air Pollutant Ambient Air Quality Standard or (National Ambient Air Quality Standard {NAAQS})
$PM_{2.5}$	24-hour	0.84	(35 $\mu g/m^3$)
	Annual	0.10	(9 $\mu g/m^3$)
PM_{10}	24-hour	0.85	(150 $\mu g/m^3$)
NO_2	1-hour	2.94	(188 $\mu g/m^3$)
	Annual	0.38	(100 $\mu g/m^3$)
CO	1-hour	675.16	(40,000 $\mu g/m^3$)
	8-hour	297.98	(10,000 $\mu g/m^3$)
Ammonia	8-hour	28.72	640 $\mu g/m^3$

VIII. General Condition XVII Activities

		Emission Rates – tons per year				
Work Activity	Schedule	PM_{10}	SO_2	NO_X	CO	VOC
None						

IX. Insignificant Activities

ID No.:	Description	Citation
IA-1	Fuel Gas Conditioning Drain Tank (2,480 gallons)	LAC 33:III.501.B.5.A.3
IA-2	Emergency Diesel Generator Fuel Tank (1,700 gallons)	LAC 33:III.501.B.5.A.3
IA-3	Emergency Diesel Fire Water Pump Fuel Tank (572 gallons)	LAC 33:III.501.B.5.A.3
IA-4	Lube Oil Storage Tank 3 (150 gallons)	LAC 33:III.501.B.5.A.3

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Camellia Power Unit 2
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Plaquemine, Iberville Parish, Louisiana

ID No.:	Description	Citation
IA-5	Lube Oil Storage Tank 4 (150 gallons)	LAC 33:III.501.B.5.A.3
IA-6	Water Wash Drains Tank (8,000 gallons)	LAC 33:III.501.B.5.A.3
IA-7	Oil/Water Separator (3,000 gallons)	LAC 33:III.501.B.5.A.3
IA-8	Storage and Use of Water Treating Chemicals	LAC 33:III.501.B.5.B.8

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine, Iberville Parish, Louisiana

X. Table 1. Applicable Louisiana and Federal Air Quality Requirements																		
ID No.:	Description	LAC 33:III.Chapter																
		5▲	509	9	11	13	15	2103	2111	2113	2122	22	29*	51*	5109.A*	53*	56	59*
UNF0001	FW Unit 2 – Facility Wide Unit 2	1	1	1	1	1				1				1			1	3
EQT0001	BOIL-2 – Auxiliary Boiler		1		2	1	3					3		2				
EQT0002	CCGT-2 – Combined Cycle Gas Turbine 2 w/ Duct Burners and HSRG		1		2	1	1					2		2				
SCN0002	CCGT-2-SUSD – Combined Cycle Gas Turbine 2 – Startup and Shutdown	1	1															
EQT0003	EGEN-2 – Emergency Diesel Generator		1		1	1	3					2		2				
EQT0004	FWP-2 – Emergency Diesel Fire Water Pump		1		1	1	3					2		2				
EQT0005	TK-6 – Atmospheric Drain Tank		1					3										
FUG0001	FUG-2 – Unit 2 Fugitive Emissions		1						3		3				3			
CRG0001	ACRN-2 – Acid Rain Requirements																	
CRG0002	CSAPR – Cross-State Air Pollution Rule (CSAPR) Requirements																	

* The regulations indicated above are State Only regulations.

▲ All LAC 33:III.Chapter 5 citations are federally enforceable including LAC 33:III.501.C.6 citations, except when the requirement found in the "Specific Requirements" report specifically states that the regulation is State Only.

LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine, Iberville Parish, Louisiana

KEY TO MATRIX

1 -The regulations have applicable requirements that apply to this particular emission source.
-The emission source may have an exemption from control stated in the regulation. The emission source may not have to be controlled but may have monitoring, recordkeeping, or reporting requirements.

2 -The regulations have applicable requirements that apply to this particular emission source but the source is currently exempt from these requirements due to meeting a specific criterion, such as it has not been constructed, modified or reconstructed since the regulations have been in place. If the specific criteria changes the source will have to comply at a future date.

3 -The regulations apply to this general type of emission source (i.e. vents, furnaces, towers, and fugitives) but do not apply to this particular emission source.

Blank – The regulations clearly do not apply to this type of emission source.

LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine, Iberville Parish, Louisiana

X. Table 1. Applicable Louisiana and Federal Air Quality Requirements

ID No.	Description	40 CFR 60 NSPS											40 CFR 63				40 CFR					
		A	D	Da	Db	Dc	Kc	GG	4I	4J	4K	4Ta	A	4Y	4Z	5D	64	68	72	75	82	97
UNF0001	FW Unit 2 – Facility Wide Unit 2	1											1					3			3	
EQT0001	BOIL-2 – Auxiliary Boiler		3	3	3	1										1						
EQT0002	CCGT-2 – Combined Cycle Gas Turbine 2 w/ Duct Burners and HSRG		3	3	3	3		2			1	1		1			2					
SCN0002	CCGT-2-SUSD – Combined Cycle Gas Turbine 2 – Startup and Shutdown																					
EQT0003	EGEN-2 – Emergency Diesel Generator								1	3					1							
EQT0004	FWP-2 – Emergency Diesel Fire Water Pump								1	3					1							
EQT0005	TK-6 – Atmospheric Drain Tank						3															
FUG0001	FUG-2 – Unit 2 Fugitive Emissions																					
CRG0001	ACRN-2 – Acid Rain Requirements																		1	1		
CRG0002	CSAPR – Cross-State Air Pollution Rule (CSAPR) Requirements																					1

LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine, Iberville Parish, Louisiana

KEY TO MATRIX

1 -The regulations have applicable requirements that apply to this particular emission source.
-The emission source may have an exemption from control stated in the regulation. The emission source may not have to be controlled but may have monitoring, recordkeeping, or reporting requirements.

2 -The regulations have applicable requirements that apply to this particular emission source but the source is currently exempt from these requirements due to meeting a specific criterion, such as it has not been constructed, modified or reconstructed since the regulations have been in place. If the specific criteria changes the source will have to comply at a future date.

3 -The regulations apply to this general type of emission source (i.e. vents, furnaces, towers, and fugitives) but do not apply to this particular emission source.

Blank – The regulations clearly do not apply to this type of emission source.

XI. Explanation for Exemption Status or Non-Applicability of a Source				
ID No:	Requirement	Status	Citation	Explanation
UNF0001 – FW Unit 2	40 CFR 68 – Chemical Accident Prevention Provisions	Does not apply	40 CFR 68.10	The facility does not produce, handle, process, or store any substances listed in 40 CFR 68.130 in quantities greater than the listed thresholds.
	40 CFR 82 – Protection of Stratospheric Ozone	Does not apply	40 CFR 82	The facility does not use refrigeration units or equipment that contains ozone depleting substances.
	LAC 33:III.Chapter 59 – Chemical Accident Prevention and Minimization of Consequences	Does not apply	LAC 33:III.5907	The facility does not produce, process, handle, or store any of the substances listed in 40 CFR 68.130, Table 59.0 of LAC 33:III.5901 or Table 59.1 of LAC 33:III.5913 in quantities greater than the thresholds listed in those respective places.
EQT0001 – BOIL-2	40 CFR 60 Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators	Does not apply	40 CFR 60.40(a)(1)	The heat input capacity of the source is less than 250 MMBtu/hr; therefore, this rule does not apply.
	40 CFR 60 Subpart Da – Standards of Performance for Electric Utility Steam Generating Units	Does not apply	40 CFR 60.40a(a)(1)	The heat input capacity of the source is less than 250 MMBtu/hr; therefore, this rule does not apply.
	40 CFR 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Unit	Does not apply	40 CFR 60.40b(a)	The heat input capacity of the source is less than 100 MMBtu/hr; therefore, this rule does not apply.
	LAC 33:III.Chapter 11 – Control of Emissions of Smoke	Exempt	LAC 33:III.1107.B	Combusts only natural gas, carbon monoxide, hydrogen, and/or other gaseous fuels with a carbon to hydrogen molecular ratio of less than 0.34.
	LAC 33:III.Chapter 15 – Emission Standards for Sulfur Dioxide	Does not apply	LAC 33:III.1502.A.3	This single point source does not emit or have the potential to emit more than 5 tpy of sulfur dioxide.
	LAC 33:III.Chapter 22 – Control of Emissions of Nitrogen Oxides	Does not apply	LAC 33:III.2201.A	Facility does not have the potential to emit 25 tons or more per year of NO_X when considering exempted point sources.

XI. Explanation for Exemption Status or Non-Applicability of a Source				
ID No:	Requirement	Status	Citation	Explanation
EQT0001 – BOIL-2 (Continued)	LAC 33:III.Chapter 51 – Comprehensive Toxic Air Pollutant Emission Control Program	Exempt	LAC 33:III.5105.B.3.a	Toxic air pollutant emissions from the combustion of Group 1 virgin fossil fuels are exempt from the requirements of Chapter 51.
EQT0002 – CCGT-2	40 CFR 60 Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators	Does not apply	40 CFR 60.40(e)	This unit is subject to 40 CFR 60 Subpart KKKK, and therefore is not subject to this subpart.
	40 CFR 60 Subpart Da – Standards of Performance for Electric Utility Steam Generating Units	Does not apply	40 CFR 60.40a(e)	This unit is subject to 40 CFR 60 Subpart KKKK, and therefore is not subject to this subpart.
	40 CFR 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Unit	Does not apply	40 CFR 60.40b(i)	This unit is subject to 40 CFR 60 Subpart KKKK, and therefore is not subject to this subpart.
	40 CFR 60 Subpart Dc – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Unit	Does not apply	40 CFR 60.40c(a)	This unit will have a maximum design heat input capacity greater than 29 megawatts (MW) (100 MMBtu/hr).
	40 CFR 60 Subpart GG – Standards of Performance for Stationary Gas Turbines	Exempt	40 CFR 60.4305(b)	The stationary combustion turbine is regulated under 40 CFR 60 Subpart KKKK and, therefore, is exempt from the requirements of Subpart GG.
	40 CFR 64 – Compliance Assurance Monitoring	Exempt	40 CFR 64.2(b)(1)(i) & (vi)	This unit is subject to emission limitations or standards proposed by the Administrator after November 15, 1990 and, for CO, permit specifies a continuous compliance determination method.
	LAC 33:III.Chapter 11 – Control of Emissions of Smoke	Exempt	LAC 33:III.1107.B	The combustion unit combusts only natural gas, carbon monoxide, hydrogen, and/or other gaseous fuels with a carbon to hydrogen molecular ratio of less than 0.34.

XI. Explanation for Exemption Status or Non-Applicability of a Source				
ID No:	Requirement	Status	Citation	Explanation
EQT0002 – CCGT-2 (Continued)	LAC 33:III.Chapter 15 – Emission Standards for Sulfur Dioxide	Exempt	LAC 33:III.1503.C	Single point source that emits or has the potential to emit less than 250 tpy of sulfur compounds measured as sulfur dioxide may be exempted from the 2,000 ppm(v) limitation by the administrative authority.
	LAC 33:III.Chapter 22 – Control of Emissions of Nitrogen Oxides	Exempt	LAC 33:III.2201.C.15	This unit is required to comply with more stringent federal NO_X limitation listed under 40 CFR 60 Subpart KKKK. Therefore, the unit is exempt from the requirements of Chapter 22.
	LAC 33:III.Chapter 51 – Comprehensive Toxic Air Pollutant Emission Control Program	Exempt	LAC 33:III.5105.B.2 & 5105.B.3.a	TAP emissions generated from the combustion of Group 1 virgin fossil fuels, and the duct burners, which are electric utility steam generating units, are exempt from the requirements of Chapter 51.
EQT0003 – EGEN-2 EQT0004 – FWP-2	40 CFR 60 Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines	Does not apply	40 CFR 60.4230(a)	The engine will not be a stationary spark ignition internal combustion engine.
	LAC 33:III.Chapter 15 – Emission Standards for Sulfur Dioxide	Does not apply	LAC 33:III.1502.A.3	Single point sources that do not emit or have the potential to emit more than 5 tpy of sulfur dioxide.
	LAC 33:III.Chapter 22 – Control of Emissions of Nitrogen Oxides	Exempt	LAC 33:III.2201.C.14	Diesel fired stationary internal combustion engines are exempt from the requirements of Chapter 22.
	LAC 33:III.Chapter 51 – Comprehensive Toxic Air Pollutant Emission Control Program	Exempt	LAC 33:III.5105.B.3.a	Toxic air pollutant emissions from the combustion of Group 1 virgin fossil fuels are exempt from the requirements of Chapter 51.
EQT0005 – TK-6	40 CFR 60 Subpart Kc – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification After October 4, 2023	Does not apply	40 CFR 60.110c(a)	The tank has a capacity less than 20,000 gallons; therefore, this rule does not apply.

XI. Explanation for Exemption Status or Non-Applicability of a Source

ID No:	Requirement	Status	Citation	Explanation
EQT0005 – TK-6 (Continued)	LAC 33:III.2103 – Storage of Volatile Organic Compounds	Does not apply	LAC 33:III.2103.A	Maximum true vapor pressure of contents stored is less than 1.5 psia.
FUG0001 – FUG-2	LAC 33:III.2111 – Pumps and Compressors	Does not apply	LAC 33:III.2111.A	The facility does not use pumps or compressors that handle VOCs with true vapor pressure greater than or equal to 1.5 psia at handling conditions.
	LAC 33:III.2122 – Fugitive Emission Control for Ozone Nonattainment Area and Specified Parishes	Does not apply	LAC 33:III.2122.A.1	The facility is not a petroleum refinery, natural gas processing plant, synthetic organic chemical manufacturing industry (SOCMI) facility, MTBE manufacturing facility, or polymer manufacturing facility.
	LAC 33:III.Chapter 51 – Comprehensive Toxic Air Pollutant Emission Control Program – Maximum Achievable Control Technology (MACT) Requirements	Does not apply	LAC 33:III.5109.A	The source emits ammonia, which is a Class III TAP; therefore, MACT does not apply.

The above table provides explanation for both the exemption status or non-applicability of a source cited by 1, 2 or 3 in the matrix presented in Section X (Table 1) of this permit.

General Information

AI ID: 246887 Camellia Power LLC - Unit 2
Activity Number: PER20240001
Permit Number: 1280-00300-V0
Air - Title V Regular Permit Initial

Alternate Identifiers	Name	User Group	Dates
1280-00300	CDS Number	CDS Number	07-10-2025

Physical Location: 26620 River Rd
(portion of)
Plaquemine LA 70764

Mailing Address: 500 Alexander Park Dr Ste 300
Princeton NJ 08540

Location of Front Gate:

Related People:	Mail Address	Work Phone	Email	Relationship
Lisa Carty	500 Alexander Park Dr Ste 300 Princeton, NJ 08540	3038422115	lisa.carty@kindle-energy.com	Responsible Official for

Related Organizations:	Mailing Address	Work Phone	Relationship
Camellia Power LLC	500 Alexander Park Ste 300 Princeton, NJ 08540		Air Billing Party for Operates Owns

SIC Codes:

NAIC Codes:

Note: This report entitled "General Information" contains a summary of facility-level information contained in LDEQ's TEMPO database for this facility and is not considered a part of the permit. Please review the information contained in this document for accuracy and completeness. If any changes are required, or if you have questions regarding this document, please email the Permit Support Services Division at facupdate@la.gov.

INVENTORIES

AI ID: 246887 - Camellia Power LLC - Unit 2
Activity Number: PER20240001
Permit Number: 1280-00300-V0
Air - Title V Regular Permit Initial

Subject Item Inventory:

ID	Description	Tank Volume	Max Operating Rate	Normal Operating Rate	Comments	Operating Time
Facility Wide Unit 2						
EQT 0001	BOIL-2 - Auxiliary Boiler			80 MM BTU/hr		8760 hr/yr
EQT 0002	CCGT-2 - Combined Cycle Gas Turbine w/ Duct Burners and HSRG			730 MW		8760 hr/yr
EQT 0003	EGEN-2 - Emergency Diesel Generator			2937 horsepower		100 hr/yr
EQT 0004	FWP-2 - Emergency Diesel Fire Water Pump			355 horsepower		100 hr/yr
EQT 0005	TK-6 - Atmospheric Drains Tank	5475 gallons	100000 gallons/yr	100000 gallons/yr		8760 hr/yr
EQT 0006	CB-2 - Circuit Breakers					8760 hr/yr
FUG 0001	FUG-2 - Unit 2 Fugitive Emissions					8760 hr/yr

Stack Information:

ID	Description	Diameter (feet)	Discharge Area (square feet)	Height (feet)	Velocity (ft/sec)	Flow Rate (cubic ft/min-actual)	Temperature (oF)
Facility Wide Unit 2							
EQT 0001	BOIL-2 - Auxiliary Boiler	2.83		164.04	68.75	25947	158
EQT 0002	CCGT-2 - Combined Cycle Gas Turbine w/ Duct Burners and HSRG	23		199	77.11	1922167	193.9
EQT 0003	EGEN-2 - Emergency Diesel Generator	1		14	324.52	15293	752.1
EQT 0004	FWP-2 - Emergency Diesel Fire Water Pump	.5		14	181.05	2133	1106
SCN 0001	CCGT-COMM-2 - Combined Cycle Gas Turbine 2 - Commissioning Activities	23		199	77.11	1922167	193.9
SCN 0002	CCGT-SUSD-2 - Combined Cycle Gas Turbine 2 - Startup and Shutdown	23		199	77.11	1922167	193.9

Subject Item Groups:

ID	Group Type	Group Description
CRG 0001	Common Requirements Group	ACRN-2 - Acid Rain Requirements
CRG 0002	Common Requirements Group	CSAPR - Cross-State Air Pollution Rule (CSAPR) Requirements
SCN 0001	Alternate Operating Scenario	CCGT-COMM-2 - Combined Cycle Gas Turbine 2 - Commissioning Activities
SCN 0002	Alternate Operating Scenario	CCGT-SUSD-2 - Combined Cycle Gas Turbine 2 - Startup and Shutdown
UNF 0001	Unit or Facility Wide	FW Unit 2 - Facility Wide Unit 2

Group Membership:

Group ID	Group Description	
CRG 0001	ACRN-2 - Acid Rain Requirements	
	EQT ID	**EQT Description**
	EQT 0002	CCGT-2 - Combined Cycle Gas Turbine w/ Duct Burners and HSRG
CRG 0002	CSAPR - Cross-State Air Pollution Rule (CSAPR) Requirements	
	EQT ID	**EQT Description**
	EQT 0001	BOIL-2 - Auxiliary Boiler
	EQT 0002	CCGT-2 - Combined Cycle Gas Turbine w/ Duct Burners and HSRG
	EQT 0003	EGEN-2 - Emergency Diesel Generator
	EQT 0004	FWP-2 - Emergency Diesel Fire Water Pump
	EQT 0005	TK-6 - Atmospheric Drains Tank
	EQT 0006	CB-2 - Circuit Breakers

INVENTORIES

AI ID: 246887 - Camellia Power LLC - Unit 2
Activity Number: PER20240001
Permit Number: 1280-00300-V0
Air - Title V Regular Permit Initial

Group Membership:

Group ID	Group Description	
CRG 0002	CSAPR - Cross-State Air Pollution Rule (CSAPR) Requirements	
	EQT ID	**EQT Description**
	FUG 0001	FUG-2 - Unit 2 Fugitive Emissions
SCN 0001	CCGT-COMM-2 - Combined Cycle Gas Turbine 2 - Commissioning Activities	
	EQT ID	**EQT Description**
	EQT 0002	CCGT-2 - Combined Cycle Gas Turbine w/ Duct Burners and HSRG
SCN 0002	CCGT-SUSD-2 - Combined Cycle Gas Turbine 2 - Startup and Shutdown	
	EQT ID	**EQT Description**
	EQT 0002	CCGT-2 - Combined Cycle Gas Turbine w/ Duct Burners and HSRG

NOTE: The UNF group relationship is not printed in this table. Every subject item is a member of the UNF group.

Annual Maintenance Fee:

Fee Number	Air Contaminant Source	Multiplier	Units of Measure
1420	1420 C) Electric Power Gen. (Natural Gas Fired) (Rated Capacity)	730	MW

EMISSION RATES FOR CRITERIA POLLUTANTS AND CO2e

AI ID: 246887 - Camellia Power LLC - Unit 2
Activity Number: PER20240001
Permit Number: 1280-00300-V0
Air - Title V Regular Permit Initial

All Phases
Facility Wide Unit 2

	CO2e			PM 10			PM 2.5			SO2		
Subject Item	**Avg lb/hr**	**Max lb/hr**	**Tons/Year**	**Avg lb/hr**	**Max lb/hr**	**Tons/Year**	**Avg lb/hr**	**Max lb/hr**	**Tons/Year**	**Avg lb/hr**	**Max lb/hr**	**Tons/Year**
EQT 0001 BOIL-2			41,031.00	0.59	0.59	2.60	0.59	0.59	2.60	0.14	0.14	0.61
EQT 0002 CCGT-2				29.35	29.35	128.55	29.35	29.35	128.55	8.56	9.11	37.49
EQT 0003 EGEN-2			168.00	0.97	0.97	0.05	0.97	0.97	0.05	0.03	0.03	<0.01
EQT 0004 FWP-2			20.00	0.12	0.12	0.01	0.12	0.12	0.01	0.004	0.004	<0.01
EQT 0005 TK-6												
EQT 0006 CB-2			85.00									
FUG 0001 FUG-2			104.00									
SCN 0001 CCGT-COMM-2			72,595.00			3.90			3.90			1.08
SCN 0002 CCGT-SUSD-2			18,455.00		27.43			27.43			3.46	

Note: Emission rates associated with alternate operating scenarios (SCN) are not included in permitted totals unless otherwise noted in a footnote.

EMISSION RATES FOR CRITERIA POLLUTANTS AND CO2e

AI ID: 246887 - Camellia Power LLC - Unit 2
Activity Number: PER20240001
Permit Number: 1280-00300-V0
Air - Title V Regular Permit Initial

All Phases
Facility Wide Unit 2

Subject Item	NOx			CO			VOC		
	Avg lb/hr	Max lb/hr	Tons/Year	Avg lb/hr	Max lb/hr	Tons/Year	Avg lb/hr	Max lb/hr	Tons/Year
EQT 0001 BOIL-2	0.80	0.80	3.50	4.00	4.00	17.52	0.43	0.43	1.88
EQT 0002 CCGT-2	39.12	47.07	171.33	51.35	73.94	224.92	22.28	30.22	97.59
EQT 0003 EGEN-2	30.93	30.93	1.55	16.91	16.91	0.85	30.93	30.93	1.55
EQT 0004 FWP-2	2.34	2.34	0.12	2.04	2.04	0.10	2.34	2.34	0.12
EQT 0005 TK-6							0.01		0.05
EQT 0006 CB-2									
FUG 0001 FUG-2									
SCN 0001 CCGT-COMM-2			85.70			1,469.97			305.41
SCN 0002 CCGT-SUSD-2		385.71			2,800.00			950.00	

EMISSION RATES FOR TAP/HAP & OTHER POLLUTANTS

AI ID: 246887 - Camellia Power LLC - Unit 2

Activity Number: PER20240001

Permit Number: 1280-00300-V0

Air - Title V Regular Permit Initial

All phases

Subject Item	Pollutant	Avg lb/hr	Max lb/hr	Tons/Year
EQT 0001 BOIL-2	Benzene	<0.001	<0.001	<0.01
	Chromium VI (and compounds)	<0.001	<0.001	<0.001
	Formaldehyde	0.01	0.01	0.03
	n-Hexane	0.14	0.14	0.62
	Nickel (and compounds)	<0.001	<0.001	<0.001
	Toluene	<0.001	<0.001	<0.01
	Zinc (and compounds)	0.002	0.002	<0.01
EQT 0002 CCGT-2	1,3-Butadiene	0.002	0.002	0.010
	Acetaldehyde	0.20	0.21	0.85
	Acrolein	0.031	0.033	0.140
	Ammonia	33.20	35.34	145.40
	Barium (and compounds)	0.002	0.003	0.010
	Benzene	0.06	0.06	0.26
	Cadmium (and compounds)	0.001	0.001	0.003
	Chromium VI (and compounds)	0.001	0.001	0.003
	Copper (and compounds)	<0.001	0.001	0.002
	Dichlorobenzene	0.001	0.001	<0.01
	Ethyl benzene	0.16	0.17	0.68
	Formaldehyde	1.07	1.13	4.67
	Manganese (and compounds)	<0.001	<0.001	<0.01
	Mercury (and compounds)	<0.001	<0.001	0.001
	n-Hexane	0.97	1.16	4.23
	Naphthalene	0.01	0.01	0.03
	Nickel (and compounds)	0.001	0.001	0.005
	Polynuclear Aromatic Hydrocarbons	0.011	0.011	0.050
	Propylene oxide	0.14	0.15	0.62
	Sulfuric acid	5.80	6.20	25.40
	Toluene	0.63	0.68	2.78
	Xylene (mixed isomers)	0.31	0.33	1.36
	Zinc (and compounds)	0.02	0.02	0.07
EQT 0003 EGEN-2	Benzene	0.02	0.02	<0.01
FUG 0001 FUG-2	Ammonia	0.03		0.14
SCN 0001 CCGT-COMM-2	**Acetaldehyde**			**0.02**
	Acrolein			**0.004**
	Benzene			**0.01**
	Ethyl benzene			**0.02**
	Formaldehyde			**0.44**
	Naphthalene (and Methyl naphthalenes)			**<0.01**
	Polynuclear Aromatic Hydrocarbons			**0.001**
	Propylene oxide			**0.02**
	Toluene			**0.08**
	Xylene (mixed isomers)			**0.04**
SCN 0002 CCGT-SUSD-2	**Sulfuric acid**		**2.34**	
UNF 0001 FW Unit 2	1,3-Butadiene			0.01
	Acetaldehyde			0.85
	Acrolein			0.14

EMISSION RATES FOR TAP/HAP & OTHER POLLUTANTS

AI ID: 246887 - Camellia Power LLC - Unit 2

Activity Number: PER20240001

Permit Number: 1280-00300-V0

Air - Title V Regular Permit Initial

All phases

Subject Item	Pollutant	Avg lb/hr	Max lb/hr	Tons/Year
	Ammonia			145.54
	Barium (and compounds)			0.01
	Benzene			0.28
	Cadmium (and compounds)			0.003
	Chromium VI (and compounds)			0.004
	Copper (and compounds)			0.002
	Dichlorobenzene			0.01
	Ethyl benzene			0.68
	Formaldehyde			4.70
	Manganese (and compounds)			0.01
	Mercury (and compounds)			0.001
	n-Hexane			4.85
	Naphthalene			0.03
	Nickel (and compounds)			0.006
	Polynuclear Aromatic Hydrocarbons			0.05
	Propylene oxide			0.62
	Sulfuric acid			25.40
	Toluene			2.78
	Xylene (mixed isomers)			1.36
	Zinc (and compounds)			0.08

Note: Emission rates associated with alternate operating scenarios (SCN) are not included in permitted totals unless otherwise noted in a footnote.

Emission rates attributed to the UNF reflect the sum of the TAP/HAP limits of the individual emission points (or caps) under this permit, but do not constitute an emission cap.

For Part 70 sources, the pound per hour and ton per year emission limits established in this "Emission Rates for TAP/HAP & Other Pollutants" section of the permit are state-only unless otherwise noted.

CRG 0001 ACRN-2 - Acid Rain Requirements

Group Members: EQT 2

1 [40 CFR 72.9(a)(1)]	The designated representative shall submit a complete Acid Rain permit application (including a compliance plan) in accordance with the deadlines specified in 40 CFR 72.30, a complete reduced utilization plan if required under 40 CFR 72.43, and any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit. [40 CFR 72.9(a)(1), LAC 33:III.505]
2 [40 CFR 72.9(a)(2)]	Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority, and have an Acid Rain Permit. [40 CFR 72.9(a)(2), LAC 33:III.505]
3 [40 CFR 72.9(b)]	Comply with the monitoring requirements as provided in 40 CFR 75. [40 CFR 72.9(b), LAC 33:III.505]
4 [40 CFR 72.9(c)(1)]	The owners and operators shall hold allowances, as of the allowance transfer deadline, in the source's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the source and comply with the applicable Acid Rain emissions limitation for sulfur dioxide. [40 CFR 72.9(c)(1), LAC 33:III.505]
5 [40 CFR 72.9(c)(5)]	An allowance shall not be deducted, in order to comply with the requirements under 40 CFR 72.9(c)(1)(i), prior to the calendar year for which the allowance was allocated. [40 CFR 72.9(c)(5), LAC 33:III.505]
6 [40 CFR 72.9(e)(1)]	The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR 77. [40 CFR 72.9(e)(1), LAC 33:III.505]
7 [40 CFR 72.9(e)(2)]	The owners and operators of an affected source that has excess emissions in any calendar year shall pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR 77, and comply with the terms of an approved offset plan, as required by 40 CFR 77. [40 CFR 72.9(e)(2), LAC 33:III.505]
8 [40 CFR 72.9(f)(1)]	Keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority. 1.) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24, provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative. 2.) All emissions monitoring information, in accordance with 40 CFR 75, provided that to the extent that part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply. 3.) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program. 4.) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program. [40 CFR 72.9(f)(1), LAC 33:III.505]
9 [40 CFR 72.9(f)(2)]	The designated representative shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 75 and Subpart I of 40 CFR 72. [40 CFR 72.9(f)(2), LAC 33:III.505]
10 [40 CFR 75.10(a)(2)]	To determine NOX emissions, install, certify, operate, and maintain in accordance with all the requirements of 40 CFR 75 a NOX-diluent continuous emission monitoring system (consisting of a NOX pollutant concentration monitor and an O2 or CO2 diluent gas monitor) with an automated data acquisition and handling system for measuring and recording NOX concentration (in ppm), O2 or CO2 concentration (in percent O2 or CO2), and NOX emission rate (in lb/mmBtu) discharged to the atmosphere, except as provided in 40 CFR 75.12 and 75.17 and subpart E of 40 CFR 75. The owner or operator shall account for total NOX emissions, both NO and NO2, either by monitoring for both NO and NO2 or by monitoring for NO only and adjusting the emissions data to account for NO2. [40 CFR 75.10(a)(2)]
11 [40 CFR 75.10(a)(3)]	Determine CO2 emissions by using one of the options in 40 CFR 75.10(a)(3)(i), (ii), or (iii), except as provided in 40 CFR 75.13 and subpart E of 40 CFR 75. [40 CFR 75.10(a)(3)]

CRG 0001 ACRN-2 - Acid Rain Requirements

Group Members: EQT 2

12 [40 CFR 75.10(b)]	The owner or operator shall ensure that each continuous emission monitoring system meets the equipment, installation, and performance specifications in appendix A to 40 CFR 75; and is maintained according to the quality assurance and quality control procedures in appendix B to 40 CFR 75; and shall record SO2 and NOX emissions in the appropriate units of measurement (i.e., lb/hr for SO2 and lb/MM Btu for NOX). [40 CFR 75.10(b)]
13 [40 CFR 75.10(c)]	The owner or operator shall determine and record the heat input rate, in units of MM Btu/hr, to each affected unit for every hour or part of an hour any fuel is combusted following the procedures in appendix F to 40 CFR 75. [40 CFR 75.10(c)]
14 [40 CFR 75.10(d)]	The owner or operator shall ensure that all continuous emission and opacity monitoring systems are in operation and monitoring unit emissions or opacity at all times that the affected unit combusts any fuel except as provided in 40 CFR 75.11(e) and during periods of calibration, quality assurance, or preventive maintenance, performed pursuant to 40 CFR 75.21 and appendix B of 40 CFR 75, periods of repair, periods of backups of data from the data acquisition and handling system, or recertification performed pursuant to 40 CFR 75.20. The owner or operator shall also ensure, subject to the aforementioned exceptions, that all continuous opacity monitoring systems are in operation and monitoring opacity during the time following combustion when fans are still operating, unless fan operation is not required to be included under any other applicable Federal or State regulation, or permit. The owner or operator shall ensure that the requirements of 40 CFR 75.10(d)(1), (2), and (3), as applicable, are met. [40 CFR 75.10(d)]
15 [40 CFR 75.10(f)]	The owner or operator shall ensure that each continuous emission monitoring system is capable of accurately measuring, recording, and reporting data, and shall not incur an exceedance of the full scale range, except as provided in sections 2.1.1.5, 2.1.2.5, and 2.1.4.3 of appendix A to 40 CFR 75. [40 CFR 75.10(f)]
16 [40 CFR 75.10(g)]	The owner or operator shall record and the designated representative shall report the hourly, daily, quarterly, and annual information collected under the requirements of 40 CFR 75 as specified in subparts F and G of 40 CFR 75. [40 CFR 75.10(g)]
17 [40 CFR 75.11(d)(2)]	Measure and record SO2 emissions by providing information satisfactory to the Administrator using the applicable procedures specified in appendix D to 40 CFR 75 for estimating hourly SO2 mass emissions. [40 CFR 75.11(d)(2)]
18 [40 CFR 75.]	Comply with the applicable provisions of Subpart C-Operation and Maintenance Requirements, Subpart D-Missing Data Substitution Procedures, Subpart F-Recordkeeping Requirements, and Subpart G-Reporting Requirements.

CRG 0002 CSAPR - Cross-State Air Pollution Rule (CSAPR) Requirements

Group Members: EQT 1 EQT 2 EQT 3 EQT 4 EQT 5 EQT 6 FUG 1

19 [40 CFR 97.806(a)]	Comply with the requirement to have a designated representative, in accordance with 40 CFR 97.813 through 97.818. The facility may have an alternate designated representative, in accordance with 40 CFR 97.813 through 97.818. Subpart EEEEE. [40 CFR 97.806(a)]
20 [40 CFR 97.806(b)(1)]	Comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.830 through 97.835. Subpart EEEEE. [40 CFR 97.806(b)(1)]
21 [40 CFR 97.806(b)(2)]	Use the emissions data determined in accordance with 40 CFR 97.830 through 97.835 to calculate allocations of CSAPR NOx Ozone Season Group 2 allowances under 40 CFR 97.811(a)(2) and (b) and 40 CFR 97.812 and to determine compliance with the CSAPR NOx Ozone Season Group 2 emissions limitation and assurance provisions under 40 CFR 97.806(c), provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating the allocations and determining the compliance is the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero. Subpart EEEEE. [40 CFR 97.806(b)(2)]

CRG 0002 CSAPR - Cross-State Air Pollution Rule (CSAPR) Requirements

Group Members: EQT 1 EQT 2 EQT 3 EQT 4 EQT 5 EQT 6 FUG 1

22 [40 CFR 97.806(c)(1)(i)]	As of the allowance transfer deadline for a control period in a given year, hold, in the source's compliance account, CSAPR NOx Ozone Season Group 2 allowances available for deduction for the control period under 40 CFR 97.824(a) in an amount not less than the tons of total NOx emissions for the control period from all CSAPR NOx Ozone Season Group 2 units at the source. Subpart EEEEE. [40 CFR 97.806(c)(1)(i)]
23 [40 CFR 97.806(c)(1)(ii)(A)]	Hold the CSAPR NOx Ozone Season Group 2 allowances required for deduction under 40 CFR 97.824(d), if total NOx emissions during a control period in a given year from the CSAPR NOx Ozone Season Group 2 units at a CSAPR NOx Ozone Season Group 2 source are in excess of the CSAPR NOx Ozone Season Group 2 emissions limitations set forth in 40 CFR 97.806(c)(1)(i). Subpart EEEEE. [40 CFR 97.806(c)(1)(ii)(A)]
24 [40 CFR 97.806(c)(1)(ii)(B)]	Pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act, if total NOx emissions during a control period in a given year from the CSAPR NOx Ozone Season Group 2 units at a CSAPR NOx Ozone Season Group 2 source are in excess of the CSAPR NOx Ozone Season Group 2 emissions limitations set forth in 40 CFR 97.806(c)(1)(i). Consider each ton of the excess emissions and each day of the control period to constitute a separate violation of 40 CFR 97 Subpart EEEEE and the Clean Air Act. Subpart EEEEE. [40 CFR 97.806(c)(1)(ii)(B)]
25 [40 CFR 97.806(c)(2)(i)]	If total NOx emissions during a control period in a given year from all base CSAPR NOx Ozone Season Group 2 units at base CSAPR NOx Ozone Season Group 2 sources in a State (and Indian country within the borders of the State) exceed the State assurance level, hold (in the assurance account established for the owners and operators of the facility's group) CSAPR NOx Ozone Season Group 2 allowances available for deduction for the control period under 40 CFR 97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by DEQ in accordance with 40 CFR 97.825(b), of multiplying the quotient specified in 40 CFR 97.806(c)(2)(i)(A) and amount specified in 40 CFR 97.806(c)(2)(i)(B). Subpart EEEEE. [40 CFR 97.806(c)(2)(i)]
26 [40 CFR 97.806(c)(2)(ii)]	Hold the CSAPR NOx Ozone Season Group 2 allowances required under 40 CFR 97.806(c)(2)(i), as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after the year of such control period. Subpart EEEEE. [40 CFR 97.806(c)(2)(ii)]
27 [40 CFR 97.806(c)(2)(iii)]	Consider the total NOx emissions from all base CSAPR NOx Ozone Season Group 2 units at base CSAPR NOx Ozone Season Group 2 sources in a State (and Indian country within the borders of the State) during a control period in a given year to exceed State assurance level if the total NOx emissions exceed the sum, for the control period, of the State NOx Ozone Season Group 2 trading budget under 40 CFR 97.810(a) and the State's variability under 40 CFR 97.810(b). Subpart EEEEE. [40 CFR 97.806(c)(2)(iii)]
28 [40 CFR 97.806(c)(2)(v)]	Pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act, to the extend that CSAPR NOx Ozone Season Group 2 allowances were not held for a control period in a given year in accordance with 40 CFR 97.806(c)(2)(i) through (c)(2)(iii). Consider each CSAPR NOx Ozone Season Group 2 allowance that was not held for the control period in accordance with 40 CFR 97.806(c)(2)(i) through (c)(2)(iii) and each day of the control period to constitute a separate violation of 40 CFR 97 Subpart EEEEE and the Clean Air Act. Subpart EEEEE. [40 CFR 97.806(c)(2)(v)]
29 [40 CFR 97.806(c)(3)(i)]	Ensure that each CSAPR NOx Ozone Season Group 2 unit complies with the requirements under 40 CFR 97.806(c)(1) for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter. Subpart EEEEE. [40 CFR 97.806(c)(3)(i)]
30 [40 CFR 97.806(c)(3)(ii)]	Ensure that each base CSAPR NOx Ozone Season Group 2 unit complies with the requirements under 40 CFR 97.806(c)(2) for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter. Subpart EEEEE. [40 CFR 97.806(c)(3)(ii)]

CRG 0002 CSAPR - Cross-State Air Pollution Rule (CSAPR) Requirements

Group Members: EQT 1 EQT 2 EQT 3 EQT 4 EQT 5 EQT 6 FUG 1

31 [40 CFR 97.806(c)(4)(i)]	Ensure that a CSAPR NOx Ozone Season Group 2 allowance held for compliance with the requirements under 40 CFR 97.806(c)(1)(i) for a control period in a given year is a CSAPR NOx Ozone Season Group 2 allowance that was allocated or auctioned for the control period or a control period in a prior year. Subpart EEEEE. [40 CFR 97.806(c)(4)(i)]
32 [40 CFR 97.806(c)(4)(ii)]	Ensure that a CSAPR NOx Ozone Season Group 2 allowance held for compliance with the requirements under 40 CFR 97.806(c)(1)(ii)(A) and (c)(2)(i) through (c)(2)(iii) for a control period in a given year is a CSAPR NOx Ozone Season Group 2 allowance that was allocated or auctioned for a control period in a prior year or the control period in the given year or in the immediately following year. Subpart EEEEE. [40 CFR 97.806(c)(4)(ii)]
33 [40 CFR 97.806(c)(5)]	Ensure that each CSAPR NOx Ozone Season Group 2 allowance is held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR 97 Subpart EEEEE. Subpart EEEEE. [40 CFR 97.806(c)(5)]
34 [40 CFR 97.806(c)(6)]	CSAPR NOx Ozone Season Group 2 allowance: Limit emissions to one ton of NOx during the control period in one year. Use the CSAPR NOx Ozone Season Group 2 allowance only in accordance with CSAPR NOx Ozone Season Group 2 Trading Program. Subpart EEEEE. [40 CFR 97.806(c)(6)]
35 [40 CFR 97.806(c)(7)]	Do not consider a CSAPR NOx Season Group 2 allowance to constitute a property right. Subpart EEEEE. [40 CFR 97.806(c)(7)]
36 [40 CFR 97.806(e)(1)]	Keep on site at the source the documents specified in 40 CFR 97.806(e)(1)(i) through (e)(1)(iii) (in hardcopy or electronic format) for a period of 5 years from the date the document is created, unless otherwise provided. Subpart EEEEE. [40 CFR 97.806(e)(1)]
37 [40 CFR 97.806(e)(2)]	Make all submissions required under the CSAPR NOx Ozone Season Group 2 Trading Program, except as provided in 40 CFR 97.818. Subpart EEEEE. [40 CFR 97.806(e)(2)]
38 [40 CFR 97.806(f)]	Comply with any provision of the CSAPR NOx Ozone Season Group 2 Trading Program that applies to a CSAPR NOx Ozone Season Group 2 source or the designated representative of a CSAPR NOx Ozone Season Group 2 source. Subpart EEEEE. [40 CFR 97.806(f)]
39 [40 CFR 97.816(a)]	Complete a certificate of representation for a designated representative that includes the elements specified in 40 CFR 97.816(a)(1) through (a)(5) in a format prescribed by DEQ. Comply with this requirement for any alternate designated representative also. Subpart EEEEE. [40 CFR 97.816(a)]
40 [40 CFR 97.830(a)]	Install all monitoring systems required under 40 CFR 97 Subpart EEEEE for monitoring NOx mass emissions and individual unit heat input (including all systems required to monitor NOx emission rate, NOx concentration, stack gas moisture content, stack gas flow rate, CO2 or O2 concentration, and fuel flow rate, as application, in accordance with 40 CFR 75.71 and 40 CFR 75.72). Successfully complete all certification tests required under 40 CFR 97.831 and meet all other requirements of 40 CFR 97 Subpart EEEEE and 40 CFR 75 applicable to the monitoring systems under 40 CFR 97.830(a)(1). Record, report, and quality-assure the data from the monitoring systems under 40 CFR 97.830(a)(1). Subpart EEEEE. [40 CFR 97.830(a)]
41 [40 CFR 97.830(b)]	Meet the monitoring system certification and other requirements of 40 CFR 97.830(a)(1) and (a)(2) on or before the latest of the dates specified in 40 CFR 97.830(b)(1) through (b)(4), and record, report, and quality-assure the data from the monitoring systems under 40 CFR 97.830(a)(1) on and after the latest of the dates specified in 40 CFR 97.830(b)(1) through (b)(4), except as provided in 40 CFR 97.830(e). Subpart EEEEE. [40 CFR 97.830(b)]
42 [40 CFR 97.830(c)]	Determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NOx concentration, NOx emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NOx mass emissions and heat input in accordance with 40 CFR 75.31(b)(2) or (c)(3), 40 CFR 75, Appendix D, Section 2.4, or 40 CFR 75, Appendix E, Section 2.5, as applicable, for each monitoring system under 40 CFR 97.830(a)(1) that does not meet the applicable compliance date set forth in 40 CFR 97.830(b). Subpart EEEEE. [40 CFR 97.830(c)]

CRG 0002 CSAPR - Cross-State Air Pollution Rule (CSAPR) Requirements

Group Members: EQT 1 EQT 2 EQT 3 EQT 4 EQT 5 EQT 6 FUG 1

43 [40 CFR 97.834(a)]	Comply with all recordkeeping and reporting requirements in 40 CFR 97.834(b) through (e), the applicable recordkeeping and reporting requirements under 40 CFR 75.73, and the requirements of 40 CFR 97.814(a). Subpart EEEEE. [40 CFR 97.834(a)]
44 [40 CFR 97.834(b)]	Comply with the requirements of 40 CFR 75.73(c) and (e). Subpart EEEEE. [40 CFR 97.834(b)]
45 [40 CFR 97.834(c)]	Submit application: Due to DEQ within 45 days after completing all initial certification or recertification tests required under 40 CFR 97.831. Include the information required under 40 CFR 75.63. Subpart EEEEE. [40 CFR 97.834(c)]
46 [40 CFR 97.834(d)(1)(i)]	Meet the requirements of 40 CFR 75 Subpart H (concerning monitoring of NOx mass emissions) for the unit for the entire year and report the NOx mass emissions data and heat input data for the unit for the entire year, if a CSAPR NOx Ozone Season Group 2 unit is subject to the Acid Rain Program or CSAPR NOx Annual Trading Program or if the owner or operator of the unit chooses to report on an annual basis under 40 CFR 97 Subpart EEEEE. Subpart EEEEE. [40 CFR 97.834(d)(1)(i)]
47 [40 CFR 97.834(e)]	Submit to DEQ a compliance certification (in a format prescribed by DEQ) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. Include the information specified in 40 CFR 97.834(e)(1) through (e)(3). Subpart EEEEE. [40 CFR 97.834(e)]

EQT 0001 BOIL-2 - Auxiliary Boiler

48 [40 CFR 60.48c(a)]	Submit notification: Due as specified in 40 CFR 60.7. Submit the date of construction or reconstruction and actual startup. Include the information specified in 40 CFR 60.48c(a)(1) through (a)(4) as applicable. Subpart Dc. [40 CFR 60.48c(a)]
49 [40 CFR 60.48c(g)(2)]	Fuel rate recordkeeping by electronic or hard copy monthly. Keep records of the amount of each fuel combusted during each calendar month. Subpart Dc. [40 CFR 60.48c(g)(2)]
50 [40 CFR 60.48c(i)]	Maintain all records required under 40 CFR 60.48c for a period of 2 years following the date of such record. Subpart Dc. [40 CFR 60.48c (i)]
51 [40 CFR 63.7500(a)(1)]	Conduct a tune-up every 5 years as specified in 40 CFR 63.7540. Subpart DDDDD. [40 CFR 63.7500(a)(1), 40 CFR 63.7530(h), 40 CFR 63.7540(a)(12)]
52 [40 CFR 63.7500(a)(3)]	Operate and maintain at all times any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Subpart DDDDD. [40 CFR 63.7500(a)(3)]
53 [40 CFR 63.7505(a)]	Be in compliance with the emission limits, work practice standards, and operating limits in 40 CFR 63 Subpart DDDDD at all times the affected unit is operating except for the periods noted in 40 CFR 63.7500(f). Subpart DDDDD. [40 CFR 63.7505(a)]
54 [40 CFR 63.7515(d)]	Conduct an annual, biennial, or 5-year performance tune-up according to 40 CFR 63.7540(a)(10), (a)(11), or (a)(12), respectively, if required to meet an applicable tune-up work practice standard. Ensure that each annual tune-up specified in 40 CFR 63.7540(a)(10) is no more than 13 months after the previous tune-up, each biennial tune-up specified in 40 CFR 63.7540(a)(11) is conducted no more than 25 months after the previous tune-up, and each 5-year tune-up specified in 40 CFR 63.7540(a)(12) is conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in 40 CFR 63.7490), ensure that the first annual, biennial, or 5-year tune-up is no later than 13 months, 25 months, or 61 months, respectively, after the initial startup of the new or reconstructed affected source. Subpart DDDDD. [40 CFR 63.7515(d)]
55 [40 CFR 63.7540(a)(13)]	Conduct the tune-up within 30 calendar days of startup, if the unit is not operating on the required date for a tune-up. Subpart DDDDD. [40 CFR 63.7540(a)(13)]
56 [40 CFR 63.7545(a)]	Submit to DEQ all of the applicable notifications in 40 CFR 63.7(b) and (c), 40 CFR 63.8(e), (f)(4) and (f)(6), and 40 CFR 63.9(b) through (h) by the dates specified. Subpart DDDDD. [40 CFR 63.7545(a)]

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57 [40 CFR 63.7545(c)]	Submit Initial Notification: Due to DEQ not later than 15 days after the actual date of startup of the affected source, as specified in 40 CFR 63.9(b)(4) and (b)(5). Subpart DDDDD. [40 CFR 63.7545(c)]
58 [40 CFR 63.7550(h)(3)]	Submit all reports required by 40 CFR 63 Subpart DDDDD, Table 9 electronically to the EPA via the CEDRI. (CEDRI is accessed through the EPA's Central Data Exchange (CDX).) Use the appropriate electronic report in CEDRI for 40 CFR 63 Subpart DDDDD. An alternate electronic file consistent with the XML schema listed on the CEDRI Web site (https://www.epa.gov/chief/) may be submitted once the XML schema is available, instead of using the electronic report in CEDRI for 40 CFR 63 Subpart DDDDD. Submit the report to the EPA at the appropriate address listed in 40 CFR 63.13, if the reporting form specific to 40 CFR 63 Subpart DDDDD is not available in CEDRI at the time that the report is due. Begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. Subpart DDDDD. [40 CFR 63.7550(h)(3)]
59 [40 CFR 63.7550]	Submit compliance status report: Due Date of Submittal once every 5 years on January 31 covering the previous 5-year period (January 1 of the first year to December 31 of the fifth year), according to the requirements in 40 CFR 63.7550(b). Submit the information specified in 40 CFR 63.7550(c)(1) through (c)(5), as applicable. Include the information specified in 40 CFR 63.7550(d)(1) through (d)(3) for each deviation from an emission limit or operating limit in 40 CFR 63 Subpart DDDDD that occurs where a CMS is not being used to comply with that emission limit or operating limit and/or for each deviation from the work practice standards for periods of startup and shutdown. Include the information in 40 CFR 63.7550(e)(1) through (e)(9) for each deviation from an emission limit, operating limit, and monitoring requirement in 4 CFR 63 Subpart DDDDD that occurs where a CMS is being used to comply with that emission limit or operating limit. Subpart DDDDD. [40 CFR 63.7540(b), 40 CFR 63.7550]
60 [40 CFR 63.7555]	Equipment/operational data recordkeeping by electronic or hard copy at the regulation's specified frequency. Keep records of the information specified in 40 CFR 63.7555(a) through (h), as applicable. Subpart DDDDD.
61 [40 CFR 63.7560(a)]	Keep records in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). Subpart DDDDD. [40 CFR 63.7560(a)]
62 [40 CFR 63.7560(b)]	Keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record, as specified in 4 CFR 63.10(b)(1). Subpart DDDDD. [40 CFR 63.7560(b)]
63 [40 CFR 63.7560(c)]	Keep each record on site, or ensure that they are accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). The remaining 3 years may be kept offsite. Subpart DDDDD. [40 CFR 63.7560(c)]
64 [LAC 33:III.1313.C]	Total suspended particulate <= 0.6 lb/MMBTU of heat input (Complies by using sweet natural gas as fuel). Which Months: All Year Statistical Basis: None specified
65 [LAC 33:III.509]	CO2e <= 117 lb/MMBTU CO2e BACT shall be energy efficient design, use of gaseous fuel, good combustion practices, and compliance with 40 CFR 63 Subpart DDDDD. CO2e operating limits are based on an annual average during normal operations.
66 [LAC 33:III.509]	Carbon monoxide (CO) <= 0.05 lb/MMBTU. CO BACT shall be good combustion practices and compliance with 40 CFR 63 Subpart DDDDD. CO operating limits are based on an annual average during normal operations.
67 [LAC 33:III.509]	Nitrogen oxides (NOx) <= 0.01 lb/MMBTU. NOx BACT shall be the use of ultra-low NOx burners and good combustion practices. NOx operating limits are based on an annual average during normal operations.
68 [LAC 33:III.509]	Particulate matter (10 microns or less) (PM10) <= 0.0074 lb/MMBTU. PM10 BACT: Use of natural gas and good combustion practices. PM10 operating limits are based on an annual average during normal operations.
69 [LAC 33:III.509]	Particulate matter (2.5 microns or less) (PM2.5) <= 0.0074 lb/MMBTU. PM2.5 BACT: Use of natural gas and good combustion practices. PM2.5 operating limits are based on an annual average during normal operations.
70 [LAC 33:III.509]	VOC, Total <= 0.0054 lb/MMBtu. VOC BACT shall be good combustion practices and compliance with 40 CFR 63 Subpart DDDDD. VOC operating limits are based on an annual average during normal operations.

EQT 0002 CCGT-2 - Combined Cycle Gas Turbine w/ Duct Burners and HSRG

71 [40 CFR 60.4320(a)]	Nitrogen oxides (NOx) <= 15 ppm @ 15%O2. Subpart KKKK. [40 CFR 60.4320(a)] Which Months: All Year Statistical Basis: Thirty-day rolling average
72 [40 CFR 60.4320(a)]	Nitrogen oxides (NOx) <= 96 ppm @ 15%O2 when operating at <75% peak load. Subpart KKKK. [40 CFR 60.4320(a)] Which Months: All Year Statistical Basis: Thirty-day rolling average
73 [40 CFR 60.4330(a)(2)]	Sulfur dioxide (SO2) <= 0.060 lb/MMBTU (26 ng/J) heat input. If the turbine simultaneously fires multiple fuels, each fuel must meet this requirement. Subpart KKKK. [40 CFR 60.4330(a)(2)] Which Months: All Year Statistical Basis: None specified
74 [40 CFR 60.4333(a)]	Operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction. Subpart KKKK. [40 CFR 60.4333(a)]
75 [40 CFR 60.4340(b)(1)]	Nitrogen Oxides monitored by continuous emission monitor (CEM) continuously as described in 40 CFR 60.4335(b) and 40 CFR 60.4345. Subpart KKKK. [40 CFR 60.4340(b)(1)] Which Months: All Year Statistical Basis: None specified
76 [40 CFR 60.4350]	Use data from the continuous emission monitoring equipment to identify excess emissions in accordance with 40 CFR 60.4350.
77 [40 CFR 60.4365]	Sulfur dioxide (SO2) <= 0.060 lb/MMBTU (26 ng/J). Use one of the sources of information specified in 40 CFR 60.4365(a) and (b) to make the required demonstration. Subpart KKKK. Which Months: All Year Statistical Basis: None specified
78 [40 CFR 60.4375(a)]	Submit excess emissions reports and monitor downtime, in accordance with 40 CFR 60.7(c). Report excess emissions for all periods of unit operation, including start-up, shutdown, and malfunction. Subpart KKKK. [40 CFR 60.4375(a)]
79 [40 CFR 60.4380(b)(3)]	For operating periods during which multiple standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emission standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard. [40 CFR 60.4380(b)(3)]
80 [40 CFR 60.4395]	Postmark the excess emissions report required under 40 CFR 60.7(c) by the 30th day following the end of each 6-month period. Subpart KKKK.
81 [40 CFR 60.4400]	Conduct an initial performance test for NOx, as required in 40 CFR 60.8. Use one of methodologies specified in 40 CFR 60.4400(a)(1)(i) and (a)(1)(ii). If using a NOx-diluent CEMS according to 40 CFR 60.4345, then the test may be performed as specified in 40 CFR 60.4405 (a) through (d). Subpart KKKK.
82 [40 CFR 60.4415]	Conduct performance tests for sulfur initially as required in 40 CFR 60.8 and annually thereafter. Use one of the methodologies specified in 40 CFR 60.4415(a)(1) through (a)(4). Subpart KKKK.
83 [40 CFR 60.5520a]	Carbon dioxide <= 800 lb/MWh -gross energy cutput upon startup (base load emission standard for natural gas-fired combustion turbine with base load ratings greater than 2,000 MMBtu/hr).
84 [40 CFR 60.5525a(a)(1)]	Compliance with the applicable CO2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis. See table 1 of 40 CFR 60 Subpart TTTTa for the applicable CO2 emission standards. You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times. For each affected EGU subject to a CO2 emissions standard based on a 12-operating-month rolling average, you must determine compliance monthly by calculating the average CO2 emissions rate for the affected EGU at the end of the initial and each subsequent 12-operating-month period. [40 CFR 60.5525a(a)(1)]
85 [40 CFR 60.5525a(b)]	At all times you must operate and maintain each affected EGU, including associated equipment and monitors, in a manner consistent with safety and good air pollution control practice. [40 CFR 60.5525a(b)]

EQT 0002 CCGT-2 - Combined Cycle Gas Turbine w/ Duct Burners and HSRG

86 [40 CFR 60.5525a(c)]	Within 30 days after the end of the initial compliance period (i.e., no more than 30 days after the first 12-operating-month compliance period), you must make an initial compliance determination for your affected EGU(s) with respect to the applicable emissions standard in table 1 of 40 CFR 60 Subpart TTTTa, in accordance with the requirements in subpart TTTTa. The first operating month included in the initial 12-operating-month compliance period shall be determined as described in 40 CFR 60.5525a(c)(1) - (3). [40 CFR 60.5525a(c)]
87 [40 CFR 60.5535a(a)]	Prepare a monitoring plan to quantify the hourly CO2 mass emission rate (tons/hr) in accordance with the applicable provisions of 40 CFR 75.53(g) and (h). Determine hourly CO2 mass emissions per the options listed in 40 CFR 60.5535a. [40 CFR 60.5535a(a), 40 CFR 60.5535a(b)]
88 [40 CFR 60.5540a(a)]	Demonstrate compliance with the applicable CO2 emission standard in table 1 to 40 CFR 60 subpart TTTTa as required by 40 CFR 60.5540a. For the initial and each subsequent 12-operating-month rolling average compliance period, you must follow the procedures in paragraphs 40 CFR 60.5540a(a)(1) through (8) to calculate the CO2 mass emissions rate for your affected EGU(s) in units of the applicable emissions standard (e.g., either kg/MWh or kg/GJ). You must use the hourly CO2 mass emissions calculated under 40 CFR 60.5535a(b) or (c), as applicable, and either the generating load data from § 60.5535a(d)(1) for output-based calculations or the heat input data from § 60.5535a(d)(2) for heat-input-based calculations. [40 CFR 60.5540a(a)]
89 [40 CFR 60.5540a(b)]	In accordance with 40 CFR 60.5520a, to demonstrate compliance with the applicable CO2 emission standard, for the initial and each subsequent 12-operating-month compliance period, the CO2 mass emissions rate for your affected EGU must be determined according to the procedures specified in 40 CFR 60.5540a(a)(1) through (8) and must be less than or equal to the applicable CO2 emissions standard in table 1 of 40 CFR 60 Subpart TTTTa, or the emissions standard calculated in accordance with 40 CFR 60.5525a(a)(2). [40 CFR 60.5540a (b)]
90 [40 CFR 60.5550a(a)]	Prepare and submit the notifications specified in 40 CFR 60.7(a)(1) and (3) and 40 CFR 60.19, as applicable to your affected EGU(s) (see table 3 of 40 CFR 60 Subpart TTTTa). [40 CFR 60.5550a(a)]
91 [40 CFR 60.5550a(b)]	Prepare and submit notifications specified in 40 CFR 75.61, as applicable, to your affected EGUs. [40 CFR 60.5550a(b)]
92 [40 CFR 60.5555a]	Submit the reports described in 40 CFR 60.5555a(a) - (d), as applicable.
93 [40 CFR 60.5560a]	Keep records as required per 40 CFR 60.5560a. Subpart TTTTa.
94 [40 CFR 60.5565a]	Records must be in a form suitable and readily available for expeditious review. Maintain each record for 5 years after the date of conclusion of each compliance period. Maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 60.7. Records that are accessible from a central location by a computer or other means that instantly provide access at the site meet this requirement. You may maintain the records off site for the remaining year(s) as required by 40 CFR 60 subpart TTTTa.
95 [40 CFR 60.6135(a)]	Except for monitor malfunctions, associated repairs, and required quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments of the monitoring system), you must conduct all parametric monitoring at all times the stationary combustion turbine is operating. Subpart YYYY. [40 CFR 60.6135(a)]
96 [40 CFR 63.6100]	Formaldehyde <= 91 ppbdv at 15% oxygen, except during turbine startup. Subpart YYYY. Which Months: All Year Statistical Basis: None specified
97 [40 CFR 63.6105(a)]	Comply with the applicable emission limitations, applicable operating limitations, and other applicable requirements in 40 CFR 63 Subpart YYYY at all times. Subpart YYYY. [40 CFR 63.6105(a)]
98 [40 CFR 63.6105(c)]	Operate and maintain the affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Subpart YYYY. [40 CFR 63.6105(c)]

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99 [40 CFR 63.6120]	Conduct an initial performance for formaldehyde as specified in Table 3 of Subpart YYYY within 180 calendar days after startup. Perform subsequent performance tests on an annual basis as specified in Table 3 of Subpart YYYY. Conduct three separate test runs for each performance test, and each test run must last at least 1 hour. Conduct performance tests at high load, defined as 100 percent plus or minus 10 percent. Each performance test must be conducted according to the requirements of Table 3. Subpart YYYY. [40 CFR 63.6110(a), 40 CFR 63.6115, 40 CFR 63.6120]
100 [40 CFR 63.6125(e)]	Develop and implement a continuous monitoring system (CMS) quality control program that includes written procedures for CMS according to 40 CFR 63.8(d)(1) through (d)(2). Keep these written procedures on record for the life of the affected source or until the affected source is no longer subject to the provisions of 40 CFR 63 Subpart YYYY. Make the procedures available for inspection, upon request, by DEQ. Keep previous (i.e. superseded) versions of the performance evaluation plan on record to be made available for inspection, upon request, by DEQ, for a period of 5 years after each revision to the plan, if the performance evaluation plan is revised. Include the program of corrective action in the plan required under 40 CFR 63.8(d)(2). Subpart YYYY. [40 CFR 63.6125(e)]
101 [40 CFR 63.6130(b)]	Submit the Notification of Compliance Status containing results of the initial compliance demonstration according to the requirements in 40 CFR 63.6145(f). Subpart YYYY. [40 CFR 63.6130(b)]
102 [40 CFR 63.6135(b)]	Do not use data recorded during monitor malfunctions, associated repairs, and required quality assurance or quality control activities for meeting the requirements of this subpart, including data averages and calculations. You must use all the data collected during all other periods in assessing the performance of the control device or in assessing emissions from the new or reconstructed stationary combustion turbine. Subpart YYYY. [40 CFR 63.6135(b)]
103 [40 CFR 63.6140(a)]	Continuously monitor and record the inlet temperature to the oxidation catalyst and maintain the 4-hour rolling average of the inlet temperature within the range suggested by the catalyst manufacturer. Do not use the catalyst inlet temperature data that is recorded during engine startup in the calculations of the 4-hour rolling average catalyst inlet temperature. [40 CFR 63.6125(a), 40 CFR 63.6140(a)]
104 [40 CFR 63.6140(b)]	Report each instance in which each emission limitation or operating limitation and any applicable requirements in 40 CFR 63 Subpart YYYY Table 7 were not met according to the requirements in 40 CFR 63.6150. Subpart YYYY. [40 CFR 63.6140(b)]
105 [40 CFR 63.6145(a)]	Submit all of the notifications in 40 CFR 63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) by the dates specified, as applicable. Subpart YYYY. [40 CFR 63.6145(a)]
106 [40 CFR 63.6145(c)]	Submit Initial Notification: Due not later than 120 calendar days after initial startup, as specified in 40 CFR 63.9(b). Subpart YYYY. [40 CFR 63.6145(c)]
107 [40 CFR 63.6145(e)]	Submit Notification: Due at least 60 calendar days before the initial performance test is scheduled to begin as required in 40 CFR 63.7(b)(1), if required to conduct an initial performance test. Subpart YYYY. [40 CFR 63.6145(e)]
108 [40 CFR 63.6145(f)]	Submit Notification of Compliance Status: Due before the close of business on the 60th calendar day following the completion of a performance test. Include the performance test results. Subpart YYYY. [40 CFR 63.6145(f)]
109 [40 CFR 63.6150(f)]	Submit Performance Test Report: Due to EPA within 60 days after the date of completing each performance test required by 40 CFR 63 Subpart YYYY. Submit the results of the performance test (as specified in 40 CFR 63.6145(f)) following the procedures specified in 40 CFR 63.6150(f)(1) through (f)(3). Subpart YYYY. [40 CFR 63.6150(f)]

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110 [40 CFR 63.6150(g)]	If you are required to submit reports following the procedure specified in this paragraph, you must submit reports to the EPA via CEDRI, which can be accessed through the EPA's CDX (https://cdx.epa.gov/). You must use the appropriate electronic report template on the CEDRI website (https://www.epa.gov/electronic-reporting-air-emissions/compliance-and-emissions-data-reporting-interface-cedri) for this subpart. The date report templates become available will be listed on the CEDRI website. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. If you claim some of the information required to be submitted via CEDRI is CBI, submit a complete report, including information claimed to be CBI, to the EPA. The report must be generated using the appropriate form on the CEDRI website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph. Subpart YYYY. [40 CFR 63.6150(g)]
111 [40 CFR 63.6150]	Submit report: Due semiannually that contains the data listed at 40 CFR 63.6150(a)(1) through (5). Comply with the submittal dates listed at 40 CFR 63.6150(b). Subpart YYYY.
112 [40 CFR 63.6155]	Equipment/operational data recordkeeping by electronic or hard copy at the regulation's specified frequency. Keep records of the information specified in 40 CFR 63.6155(a) and (c), as applicable. Maintain in electronic format any records required to be maintained by 40 CFR 63 Subpart YYYY that are submitted electronically via the EPA's CEDRI. Subpart YYYY.
113 [40 CFR 63.6160]	Maintain all applicable records in such a manner that they can be readily accessed and are suitable for inspection according to 40 CFR 63.10(b)(1). Keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. Retain records of the most recent 2 years on site or make records accessible on site. The remaining 3 years may be retained off site. Subpart YYYY.
114 [LAC 33:III.1311.C]	Opacity <= 20 percent, except for emissions that have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes. Which Months: All Year Statistical Basis: Six-minute average
115 [LAC 33:III.1313.C]	Duct burners: Total suspended particulate <= 0.6 lb/MMBTU of heat input (Complies by using sweet natural gas as fuel). Which Months: All Year Statistical Basis: None specified
116 [LAC 33:III.1513.C]	Equipment/operational data recordkeeping by electronic or hard copy once initially and annually. Record and retain at the site sufficient data to show annual potential sulfur dioxide emissions. Comply with the recordkeeping provisions in 40 CFR 75 - Continuous Emission Monitoring.
117 [LAC 33:III.501]	CO_2e <= 2,658,075 tons/yr.
118 [LAC 33:III.507.H.1.a]	Conduct a performance/emissions test: Due under any of the following circumstances: 1. Within 180 days of initial start-up (or restart-up after modification); or within 60 days of achieving normal production or completing shakedown period, whichever is earlier; or 2. Within 180 days of the issuance of this permit, for existing sources that have never conducted a performance/emissions test; or 3. Within 5 years, plus or minus 6 months, from when the previous performance/emissions test was performed. If this source is not operational when a performance/emissions test is due, the test shall be due within 60 days of startup.
119 [LAC 33:III.507.H.1.a]	Operating rate monitored by technically sound method daily. This condition shall not apply if the most recent LDEQ required performance/emissions test was conducted at greater than or equal to 80% of the maximum permitted load. Which Months: All Year Statistical Basis: None specified
120 [LAC 33:III.507.H.1.a]	Operating rate recordkeeping by electronic or hard copy daily. This condition shall not apply if the most recent LDEQ required performance/emissions test was conducted at greater than or equal to 80% of the maximum permitted load.

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121 [LAC 33:III.507.H.1.a]	Submit Notification: Due within 14 days to the Office of Environmental Services if the source is operated at a load that is more than 10 percent higher than the rate at which the most recent LDEQ required performance/emissions test was conducted. Determine the operating load of the source based on a 30 day rolling average. Calculate the increase in operating load as a percentage of the rate at which the most recent performance/emissions test was conducted. Include information identifying the source, the data used to calculate the operating rate during the 30 day rolling average, and a description of the circumstances that caused the source to operate more than 10 percent higher than the rate at which the most recent performance/emissions test was conducted. This condition shall not apply if the most recent LDEQ required performance/emissions test was conducted at greater than or equal to 80% of the maximum permitted load.
122 [LAC 33:III.507.H.1.a]	Submit notification: Due to the Office of Environmental Services at least 30 days prior to any LDEQ required performance/emissions test. Submit notification in order to provide the opportunity to conduct a pretest meeting and observe the emission testing. Submit notification at least 45 days prior to the deadline specified in this permit indicating the reason that the test will not be conducted by the specified deadline, if any LDEQ required performance/emissions test will not be conducted by the deadline specified in this permit. This notification will be evaluated by the department on a case-by-case basis to determine if an extension to the deadline for testing specified in this permit is warranted. The deadline for testing specified in this permit shall remain in effect until the department responds in writing with an extension to this deadline.
123 [LAC 33:III.507.H.1.a]	Submit report: Due within 60 days after performance/emissions test. Submit performance/emissions test results to the Office of Environmental Services. Include any necessary conversion into the units of any applicable standard (lbs/MMBtu, gr/dscf, lbs SO2 / ton 100% H2SO4, etc.). Include plant and in house laboratory data to support production values (example: how many tons of 100% equivalent H2SO4 was being produced).
124 [LAC 33:III.509]	CO2e <= 800 lb/MWh. CO2e BACT: Use of gaseous fuel (pipeline-quality natural gas or a blend of up to 50% H2 and natural gas), thermally efficient turbine, and good combustion practices. Which Months: Phases: Statistical Basis: Twelve-month rolling average (rolling 1-month basis)
125 [LAC 33:III.509]	Carbon monoxide (CO) <= 2.0 ppm @ 15%O2. CO BACT: Use of catalytic oxidation and good combustion practices. Install and utilize a CEMS to monitor CO. Which Months: Phases: Statistical Basis: 24-hour rolling average based on a one-hour average
126 [LAC 33:III.509]	Conduct performance/emissions tests according to the following test methods unless otherwise specified in an applicable state or federal regulation: VOC, 40 CFR 60, Appendix A: Method 25A - Determination of Gaseous Organic Concentration using a Flame Ionization Analyzer; and PM10/PM2.5, 40 CFR 51, Appendix M: Method 201A - Determination of PM10 and PM2.5 Emissions from Stationary Sources (Constant Sampling Rate Procedure) and Method 202- Dry Impinger Method for Determining Condensable Particulate Emissions From Stationary Sources. Method 5 may be substituted for Method 201A if all particulate matter is assumed to be PM2.5. The purpose of the test is to demonstrate compliance with the emission limits of this permit; therefore, conduct each test run within 80 percent of maximum permitted load, or within 10 percent of 100 percent maximum achievable load. Use alternate stack test methods only with the prior approval of the Office of Environmental Services. Provide necessary sampling ports in stacks or ducts and such other safe and proper sampling and testing facilities for proper determination of the emission limits, as required by LAC 33:III.913.
127 [LAC 33:III.509]	Good combustion practices shall be demonstrated by continuously monitoring the air-to-fuel ratio and maintaining the ratio within the range recommended by the manufacturer.
128 [LAC 33:III.509]	Nitrogen oxides (NOx) <= 2.0 ppm @ 15%O2. NOx BACT: the use of dry low-NOx combustor design, selective catalytic reduction (SCR), and good combustion practices. Install and utilize a CEMS as prescribed by NSPS Subpart KKKK and conduct an initial performance test as required by NSPS Subpart KKKK. Which Months: Phases: Statistical Basis: 24-hour rolling average based on a one-hour average

EQT 0002 CCGT-2 - Combined Cycle Gas Turbine w/ Duct Burners and HSRG

129 [LAC 33:III.509]	Particulate matter (10 microns or less) (PM10) <= 0.008 lb/MMBTU. PM10 BACT: Use of gaseous fuel (pipeline-quality natural gas or a blend of up to 50% H2 and natural gas) and good combustion practices. Which Months: Phases: Statistical Basis: Three one-hour test average
130 [LAC 33:III.509]	Particulate matter (2.5 microns or less) (PM2.5) <= 0.008 lb/MMBTU. PM2.5 BACT: Use of gaseous fuel (pipeline-quality natural gas or a blend of up to 50% H2 and natural gas) and good combustion practices. Which Months: Phases: Statistical Basis: Three one-hour test average
131 [LAC 33:III.509]	Sulfuric Acid BACT: Fire only gaseous fuel (pipeline-quality natural gas or a blend of up to 50% H2 and natural gas).
132 [LAC 33:III.509]	With duct firing: VOC, Total <= 2.0 ppmdv @ 15% O2. VOC BACT: Use of catalytic oxidation and good combustion practices. Which Months: Phases: Statistical Basis: Three one-hour test average
133 [LAC 33:III.509]	Without duct firing: VOC, Total <= 1.0 ppmdv @ 15% O2. VOC BACT: Use of catalytic oxidation and good combustion practices. Which Months: Phases: Statistical Basis: Three one-hour test average

EQT 0003 EGEN-2 - Emergency Diesel Generator

134 [40 CFR 60.4205(b)]	Comply with the emission standards for new nonroad CI engines in 40 CFR 60.4202, for all pollutants, for the same model year and maximum engine power. Subpart IIII. [40 CFR 60.4205(b)]
135 [40 CFR 60.4206]	Operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4204 and 40 CFR 60.4205 over the entire life of the engine. Subpart IIII.
136 [40 CFR 60.4207(b)]	Use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted. Subpart IIII. [40 CFR 60.4207(b)]
137 [40 CFR 60.4209(a)]	Operating time monitored by hour/time monitor continuously during operation. If the emergency engine meets the standards applicable to emergency engines, install a non-resettable hour meter prior to startup of the engine. Subpart IIII. [40 CFR 60.4209(a)] Which Months: All Year Statistical Basis: None specified
138 [40 CFR 60.4211(a)(1)]	Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions, except as permitted in 40 CFR 60.4211(g). Subpart IIII. [40 CFR 60.4211(a)(1)]
139 [40 CFR 60.4211(a)(2)]	Change only those emission-related settings that are permitted by the manufacturer, except as permitted in 40 CFR 60.4211(g). Subpart IIII. [40 CFR 60.4211(a)(2)]
140 [40 CFR 60.4211(a)(3)]	Meet the requirements of 40 CFR 1068, as applicable, except as permitted in 40 CFR 60.4211(g). Subpart IIII. [40 CFR 60.4211(a)(3)]
141 [40 CFR 60.4211(c)]	Ensure engine is certified to the emission standards in 40 CFR 60.4204(b), or 40 CFR 60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. Install and configure according to the manufacturer's emissions-related specifications, except as permitted in 40 CFR 60.4211(g). Subpart IIII. [40 CFR 60.4211(c)]
142 [40 CFR 60.4211(e)(2)]	Conduct a performance test to demonstrate initial compliance with emission standards according to the requirements specified in 40 CFR 60.4212 or 40 CFR 60.4213, as appropriate, within 60 days after commencing operation after a modification or reconstruction. Subpart IIII. [40 CFR 60.4211(e)(2)]
143 [40 CFR 60.4211(f)(1)]	There is no time limit on the use of emergency stationary ICE in emergency situations. Subpart IIII. [40 CFR 60.4211(f)(1)]

EQT 0003 EGEN-2 - Emergency Diesel Generator

144 [40 CFR 60.4211(f)(2)(i)]	Operate for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, provided that the tests are recommended by the federal, state or local government; the manufacturer; the vendor; the regional transmission organization or equivalent balancing authority and transmission operator; or the insurance company associated with the engine. LDEQ may be petitioned for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if records are maintained indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. Subpart IIII. [40 CFR 60.4211(f)(2)(i)]
145 [40 CFR 60.4211(f)(3)]	Operate for up to 50 hours per calendar year in non-emergency situations. Count the 50 hours of operation in non-emergency situations as part of the 100 hours per calendar year for maintenance and testing provided in 40 CFR 60.4211(f)(2)(i). Do not use the 50 hours per calendar year for non-emergency situations for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity, except as provided in 40 CFR 60.4211(f)(3)(i). Subpart IIII. [40 CFR 60.4211(f)(3)]
146 [40 CFR 60.4211(f)]	Operate according to the requirements in 40 CFR 60.4211(f)(1), (f)(2)(i), and (f)(3). In order for the engine to be considered an emergency stationary ICE under 40 CFR 60 Subpart IIII, any operation other than as described in 40 CFR 60.4211(f)(1), (f)(2)(i), and (f)(3) is prohibited. If the engine is not operated according to these requirements, the engine will not be considered an emergency engine under 40 CFR 60 Subpart IIII and must meet all requirements for non-emergency engines. Subpart IIII. [40 CFR 60.4211(f)]
147 [40 CFR 60.4211(g)(1)]	Conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year if the engine and control device are not installed, configured, operated, and maintained to the manufacturer's emission-related written instructions or the emission-related settings are changed in a way that is not permitted by the manufacturer. Subpart IIII. [40 CFR 60.4211(g)(1)]
148 [40 CFR 60.4211(g)(3)]	Keep a maintenance plan and records of conducted maintenance. Subpart IIII. [40 CFR 60.4211(g)(3)]
149 [40 CFR 60.4211(g)(3)]	Maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. Subpart IIII. [40 CFR 60.4211(g)(3)]
150 [40 CFR 60.4211(g)]	Conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year after the engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions (can include within 1 year of startup) or within 1 year after the emission-related settings are changed in a way that is not permitted by the manufacturer. Conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance, if the engine is greater than 500 HP. Subpart IIII. [40 CFR 60.4211(g)]
151 [40 CFR 60.4214(b)]	Operating time recordkeeping by electronic or hard copy upon occurrence of event. If the emergency engine meets the standards applicable to emergency engines in the applicable model year, keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. Record the time of operation of the engine and the reason the engine was in operation during that time. Subpart IIII. [40 CFR 60.4214(b)]
152 [40 CFR 60.4214(f)]	Submit performance test results electronically to EPA following the procedures specified 40 CFR 60.4245(f)(1) and (f)(2) within 60 days after the date of completing each performance test required by 40 CFR 60 Subpart IIII, beginning on February 26, 2025. Subpart IIII. [40 CFR 60.4214(f)]
153 [40 CFR 60.4214(g)]	Submit notifications or reports to EPA via the Compliance and Emissions Data Reporting Interface (CEDRI) as specified in 40 CFR 60.4214(g), if required to submit notifications or reports following the procedures specified in 40 CFR 60.4214(g). Subpart IIII. [40 CFR 60.4214(g)]
154 [40 CFR 63.6590(b)(1)(ii)]	Meet the initial notification requirements of 40 CFR 63.6645(f). Subpart ZZZZ. [40 CFR 63.6590(b)(1)(ii)]

EQT 0003 EGEN-2 - Emergency Diesel Generator

155 [LAC 33:III.1101.B]	Opacity <= 20 percent, except for emissions that have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes. Determine opacity by using Method 9 of 40 CFR Part 60, Appendix A or by using a continuous opacity monitoring system (COMS) meeting the requirements outlined in 40 CFR 60.13(c) and (d). Which Months: All Year Statistical Basis: None specified
156 [LAC 33:III.1311.C]	Opacity <= 20 percent, except for emissions that have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes. Which Months: All Year Statistical Basis: Six-minute average
157 [LAC 33:III.507.H.1.a]	Permittee shall ensure compliance with the opacity limits of this permit by visually inspecting the emergency engine's stack for visible emissions once each month or at each readiness testing event if the engine is tested at a frequency less than monthly. If visible emissions are not detected during the initial six minutes of the inspection, the inspection may be concluded. If visible emissions are detected, the inspection period shall be extended to one hour (60 consecutive minutes) or the duration of the test, whichever is shorter. If visible emissions are detected for more than one 6-minute period over the test period, the permittee shall conduct a 6-minute opacity reading in accordance with Method 9 of 40 CFR 60, Appendix A, during the next required visible emissions check. If the shade or appearance of the emission is darker than 20 percent average opacity (per Method 9), the permittee shall 1.) take corrective action to return the engine to its proper operating condition, and 2.) repeat the 6-minute opacity reading in accordance with Method 9. Records of visible emissions checks shall include the engine's ID number, the date the visual check was performed, a record if visible emissions were detected during the initial six minutes of the inspection, a record if visible emissions were detected for more than one 6-minute period over the test period (if required), a record and the results of any Method 9 testing conducted, and a record of any corrective action employed. These records shall be kept on-site and available for inspection by the Office of Environmental Compliance. As an alternative to the requirement to conduct Method 9 testing, the permittee may assume that any visible emissions detected constitute opacity greater than 20 percent. In this case, no visible emissions detected shall be considered opacity less than or equal to 20 percent, even if a qualitative assessment suggests otherwise. The permittee may also determine opacity via any federally-approved alternative to Method 9 (e.g., Method ALT-082). In lieu of performing an initial visual inspection each month, the permittee may immediately perform a six-minute opacity reading in accordance with Method 9.
158 [LAC 33:III.509]	BACT for PM10, PM2.5, NOx, CO, VOC, and CO2e is defined as compliance with 40 CFR Part 60 Subpart IIII (Tier 2 non-road engines), good combustion practices, and the use of ultra low sulfur diesel. Good combustion practices entail operating and maintaining the engine in accordance with the manufacturer's instructions and/or recommendations. Camellia Power shall keep a maintenance plan and records of maintenance conducted on the engine.

EQT 0004 FWP-2 - Emergency Diesel Fire Water Pump

159 [40 CFR 60.4205(c)]	Non-methane hydrocarbons plus Nitrogen oxides (NOx) <= 3.0 g/BHP-hr (4.0 g/KW-hr). Subpart IIII. [40 CFR 60.4205(c)] Which Months: All Year Statistical Basis: None specified
160 [40 CFR 60.4205(c)]	Particulate matter (10 microns or less) (PM10) <= 0.15 g/BHP-hr (0.20 g/KW-hr). Subpart IIII. [40 CFR 60.4205(c)] Which Months: All Year Statistical Basis: None specified
161 [40 CFR 60.4206]	Operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4204 and 40 CFR 60.4205 over the entire life of the engine. Subpart IIII.
162 [40 CFR 60.4207(b)]	Use diesel fuel that meets the requirements of 40 CFR 1090.305 for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted. Subpart IIII. [40 CFR 60.4207(b)]

EQT 0004 FWP-2 - Emergency Diesel Fire Water Pump

163 [40 CFR 60.4209(a)]	Operating time monitored by hour/time monitor continuously during operation. If the emergency engine meets the standards applicable to emergency engines, install a non-resettable hour meter prior to startup of the engine. Subpart IIII. [40 CFR 60.4209(a)] Which Months: All Year Statistical Basis: None specified
164 [40 CFR 60.4211(a)(1)]	Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions, except as permitted in 40 CFR 60.4211(g). Subpart IIII. [40 CFR 60.4211(a)(1)]
165 [40 CFR 60.4211(a)(2)]	Change only those emission-related settings that are permitted by the manufacturer, except as permitted in 40 CFR 60.4211(g). Subpart IIII. [40 CFR 60.4211(a)(2)]
166 [40 CFR 60.4211(a)(3)]	Meet the requirements of 40 CFR 1068, as applicable, except as permitted in 40 CFR 60.4211(g). Subpart IIII. [40 CFR 60.4211(a)(3)]
167 [40 CFR 60.4211(c)]	Ensure engine is certified to the emission standards in 40 CFR 60.4204(b), or 40 CFR 60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. Install and configure according to the manufacturer's emissions-related specifications, except as permitted in 40 CFR 60.4211(g). Subpart IIII. [40 CFR 60.4211(c)]
168 [40 CFR 60.4211(f)(1)]	There is no time limit on the use of emergency stationary ICE in emergency situations. Subpart IIII. [40 CFR 60.4211(f)(1)]
169 [40 CFR 60.4211(f)(2)(i)]	Operate for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, provided that the tests are recommended by the federal, state or local government; the manufacturer; the vendor; the regional transmission organization or equivalent balancing authority and transmission operator; or the insurance company associated with the engine. LDEQ may be petitioned for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if records are maintained indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year. Subpart IIII. [40 CFR 60.4211(f)(2)(i)]
170 [40 CFR 60.4211(f)(3)]	Operate for up to 50 hours per calendar year in non-emergency situations. Count the 50 hours of operation in non-emergency situations as part of the 100 hours per calendar year for maintenance and testing provided in 40 CFR 60.4211(f)(2)(i). Do not use the 50 hours per calendar year for non-emergency situations for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity, except as provided in 40 CFR 60.4211(f)(3)(i). Subpart IIII. [40 CFR 60.4211(f)(3)]
171 [40 CFR 60.4211(f)]	Operate according to the requirements in 40 CFR 60.4211(f)(1), (f)(2)(i), and (f)(3). In order for the engine to be considered an emergency stationary ICE under 40 CFR 60 Subpart IIII, any operation other than as described in 40 CFR 60.4211(f)(1), (f)(2)(i), and (f)(3) is prohibited. If the engine is not operated according to these requirements, the engine will not be considered an emergency engine under 40 CFR 60 Subpart IIII and must meet all requirements for non-emergency engines. Subpart IIII. [40 CFR 60.4211(f)]
172 [40 CFR 60.4211(g)(2)]	Conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year if the engine and control device are not installed, configured, operated, and maintained to the manufacturer's emission-related written instructions or the emission-related settings are changed in a way that is not permitted by the manufacturer. Subpart IIII. [40 CFR 60.4211(g)(2)]
173 [40 CFR 60.4211(g)(2)]	Keep a maintenance plan and records of conducted maintenance. Subpart IIII. [40 CFR 60.4211(g)(2)]
174 [40 CFR 60.4211(g)]	Maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions if the engine and control device are not installed, configured, operated, and maintained to the manufacturer's emission-related written instructions or the emission-related settings are changed in a way that is not permitted by the manufacturer. Subpart IIII. [40 CFR 60.4211(g)]
175 [40 CFR 60.4214(b)]	Operating time recordkeeping by electronic or hard copy upon occurrence of event. If the emergency engine meets the standards applicable to emergency engines in the applicable model year, keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. Record the time of operation of the engine and the reason the engine was in operation during that time. Subpart IIII. [40 CFR 60.4214(b)]
176 [40 CFR 63.6590(c)]	Meet the requirements of 40 CFR 60 Subpart IIII for compression ignition engines. [40 CFR 63.6590(c)]

EQT 0004 FWP-2 - Emergency Diesel Fire Water Pump

177 [LAC 33:III.1101.B]	Opacity <= 20 percent, except for emissions that have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes. Determine opacity by using Method 9 of 40 CFR Part 60, Appendix A or by using a continuous opacity monitoring system (COMS) meeting the requirements outlined in 40 CFR 60.13(c) and (d). Which Months: All Year Statistical Basis: None specified
178 [LAC 33:III.1311.C]	Opacity <= 20 percent, except for emissions that have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes. Which Months: All Year Statistical Basis: Six-minute average
179 [LAC 33:III.507.H.1.a]	Permittee shall ensure compliance with the opacity limits of this permit by visually inspecting the emergency engine's stack for visible emissions once each month or at each readiness testing event if the engine is tested at a frequency less than monthly. If visible emissions are not detected during the initial six minutes of the inspection, the inspection may be concluded. If visible emissions are detected, the inspection period shall be extended to one hour (60 consecutive minutes) or the duration of the test, whichever is shorter. If visible emissions are detected for more than one 6-minute period over the test period, the permittee shall conduct a 6-minute opacity reading in accordance with Method 9 of 40 CFR 60, Appendix A, during the next required visible emissions check. If the shade or appearance of the emission is darker than 20 percent average opacity (per Method 9), the permittee shall 1.) take corrective action to return the engine to its proper operating condition, and 2.) repeat the 6-minute opacity reading in accordance with Method 9. Records of visible emissions checks shall include the engine's ID number, the date the visual check was performed, a record if visible emissions were detected during the initial six minutes of the inspection, a record if visible emissions were detected for more than one 6-minute period over the test period (if required), a record and the results of any Method 9 testing conducted, and a record of any corrective action employed. These records shall be kept on-site and available for inspection by the Office of Environmental Compliance. As an alternative to the requirement to conduct Method 9 testing, the permittee may assume that any visible emissions detected constitute opacity greater than 20 percent. In this case, no visible emissions detected shall be considered opacity less than or equal to 20 percent, even if a qualitative assessment suggests otherwise. The permittee may also determine opacity via any federally-approved alternative to Method 9 (e.g., Method ALT-082). In lieu of performing an initial visual inspection each month, the permittee may immediately perform a six-minute opacity reading in accordance with Method 9.
180 [LAC 33:III.509]	BACT for PM10, PM2.5, NOx, CO, VOC, and CO2e is defined as compliance with 40 CFR Part 60 Subpart IIII (Tier 2 non-road engines), good combustion practices, and the use of ultra low sulfur diesel. Good combustion practices entail operating and maintaining the engine in accordance with the manufacturer's instructions and/or recommendations. Camellia Power shall keep a maintenance plan and records of maintenance conducted on the engine.

EQT 0005 TK-6 - Atmospheric Drains Tank

181 [LAC 33:III.509]	Tank shall be equipped with a submerged fill pipe.

EQT 0006 CB-2 - Circuit Breakers

182 [LAC 33:III.509]	BACT for CO2e for the Circuit Breakers shall be an enclosed pressure design with a low pressure detection system and an alarm to limit the SF6 leak rate to 0.5 % per year. The Circuit Breakers shall be designed to meet the current American National Standards Institute (ANSI) standards for high voltage circuit breakers. Compliance with emission limits shall be demonstrated using the methodology in 40 CFR 98 Subpart DD.

FUG 0001 FUG-2 - Unit 2 Fugitive Emissions

183 [LAC 33:III.509]	Proper piping design and installation shall be CO2e BACT.

SCN 0002 CCGT-SUSD-2 - Combined Cycle Gas Turbine 2 - Startup and Shutdown

Group Members: EQT 2

184 [LAC 33:III.501.C.6]	No later than 90 days after the shakedown period ends, the permittee shall submit an application requesting that such parameter(s) and value(s) be incorporated into the permit.
185 [LAC 33:III.501.C.6]	The permittee shall identify the appropriate parameter(s) and value(s) during the shakedown period of the CCGT Unit that define when a startup ends and when a shutdown begins.
186 [LAC 33:III.507.H.1.a]	Permittee shall maintain records of the duration of each startup and shutdown of CCGT-1, including dates and start/end times. These records shall be maintained onsite and made available for inspection for the Office of Environmental Compliance, Surveillance Division.
187 [LAC 33:III.509]	BACT for PM10, PM2.5, H2SO4, NOx, CO2e, CO, and VOC is defined as good combustion practices. Good combustion practices entail following the startup and shutdown procedures recommended by the turbine manufacturer. Camellia Power shall 1.) develop a written startup and shutdown plan that describes, in detail, procedures for operating and maintaining the source during periods of startup and shutdown; and 2.) keep records of any actions taken during a startup or shutdown that are not consistent with the procedures specified in the plan and which resulted in an exceedance of emission limitations.

UNF 0001 FW Unit 2 - Facility Wide Unit 2

188 [40 CFR 60.]	All affected facilities shall comply with all applicable provisions in 40 CFR 60 Subpart A.
189 [40 CFR 63.]	All affected facilities shall comply with all applicable provisions in 40 CFR 63 Subpart A.
190 [LAC 33:III.1103]	Emissions of smoke which pass onto or across a public road and create a traffic hazard by impairment of visibility as defined in LAC 33:III.111 or intensifies an existing traffic hazard condition are prohibited.
191 [LAC 33:III.1109.B]	Outdoor burning of waste material or other combustible material is prohibited.
192 [LAC 33:III.1303.B]	Emissions of particulate matter which pass onto or across a public road and create a traffic hazard by impairment of visibility or intensify an existing traffic hazard condition are prohibited.
193 [LAC 33:III.2113.A]	Maintain best practical housekeeping and maintenance practices at the highest possible standards to reduce the quantity of organic compounds emissions. Good housekeeping includes, but is not limited to, the practices listed in LAC 33:III.2113.A.1 through A.5.
194 [LAC 33:III.219]	Failure to pay the prescribed application fee or annual fee as provided herein, within 90 days after the due date, will constitute a violation of these regulations and shall subject the person to applicable enforcement actions under the Louisiana Environmental Quality Act including, but not limited to, revocation or suspension of the applicable permit, license, registration, or variance.
195 [LAC 33:III.501]	CO2e <= 2,699,483 tons/yr.
196 [LAC 33:III.505]	Operate the unit in compliance with a complete Acid Rain permit application or superseding Acid Rain permit issued by the permitting authority, and have an Acid Rain Permit.
197 [LAC 33:III.509]	Comply with the requirements of PSD-LA-863. This permit includes provisions of the Prevention of Significant Deterioration (PSD) review from Permit PSD-LA-863.
198 [LAC 33:III.5105.A.2]	Do not cause a violation of any ambient air standard listed in LAC 33:III.5112, Table 51.2, unless operating in accordance with LAC 33:III.5109.B.
199 [LAC 33:III.5107.A.2]	Include a certification statement with the annual emission report and revisions to any emission report that attests that the information contained in the emission report is true, accurate, and complete, and that is signed by a responsible official, as defined in LAC 33:III.502. Include the full name of the responsible official, title, signature, date of signature, and phone number of the responsible official.

UNF 0001 FW Unit 2 - Facility Wide Unit 2

200 [LAC 33:III.5107.A]	Submit Annual Emissions Report: Due annually by the 30th of April, unless otherwise directed by DEQ, to the Office of Environmental Services in a format specified by DEQ. Identify the quantity of emissions in the previous calendar year for any toxic air pollutant listed in LAC 33:III.5112, Table 51.1 or Table 51.3.
201 [LAC 33:III.5107.B.1]	Submit notification: Due to the Department of Public Safety 24-hour Louisiana Emergency Hazardous Materials Hotline in accordance with LAC 33:I.3915.A, after any discharge of a toxic air pollutant into the atmosphere that results or threatens to result in an emergency condition, as defined in LAC 33:I.3905.A.
202 [LAC 33:III.5107.B.2]	Submit notification: Due to SPOC, except as provided in LAC 33:III.5107.B.4, immediately, but in no case later than 24 hours after any unauthorized discharge of a toxic air pollutant into the atmosphere that does not cause an emergency condition, the rate or quantity of which is in excess of that allowed by permit, compliance schedule, or variance, or for upset events that exceed the reportable quantity in LAC 33:I.3931. Submit notification in the manner provided in LAC 33:I.3923.
203 [LAC 33:III.5107.B.3]	Submit written report: Due by certified mail to SPOC within seven calendar days of learning of any such discharge or equipment bypass as referred to in LAC 33:III.5107.B.1 and B.2. Include the information specified in LAC 33:III.5107.B.3.a.i through B.3.a.viii.
204 [LAC 33:III.5109.C.2]	Develop a standard operating procedure (SOP) within 120 days after achieving or demonstrating compliance with the standards specified in LAC 33:III.Chapter 51. Detail in the SOP all operating procedures or parameters established to ensure that compliance with the applicable standards is maintained and address operating procedures for any monitoring system in place, specifying procedures to ensure compliance with LAC 33:III.5113.C.5. Make a written copy of the SOP available on site or at an alternate approved location for inspection by DEQ. Provide a copy of the SOP within 30 days upon request by DEQ.
205 [LAC 33:III.535]	Comply with the Part 70 General Conditions as set forth in LAC 33:III.535 and the Louisiana General Conditions as set forth in LAC 33:III.537. [LAC 33:III.535, LAC 33:III.537]
206 [LAC 33:III.5609.A.1.b]	Activate the preplanned abatement strategy listed in LAC 33:III.5611.Table 5 when DEQ declares an Air Pollution Alert.
207 [LAC 33:III.5609.A.2.b]	Activate the preplanned strategy listed in LAC 33:III.5611.Table 6 when DEQ declares an Air Pollution Warning.
208 [LAC 33:III.5609.A.3.b]	Activate the preplanned abatement strategy listed in LAC 33:III.5611.Table 7 when DEQ declares an Air Pollution Emergency.
209 [LAC 33:III.5609.A]	Prepare standby plans for the reduction of emissions during periods of Air Pollution Alert, Air Pollution Warning and Air Pollution Emergency. Design standby plans to reduce or eliminate emissions in accordance with the objectives as set forth in LAC 33:III.5611. Tables 5, 6, and 7.
210 [LAC 33:III.905]	Install air pollution control facilities whenever practically, economically, and technologically feasible, except as specified in LAC 33:III.905.B. When facilities have been installed on a property, use and diligently maintain in proper working order whenever any emissions are being made which can be controlled by the facilities, even though the ambient air quality standards in affected areas are not exceeded.
211 [LAC 33:III.919]	Submit Emission Inventory (EI)/Annual Emissions Statement: Due annually by the 30th of April to the Office of Environmental Assessment for the reporting period of the previous calendar year that coincides with period of ownership or operatorship, until released from reporting, in writing, by DEQ. Submit both an emissions inventory and the certification statement required by LAC 33:III.919.F.1.c, separately for each AI, in a format specified by DEQ. To request a release from reporting, submit a completed Request for Release from Emissions Inventory Reporting form (form# 7365) to the Office of Environmental Services.
212 [LAC 33:III.927]	Report the unauthorized discharge of any air pollutant into the atmosphere in accordance with LAC 33:I.Chapter 39, Notification Regulations and Procedures for Unauthorized Discharges. Submit written reports to DEQ pursuant to LAC 33:I.3925. Submit timely and appropriate follow-up reports detailing methods and procedures to be used to prevent similar atmospheric releases.

JEFF LANDRY
GOVERNOR

COURTNEY J. BURDETTE
SECRETARY

STATE OF LOUISIANA

DEPARTMENT OF ENVIRONMENTAL QUALITY
OFFICE OF ENVIRONMENTAL SERVICES

Certified Mail No.

Agency Interest (AI) No. 246887
Activity No. PER20240002

Ms. Lisa Carty
Vice President, Environmental
Camellia Power LLC
500 Alexander Park Drive, Suite 300
Princeton, NJ 08540

RE: Prevention of Significant Deterioration (PSD) Permit, PSD-LA-863
Camellia Power Unit 2, Camellia Power LLC
Plaquemine, Iberville Parish, Louisiana

Dear Ms. Carty:

Enclosed is your permit, PSD-LA-863. Construction of the proposed project is not allowed until such time as the corresponding Part 70 Operating Permit is issued.

Please be advised that pursuant to provisions of the Environmental Quality Act and the Administrative Procedure Act, the Department may initiate review of a permit during its term. However, before it takes any action to modify, suspend or revoke a permit, the Department shall, in accordance with applicable statutes and regulations, notify the permittee by mail of the facts or operational conduct that warrant the intended action and provide the permittee with the opportunity to demonstrate compliance with all lawful requirements for the retention of the effective permit.

Should you have any questions, contact Mr. Anthony Randall of the Air Permits Division at (225) 219-3494 or anthony.randall@la.gov.

Sincerely,

Amanda Vincent, PhD, PMP
Assistant Secretary

_____
Date

AV:alr

c: US EPA Region VI

Agency Interest No. 246887

PSD-LA-863

AUTHORIZATION TO CONSTRUCT AND OPERATE A NEW FACILITY PURSUANT TO THE PREVENTION OF SIGNIFICANT DETERIORATION REGULATIONS IN LOUISIANA ENVIRONMENTAL REGULATORY CODE, LAC 33:III.509

In accordance with the provisions of the Louisiana Environmental Regulatory Code, LAC 33:III.509,

Camellia Power LLC
500 Alexander Park Drive, Suite 300
Princeton, NJ 08450

is authorized to construct the Camellia Power Unit 2 located at

26620 River Road
Plaquemine Louisiana 70764

subject to the emissions limitations, monitoring requirements, and other conditions set forth hereinafter.

This permit and authorization to construct shall expire at midnight on _____, 2027, unless physical on site construction has begun by such date, or binding agreements or contractual obligations to undertake a program of construction of the source are entered into by such date.

Signed this _____ day of _____, 2025.

Amanda Vincent, PhD, PMP
Assistant Secretary
Office of Environmental Services
Louisiana Department of Environmental Quality

BRIEFING SHEET

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine, Iberville Parish, Louisiana
PSD-LA-863

I. APPLICANT

The applicant is: Camellia Power LLC
500 Alexander Park Drive, Suite 300
Princeton, NJ 08450

~~Facility: Camellia Power Unit 2~~

SIC Code: 4911

II. LOCATION

The facility will be located at 26620 River Road, Plaquemine, Louisiana 70764.

III. REVIEWING AGENCY

Louisiana Department of Environmental Quality (LDEQ)
Office of Environmental Services / Air Permits Division
P.O. Box 4313
Baton Rouge, Louisiana 70821-4313

IV. PURPOSE

To obtain a PSD permit for authorization to construct and operate the Camellia Power Unit 2.

V. PROJECT DESCRIPTION

Camellia Power requested authorization to construct a power plant, Camellia Power Unit 2, consisting of a natural gas-fired combined cycle gas turbine (CCGT Unit) and other ancillary equipment in Iberville Parish, Louisiana. The CCGT Unit [Emission Point Number (EPN) CCGT-2, EQT0002] will include a heat recovery steam generator (HRSG) and have a net nominal output of approximately 730 megawatts.

Ancillary equipment associated with Unit 2 will include:

- One (1) 2,937 horsepower Emergency Diesel Generator (EPN EGEN-2, EQT0003);
- One (1) 355 horsepower Emergency Diesel Fire Water Pump (EPN FWP-2, EQT0004);
- One (1) 80 MMBtu/hr Auxiliary Boiler (EPN BOIL-2, EQT0001) to provide auxiliary steam for the CCGT-2 during startup;
- One (1) 5,475 gallon Atmospheric Drains Tank (EPN TK-6, EQT0005);
- Four (4) Circuit Breakers (EPN CB-2, EQT0006) insulated with sulfur hexaflouride (SF_6); and
- Unit 2 fugitive sources (EPN FUG-2, FUG0001).

CCGT-2 will use either natural gas or a blend of up to 50% hydrogen and natural gas. Camellia Power will not use the blended gas during startup or shutdown operations. The HRSG will be equipped with duct burners, which provide supplemental natural gas firing, allowing the facility to vary the unit's electrical output to meet customer demand.

The excess heat absorbed by the HRSG will convert incoming feed water to steam, which will rotate the steam turbine generator. Combined-cycle units are more efficient than gas turbines or steam turbine generators alone because additional electricity is generated from the steam created from the combustion turbine's waste heat.

The combustion of natural gas in the combustion turbine has the potential to generate NO_X emissions, which will be controlled using dry low-NO_X combustors, selective catalytic reduction (SCR), and good combustion practices. An oxidation catalyst will control VOC and CO emissions. The use of pipeline quality natural gas, along with good combustion practices, will minimize PM_{10}, $PM_{2.5}$, sulfuric acid mist, and CO_2e emissions.

The CCGT Unit selected by Camellia Power for Unit 2 will be "up to 50% hydrogen capable with a technology pathway to 100%," which means that once hydrogen becomes commercially available, the unit will be capable of producing electricity without generating carbon pollution.

VI. APPLICABILITY AND REGULATED POLLUTANTS

Camellia Power LLC's proposed Camellia Power Unit 2 will be located in Iberville Parish, which is an area currently designated by EPA as attainment or unclassifiable for all pollutants having National Ambient Air Quality Standards (NAAQS) (40 CFR 81.319). Therefore, federal Non-Attainment New Source Review (NNSR) regulations are not applicable to the project.

A "major stationary source" under the PSD regulations is defined as any source that emits or has the potential to emit 250 tons per year (TPY) or more of at least one criteria pollutant or 100 TPY or more if the source belongs to one of the 28 specifically listed industrial source categories in the definition of "major stationary source." The major source threshold for Camellia Power Unit 2 is 100 TPY.

Potential emissions of PM_{10}, $PM_{2.5}$, NO_X, CO, and VOC will exceed the major source threshold of 100 tpy. Additionally, emissions of greenhouse gases will be greater than its significant emission rate.

Permitted emissions for Camellia Power Unit 2 (for the pollutants triggering PSD review) are set forth in the table below. Amounts are listed in tons per year (TPY).

BRIEFING SHEET

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine, Iberville Parish, Louisiana
PSD-LA-863

Pollutant	Emissions	PSD Significant Emissions Rate	PSD Review Required?
PM_{10}	131.21	15	Yes
$PM_{2.5}$	131.21	10	Yes
SO_2	38.12	40	No
NO_X	176.50	40	Yes
CO	243.39	100	Yes
VOC	101.19	40	Yes
Sulfuric acid mist (H_2SO_4)	25.40	10	Yes
CO_2e	2,699,483	75,000	Yes

VII. PRELIMINARY DETERMINATION

LAC 33:III.509.Q.2.a requires LDEQ to "make a preliminary determination whether construction should be approved, approved with conditions, or disapproved." Based on the findings set forth in the Preliminary Determination Summary, the Office of Environmental Services has made a preliminary determination to approve construction of Camellia Power Unit 2 in Plaquemine, Iberville Parish, subject to the maximum allowable emissions rates and specific conditions established herein.

VIII. PROCESSING TIME

Application Dated:	December 17, 2024
Application Received:	December 23, 2024
Addition Information Received:	July 2, 2025
Effective Completeness Date:	March 12, 2025

IX. PUBLIC NOTICE

In accordance with LAC 33:III.509.Q.2.c, a notice requesting public comment and announcing a public hearing on the proposed permit was published on the department's website on <<Date>>. On <<Date>>, copies of the public notice were mailed to the individuals who have requested to be placed on the mailing list maintained by the Office of Environmental Services (OES). The proposed permit was submitted to EPA on <<Date>>. All comments will be considered prior to a final permit decision.

PRELIMINARY DETERMINATION SUMMARY

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine Iberville Parish, Louisiana
PSD-LA-863
March 12, 2025

PSD REQUIREMENTS

This Preliminary Determination Summary summarizes the results of the reviews and analyses required by LAC 33:III.509. PSD requirements are outlined below.

A. Control Technology Review[1]

1. Best Available Control Technology (BACT)
2. Collateral Environmental Impacts

B. Air Quality Analysis[2]

1. Preconstruction Monitoring
2. Background Concentrations

C. Source Impact Analysis[3]

1. Preliminary Screening
2. National Ambient Air Quality Standards
3. PSD Increments[4]
4. Secondary $PM_{2.5}$ Formation

D. Additional Impact Analyses[5]

Visibility
Soils and Vegetation
Commercial, Residential, Industrial, and Other Growth

E. Additional Requirements for Sources Impacting Class I Areas[6]

In the event of a discrepancy in the provisions found in the application and those in this Preliminary Determination Summary, the Preliminary Determination Summary shall prevail.

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[1] LAC 33:III.509.J
[2] LAC 33:III.509.M
[3] LAC 33:III.509.K
[4] LAC 33:III.509.C
[5] LAC 33:III.509.O
[6] LAC 33:III.509.P

PRELIMINARY DETERMINATION SUMMARY

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine Iberville Parish, Louisiana
PSD-LA-863
March 12, 2025

A. CONTROL TECHNOLOGY REVIEW

A.1 Best Available Control Technology

Per LAC 33:III.509.J.2, a new major stationary source shall apply best available control technology (BACT) for each regulated NSR pollutant that it would have the potential to emit in significant amounts.

Consistent with EPA guidance, LDEQ utilizes the "top-down" approach to determine BACT.[7] This approach involves determining the most stringent control technique available for a similar or identical source. If it can be shown that this level of control is infeasible based on technical considerations or adverse energy, environmental, or economic impacts, it is rejected, and the next most stringent level of control is determined and similarly evaluated. This process continues until a control level is arrived at which cannot be eliminated due to technical difficulties or environmental, energy, or economic impacts. However, BACT may not result in emissions of any pollutant that would exceed an applicable standard under 40 CFR Part 60, 61, or 63. The five steps in the top-down process are described below.[8]

Step 1

The first step in a "top-down" analysis is to identify all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation.

Step 2

In the second step, the technical feasibility of each control option identified in step 1 is evaluated with respect to source-specific (or emissions unit-specific) factors. Technically infeasible control options are then eliminated from further consideration.

Step 3

In step 3, all control alternatives not eliminated in step 2 are ranked in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the

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[7] Note that it remains EPA's *policy* to use the top-down process to determine BACT. According to EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases":

> EPA has not established the top-down BACT process as a binding requirement through rule. Thus, permitting authorities that implement an EPA-approved PSD permitting program contained in their State Implementation Plans (SIPs) may use another process for determining BACT in permits they issue ... so long as that process (and each BACT determination made through that process) complies with the relevant statutory and regulatory requirements. (p. 19, internal citations omitted).

[8] Where the top-down process does not provide meaningful information (e.g., if there is only one available control option), LDEQ may not summarize each of the five steps.

top. An applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options.[9]

Step 4

Next, the energy, environmental, and economic impacts of the available and technically feasible control options are considered. Impacts influencing LDEQ's BACT determination are addressed in this Preliminary Determination Summary; those which do not result in the elimination of a control option are detailed in the permit application.

Step 5

The most effective control option not eliminated in step 4 is selected as BACT.

LDEQ's BACT determinations for Camellia Power Unit 2 follow:

BACT Analyses for Combined Cycle Gas Turbine with Duct Burners and HRSG

BACT for $PM_{2.5}/PM_{10}$

EQT0002	**CCGT-2**	**Combined Cycle Gas Turbine 2 with Duct Burners and HRSG**

CCGT-2 will emit PM_{10} and $PM_{2.5}$, which are comprised of filterable and condensable portions. A gaseous fuel combustion device can emit PM_{10} and $PM_{2.5}$ due to the incomplete combustion of higher molecular weight hydrocarbons in the device's gaseous fuel. However, the turbine will combust pipeline-quality natural gas, or a blend of up 50% hydrogen and natural gas, fuels primarily comprised of hydrogen and relatively low molecular weight hydrocarbons. Therefore, elevated PM_{10} and $PM_{2.5}$ emissions from the turbine due to the incomplete combustion of high molecular weight hydrocarbons are not expected to occur. Additionally, when natural gas is used as fuel in a turbine, PM emissions are negligible due to the low ash content of the fuel. Moreover, the referenced fuels will contain low levels of sulfur, further minimizing the generation of condensable PM_{10} and $PM_{2.5}$. The addition of ammonia to control NO_X with the SCR can result in increased PM_{10} and $PM_{2.5}$ emissions as a result of ammonia slip.

Step 1 – Identify All Control Technologies

The following are available PM emission control technologies for CCGT-2.

1. Good Combustion Practices and Use of Gaseous Fuels
2. Electrostatic Precipitator (ESP)
3. Wet Scrubber

[9] "New Source Review Workshop Manual" (draft), October 1990 (p. B.8)

4. Filter
5. Cyclone

Good Combustion Practices and Use of Gaseous Fuels

Good combustion practices for gaseous fuel-fired combustion devices consist of properly setting and controlling the air-to-fuel ratio and ensuring appropriate combustion zone residence time, temperature, and turbulence parameters essential to achieving low emission levels for all products of combustion, including NO_X, CO, VOC, PM_{10} and $PM_{2.5}$. Incomplete combustion of fuel hydrocarbons can occur because of improper combustion mechanisms, resulting from poor burner/combustion device design, operation, and/or maintenance. However, combustion devices (e.g., turbines, heaters, boilers) are designed and typically operated to maximize fuel combustion efficiency so that fuel usage costs are minimized while process heating performance is maximized. Good combustion practices can be achieved by following a combustion device manufacturer's operating procedures and guidelines.

Electrostatic Precipitator (ESP)

An ESP uses an electric field and collection plates to remove PM from a flowing gaseous stream. The PM in the gaseous stream is given an electric charge by passing the stream through a corona discharge. The resulting negatively charged PM is collected on grounded collection plates, which are periodically cleaned without re-entraining the PM into the gaseous stream that the ESP is treating. In a dry ESP, the collection plate cleaning process is accomplished mechanically by knocking the PM loose from the plates. Alternatively, in a wet ESP, a washing technique is used to remove the collected PM from the collection plates. ESPs can be configured in several ways, including a plate-wire ESP, a flat-plate ESP, and a tubular ESP. As the diameter of the PM decreases, the efficiency of an ESP decreases.

Wet Scrubber

A wet scrubber uses absorption to remove PM from a gaseous stream. Absorption is primarily a physical process, though it can also include a chemical component, in which a pollutant in a gas phase contacts a scrubbing liquid and is entrained in the liquid. A key factor dictating the performance of a wet scrubber is the solubility of the pollutant of concern in the scrubbing liquid. Water is commonly used as the scrubbing liquid in a wet scrubber used for PM emission control, but other liquids can be used depending on the type of PM or other pollutant(s) to be removed from the gaseous stream undergoing treatment. There are several types of wet scrubbers, including packed-bed counter flow scrubbers, packed-bed cross-flow scrubbers, bubble plate scrubbers, and tray scrubbers.

Filter

A filter is a porous media that removes PM from a gaseous stream as the stream passes through the filter. For an emissions unit with an appreciable exhaust rate, the filter system typically contains multiple filter elements. Filters can be used to treat exhaust streams containing dry or liquid PM.

Filters handling dry PM become coated with collected PM during operation; this coating ("cake") contributes to the filtration mechanism. A dry PM filter system commonly used in industrial scale applications is a "baghouse." A baghouse is comprised of multiple cylindrical bags, and the number of bags is dependent on the flue gas air flow rate requiring treatment, the PM loading of the exhaust stream, and the baghouse design. The two most common baghouse designs today are the reserve-air and pulse-jet designs. These design references indicate the type of bag cleaning system used in the baghouse.

Filters handling liquid PM rely on the impingement of entrained liquid PM on the surface of the filter media and the retention of these liquid particles on the surface until multiple particles coalesce into particles of sufficient size such that they fall back against the flowing gas stream and collect at a location below the filter. For the high efficiency removal of submicron liquid particles from a gaseous stream, Brownian diffusion filters are used. "Brownian diffusion" is the random movement of submicron particles in a gaseous stream as the particles collide with gas molecules. Liquid PM filter systems can be comprised of pad or candle filter elements. These filter elements require little operation and maintenance attention.

Cyclone
A cyclone is the most common type of inertial separator used to collect medium-sized and coarse PM from gaseous streams. The PM contained in gaseous stream treated in a cyclone moves outward under the influence of centrifugal force until it contacts the wall of the cyclone. The PM is then carried downward by gravity along the wall of the cyclone and collected in a hopper located at the bottom of the cyclone. Although cyclones provide a relatively low cost, mechanically simple option for the removal of larger diameter PM from gaseous streams, alone they do not typically provide adequate PM removal, especially when the gaseous stream contains smaller diameter PM. Instead, these devices are typically used to pre-clean a gaseous stream by removing larger diameter PM upstream of PM emission control devices that are more effective at removing smaller diameter PM.

Step 2 – Eliminate Technically Infeasible Options

ESP
PM emitted by CCGT-2 is estimated to be PM_{10} and $PM_{2.5}$ only, which is a characteristic that would limit the control effectiveness of an ESP. Additionally, the PM_{10} and $PM_{2.5}$ concentrations in the exhaust stream are below those typically seen in an ESP's exhaust stream. Thus, an ESP would not lower emissions by any appreciable amount. Furthermore, research of emission control technology application data sets indicates an ESP has not been used to control PM emissions from a comparable source. These factors indicate that it would not be technically feasible to use an ESP to control PM emissions from the turbine.

Filter
The PM_{10} and $PM_{2.5}$-only profile of CCGT-2 PM emissions would limit the control effectiveness of a filter. Additionally, the PM_{10} and $PM_{2.5}$ concentrations in the exhaust stream are below those typically seen in a filter's exhaust stream. Thus, a filter would not

lower emissions by any appreciable amount. Furthermore, research of emission control technology application data sets indicates a filter has not been used to control PM emissions from a comparable source. These factors indicate it would not be technically feasible to use a filter to control PM emissions from the turbine.

Wet Scrubber

The PM_{10} and $PM_{2.5}$-only profile of the turbine PM emissions indicates a wet scrubber would require a considerable pressure drop to effectively reduce the PM emissions. Additionally, the PM_{10} and $PM_{2.5}$ concentrations in the turbine exhaust stream are below those typically seen in a wet scrubber's exhaust stream. Furthermore, the liquid carryover in the exhaust stream from a wet scrubber contains dissolved and suspended solids, which would result in a new PM emission mechanism, reducing any negligible PM_{10} and $PM_{2.5}$ control effectiveness of the wet scrubber in this application. Moreover, research of emission control technology application data sets indicates a wet scrubber has not been used to control PM emissions from a comparable source. These factors indicate it would not be technically feasible to use a wet scrubber to control PM emissions from the turbine.

Cyclone

The PM_{10} and $PM_{2.5}$-only profile of the turbine PM emissions would limit the control effectiveness of a cyclone. Additionally, the PM_{10} and $PM_{2.5}$ concentrations in the turbine exhaust stream are below those typically seen in a cyclone's exhaust stream. Thus, a cyclone would not lower emissions by any appreciable amount. Furthermore, research of emission control technology application data sets indicates a cyclone has not been used to control PM emissions from a comparable source. These factors indicate it would not be technically feasible to use a cyclone to control PM emissions from the turbine.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Based on the preceding analysis, the remaining control technologies are good combustion practices and use of gaseous fuels.

Step 4 – Evaluate Most Effective Controls

No control technologies are being excluded from consideration based on energy, environmental, or economic factors.

Step 5 – Select BACT

$PM/PM_{10}/PM_{2.5}$ BACT for CCGT-2 is determined to be the use of good combustion practices and use of gaseous fuels (natural gas or a natural gas/H_2 blend).

PRELIMINARY DETERMINATION SUMMARY

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine Iberville Parish, Louisiana
PSD-LA-863
March 12, 2025

Emission Unit	$PM_{2.5}/PM_{10}$ BACT Determination	$PM_{2.5}/PM_{10}$ BACT Limit	Averaging Period
CCGT-2 (EQT0002)	Use of gaseous fuel (pipeline quality natural gas or a blend of up to 50% H_2 and natural gas) and good combustion practices	$PM_{2.5}$: 0.008 lb/MMBtu PM_{10}: 0.008 lb/MMBtu	Three 1-hr test average

BACT for NO_X

EQT0002	CCGT-2	Combined Cycle Gas Turbine 2 with Duct Burners and HRSG

A turbine will emit NO_X when burning natural gas, or a blend of up to 50% hydrogen and natural gas, primarily due to the thermal and prompt NO_X generation mechanisms. The fuel does not contain appreciable amounts of organo-nitrogen compounds that result in fuel NO_X emissions. Thermal NO_X results from the high-temperature thermal dissociation and subsequent reaction of combustion air molecular nitrogen and oxygen. It tends to be generated in the high-temperature zone near the burner. The rate of thermal NO_X generation is affected by the following three factors: oxygen concentration, peak flame temperature, and the duration at peak flame temperature. As these three factors increase in value, the rate of thermal NO_X generation increases.

Prompt NO_X is generated at the flame front through the relatively fast reaction between combustion air nitrogen and oxygen molecules and fuel hydrocarbon radicals, which are intermediate species formed during the combustion process.

Step 1 – Identify All Control Technologies

Emission control methods identified as potential control options for NO_X from CCGT-2 include those listed below, including a combination of multiple controls, as applicable. Good combustion practices are assumed to be a baseline work practice. They are not addressed as a BACT option for NO_X since additional control levels beyond work practices are typically considered BACT.

1. Selective Catalytic Reduction (SCR)
2. Selective Non-Catalytic Reduction (SNCR)
3. Non-Selective Catalytic Reduction (NSCR)
4. Dry Low-NO_X Burners
5. Low- NO_X Burners
6. Water or Stream Injection
7. Catalytic Combustion (XONON)
8. EM_X^{TM} ($SCONOX^{TM}$)

SCR
SCR is a post-combustion treatment technology that promotes the selective catalytic chemical

reduction of NO_X (nitric oxide and nitrogen dioxide) to molecular nitrogen and water. SCR technology involves the mixing of a reducing agent (aqueous or anhydrous ammonia or urea) with NO_X–containing combustion gases, and the resulting mixture is passed through a catalyst bed, which serves to lower the activation energy of the NO_X reduction reactions. In the catalyst bed, the NO_X and ammonia contained in the combustion gas-reagent mixture are absorbed onto the SCR catalyst surface to form an activated complex, and then the catalytic reduction of NO_X occurs, resulting in the production of nitrogen and water from NO_X. An excess amount of reducing agent/ammonia is required to achieve the conversion to NO_X, though minimizing unreacted ammonia (known as ammonia slip) is desired. The nitrogen and water products of the SCR reaction are desorbed from the catalyst surface into the combustion exhaust gas passing through the catalyst bed. The treated combustion exhaust gas from the SCR catalyst bed, along with unreacted ammonia, is emitted to the atmosphere. SCR systems can effectively operate at a temperature above 350°F and below 1,100°F, with the specific temperature window dependent on the composition of the catalyst used in the SCR system.

SNCR

SNCR is a post-combustion treatment technology that is effectively a partial SCR system. A reducing agent (aqueous or anhydrous ammonia or urea) is mixed with NO_X–containing combustion gases, and a portion of the NO_X reacts with the reducing agent to form molecular nitrogen and water. As indicated by the name of this technology, SNCR, unlike SCR, does not utilize a catalyst to promote the chemical reduction of NO_X.

Because a catalyst is not used with SNCR, NO_X reduction reactions occur at high temperatures. SNCR typically requires thorough mixing of the reagent in the combustion chamber of an external combustion device because this technology requires at least 0.5 seconds of residence time at a temperature above 1,600°F and below 2,100°F. A combustion device equipped with SNCR technology may require multiple reagent injection locations because the optimum location (temperature profile) for reagent injection may change depending on the load at which the combustion device is operating. At temperatures below 1,600°F, the desired NO_X reduction reactions will not effectively occur, and much of the injected reagent will be emitted to the atmosphere along with the mostly uncontrolled NO_X emissions. At temperatures above 2,100°F, the desired NO_X reduction reactions will not effectively occur, and the ammonia or urea reagent will begin to react with available oxygen to produce additional NO_X emissions.

NSCR

NSCR is a post-combustion treatment technology that promotes the catalytic chemical reduction of NO_X (nitric oxide and nitrogen dioxide) to molecular nitrogen and water. NSCR technology has been applied to nitric acid plants and rich burn and stoichiometric internal combustion engines to reduce NO_X emissions. NSCR technology uses a reducing agent (hydrocarbon, hydrogen, or CO) either inherent in the exhaust gas due to rich combustion conditions or injected into the exhaust gas, to react with a portion of the NO_X contained in the source's exhaust gas in the presence of a catalyst to generate molecular nitrogen and water. NSCR systems can effectively operate at a temperature above 725°F and below 1,200°F, with

the specific temperature window dependent on the source type and composition of the catalyst used in the NSCR system.

Dry Low NO_X Burners (DLN)
DLN combustor technology premixes air and a lean fuel mixture prior to injection into the combustion turbine and significantly reduces peak flame temperatures and thermal NO_X formation. Conventional combustors are diffusion controlled; fuel and air are injected separately.

Low NO_X Burners (LNB)
LNBs are available in various configurations and burner types. They incorporate one or more of the following concepts: lower flame temperatures, fuel rich conditions at the maximum flame temperature, and decreased residence times for oxidation conditions. These burners are often designed so that fuel and air are pre-mixed prior to combustion, resulting in lower and more uniform flame temperatures. Pre-mix burners may require the aid of a blower to mix the fuel with air before combustion takes place.

LNBs use staged fuel or air combustion, which involves creating a fuel rich zone to start combustion and stabilize a burner's flame, followed by a fuel lean zone to complete combustion, and reduce the burner's peak flame temperature.

Catalytic Combustion (XONON)
Fuel and air are mixed thoroughly before entering the catalyst, which promotes chemical reactions and therefore releases the heat of combustion. Catalytic combustion can take place at equivalence ratios that are well below the lean extension limit encountered in conventional combustion systems. At such low temperatures, the NO_X levels are reduced dramatically.

Water or Steam Injection
Water or steam injection is a traditional method of lowering NO_X formation in diffusion flame combustion systems, in which fuel and air are mixed in the combustion zone, resulting in a tendency to form "hot spots." In these systems, the injection of water or steam into the flame area of the combustor is an effective means to combat the formation of thermal NO_X by quenching hot spots and reducing the temperature of the flame zone.

SCONOX/EM_X
SCONOX or EM_X is another catalyst-based post-combustion control, which simultaneously oxidizes CO to CO_2, VOC to CO_2 and water, and NO to NO_2, subsequently adsorbing the NO_2 onto the surface of a catalyst where a chemical reaction removes it from the exhaust stream. The optimal temperature window for operation of the SCONOX catalyst is 300-700°F. This technology has not been used and is not currently offered for large turbines.

Step 2 – Eliminate Technically Infeasible Options

SNCR and NSCR
SNCR and NSCR technologies have limitations that make them inappropriate for application

to combustion turbines. SNCR requires a flue gas exit temperature in the range of 1,300 to 2,100°F, with an optimum operating temperature zone between 1,600 and 1,900°F. Combined-cycle turbines have exhaust temperatures much lower than the range required for SNCR. Therefore, additional fuel combustion or a similar energy supply would be needed to create exhaust temperatures compatible with SNCR operation. This temperature restriction and related economic considerations make SNCR infeasible for the proposed combustion turbine. NSCR is only effective in controlling fuel-rich reciprocating engine emissions and requires the combustion gas to be nearly depleted of oxygen (<4% by volume) to operate properly. Since combustion turbines operate with high levels of excess oxygen (typically 14 to 16% O_2 in the exhaust), NSCR is infeasible for the proposed CCGT-2.

Catalytic Combustion (XONON)
This technology is not commercially available for a large unit. All commercial installations to date have been on small turbines in the 1-2 MW size range. Thus, XONON is determined to be technically infeasible for the proposed CCGT-2.

SCONOX/EM_X
This technology has not been used and is not currently offered for large gas-fired turbines. Additionally, this technology has not been used as BACT for large gas-fired combined cycle combustion turbines per the RBLC Clearinghouse search conducted. Therefore, this technology has been eliminated from further discussion.

SCR, dry low NO_X burners, low NO_X burners, and water or steam injection are considered technically feasible control options for the turbine.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The technically feasible control options are ranked below according to their control effectiveness:

Rank	Control Technology	NO_X Emission Levels
1	SCR + Dry Low NO_X Burners	2 ppmvd
2	SCR	2 ppmvd
3	Dry Low NO_X Burners	9 ppmvd
4	Water or Steam Injection	25 ppmvd
5	Low NO_X Burners	30 ppmvd

Step 4 – Evaluate Most Effective Controls

No controls are being excluded from consideration based on energy, environmental, or economic factors.

Step 5 – Select BACT

NO_X BACT for CCGT-2 is determined to be the use dry low NO_X burners with SCR, which is considered the highest ranked control option, along with good combustion practices.

Emission Unit	NO_X BACT Determination	NO_X BACT Limit	Averaging Period
CCGT-2 (EQT0002)	Dry low-NO_X combustor design, SCR, and good combustion practices	2.0 ppmvd @15% O_2	24-hr rolling average based on a 1-hour average

BACT for CO

EQT0002	CCGT-2	Combined Cycle Gas Turbine 2 with Duct Burners and HRSG

CO emissions from the turbine will be a result of incomplete combustion. Specifically, CO results when there is insufficient residence time at high temperatures or incomplete mixing in the combustion zone to complete the final step in the oxidation of carbon from CO to CO_2. Further, control technologies for NO_X emissions, such as low-NO_X burners, may increase CO emissions.

Step 1 – Identify All Control Technologies

The following are available CO emission control technologies for the turbine.

1. Good Combustion Practices
2. Catalytic Oxidation

Good Combustion Practices

Good combustion practices for a gaseous fuel-fired combustion device consist of properly setting and controlling the air-to-fuel ratio and ensuring appropriate combustion zone residence time, temperature, and turbulence parameters essential to achieving low emission levels for all products of combustion, including NO_X, CO, VOC, PM_{10}, and $PM_{2.5}$. Incomplete combustion of fuel hydrocarbons can occur because of improper combustion mechanisms, resulting from poor burner/combustion device design, operation, and/or maintenance. However, combustion devices (e.g., turbines, heaters, boilers) are designed and typically operated to maximize fuel combustion efficiency so that fuel usage costs are minimized while process heating performance is maximized. Good combustion practices can be achieved by following a combustion device manufacturer's operating procedures and guidelines.

Catalytic Oxidation

Catalytic oxidation uses catalysts, such as the precious metals platinum, palladium, or rhodium, without adding any chemical reagents to reduce the temperature at which CO oxidizes to CO_2. The effectiveness of catalytic oxidation is dependent on the exhaust stream temperature and the presence of potentially poisoning contaminants in the exhaust stream. The amount of catalyst volume depends upon the exhaust stream flow rate, CO content, temperature, and desired CO removal efficiency. The catalyst will experience activity loss over time due to physical deterioration. Therefore, the catalyst must be periodically replaced. Catalyst life varies from manufacturer to manufacturer, but three- to six-year windows are not uncommon. Periodic testing of the catalyst is necessary to monitor its activity (i.e., oxidation-promoting effectiveness) and predict its remaining life.

Step 2 – Eliminate Technically Infeasible Options

Good combustion practices and catalytic oxidation are considered technically feasible options for the turbine.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The technically feasible control options are ranked below according to their control effectiveness:

Rank	Control Technology	CO Emission Levels
1	Catalytic Oxidation	90%
2	Good Combustion Practices	Baseline

Step 4 – Evaluate Most Effective Controls

No controls are being excluded from consideration based on energy, environmental, or economic factors.

Step 5 – Select BACT

CO BACT for CCGT-2 is determined to be the use of catalytic oxidation with good combustion practices.

Emission Unit	CO BACT Determination	CO BACT Limit	Averaging Period
CCGT-2 (EQT0002)	Catalytic oxidation and good combustion practices	2.0 ppmvd @15% O_2	24-hr rolling average based on a 1-hour average

BACT for VOC

EQT0002	**CCGT-2**	**Combined Cycle Gas Turbine 2 with Duct Burners and HRSG**

CCGT-2 will emit VOC due to the incomplete oxidation of hydrocarbons present in the gaseous fuel. However, the low molecular weight characteristic of the hydrocarbons in the fuel promotes low levels of VOC emissions from the turbine.

Step 1 – Identify All Control Technologies

The following are available VOC emission control technologies for the turbine.

1. Good Combustion Practices
2. Catalytic Oxidation

Step 2 – Eliminate Technically Infeasible Options

Good combustion practices and catalytic oxidation are considered technically feasible options for the turbine.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The technically feasible control options are ranked below according to their control effectiveness:

Rank	Control Technology	VOC Emission Levels
1	Catalytic Oxidation	90%
2	Good Combustion Practices	Baseline

Step 4 – Evaluate Most Effective Controls

No controls are being excluded from consideration based on energy, environmental, or economic factors.

Step 5 – Select BACT

VOC BACT for CCGT-2 is determined to be the use of catalytic oxidation with good combustion practices.

Emission Unit	VOC BACT Determination	VOC BACT Limit	Averaging Period
CCGT-2 (EQT0002)	Catalytic oxidation and good combustion practices	1.0 (no duct firing) and 2.0 (with duct firing) ppmvd @15% O_2	Three 1-hr test average without and with duct firing, respectively

BACT for CO_2e

EQT0002	CCGT-2	Combined Cycle Gas Turbine 2 with Duct Burners and HRSG

Natural gas combustion in a gas turbine produces carbon dioxide (CO_2) and nitrous oxide (N_2O) emissions. During the combustion process, almost all of the fuel carbon is converted to CO_2. Methane (CH_4), a product of unburned fuel, is also found in the exhaust gas.

40 CFR 60 Subpart TTTTa, Standards or Performance for Greenhouse Gas (GHG) Emissions for Modified Coal-Fired Steam Electric Generating Units, became effective on July 8, 2024, and established emission standards and compliance schedules for the control of GHG emissions from a stationary combustion turbine that is constructed after May 23, 2023. CCGT-2 will be subject to an initial "phase one" CO_2 emission standard for new base load turbines based on efficient design and operation of combined cycle turbines.

Step 1 – Identify All Control Technologies

The following are available GHG emission control technologies for the turbine.

1. Carbon Capture and Sequestration (CCS)
2. Energy Efficiency Measures

Carbon Capture and Sequestration (CCS)
CCS involves post-combustion capture of CO_2 emissions. Carbon capture systems produce a concentrated stream of CO_2, which is then compressed for transport to a suitable disposal site for deep underground storage in geological formations, decreasing emissions of CO_2 to the atmosphere. Carbon capture can be achieved with low pressure scrubbing of CO_2 from the exhaust stream with either solvents (e.g., amines or ammonia), solid sorbents, or membranes. However, only solvents have been used to-date on a commercial scale, while the others are in the research and development phase.

Since the majority of GHG emissions from a combustion turbine are in the form of CO_2 emissions, decreasing CO_2 emissions would decrease GHG emission by nearly the same fraction.

Energy Efficient Measure
Increasing the efficiency of the turbine directly decreases GHG emissions as less fuel is combusted per unit output. In general, turbines which operate at higher temperatures (i.e., larger turbines) have the highest efficiencies. Energy efficiency measures may include use of thermally efficient turbines, use of gaseous fuels, use of good combustion practices, use of combustion cooling air, and use of insulation.

- Thermally efficient: The proposed CCGT-2 is a combined cycle gas turbine that will be equipped with a heat steam recovery generator (HRSG).
- Gaseous fuels: Fuels containing less carbon have lower potential CO_2 and CH_4 emissions. Choosing a less carbonaceous fuel will decrease CO_2 and CH_4 emissions, as fewer carbon atoms are available. The proposed CCGT-2 will combust natural gas or a blend of up to 50% hydrogen and natural gas.
- Good combustion practices
- Combustion cooling air: Turbine energy efficiency can be improved by cooling the combustion air entering the turbine during the summer months. Combustion air can be cooled using heat exchanger systems to maximize the expansion of the air molecules and enhance the work the expanding gases perform on the turbine blades.
- Insulation: Heat losses from the turbine can be minimized through proper selection and use of refractory and insulation materials. Minimizing heat loss helps increase the efficiency of a combustion system.

Step 2 – Eliminate Technically Infeasible Options

The technical feasibility of GHG control technologies for CCGT-2 is summarized below.

CCS
CCS must be "available" and "applicable" for the project to be considered technically feasible. CCS consists of three stages: (1) capturing and concentration CO_2 from the gas stream, (2) compression and transport to a storage facility via pipeline, and (3) injection and storage of the CO_2 into available underground sequestration sites such as old oil and gas wells or other geological formations. If any of the three stages of CCS cannot meet both criteria for technical feasibility, CCS cannot constitute BACT.

CCS is a developing technology that has a few full scale, demonstration plants to confirm the technology as a viable BACT selection. CCS projects have been announced, including some in Louisiana. However, these projects are in the early stages of planning or execution and do not serve to demonstrate that CCS is technically feasible (available and applicable) for streams containing dilute concentrations of CO_2. The technical feasibility of carbon capture, transport, and storage is further detailed below.

Post-Combustion Capture
Post-combustion capture processes are in various stages of development, including absorption, adsorption, and gas separation membrane technologies. Absorption is the most widely used and the only commercially available technology of the three. Adsorption uses

amine or monoethanolamine (MEA) solvents to absorb and separate CO_2 from the other flue gases.[10] Steam is used to regenerate amines saturated with CO_2 for recycle, and the captured CO_2 is compressed for transport.

While carbon capture technology may be generally commercially available, it is not "applicable" to the turbine because of the dilute CO_2 concentrations of the exhaust. The air used for combustion contains over 75% nitrogen, making the CO_2 concentration in the exhaust gas 5%, depending on the amount of excess air and carbon in the fuel. The low concentration and low pressure of the combustion source exhaust complicates the absorption and desorption of the CO_2, making the capture significantly more difficult than that from highly concentrated steams. In contrast, the concentrations of CO_2 in coal-fired, IGCC utility boiler streams, for which the EPA determined in its proposed Electric Utility GHG New Source Performance Standards (NSPS) that CCS is technically feasible and economical, are on the order of 30-32%.

The EPA has noted that the agency is unaware of any demonstrations of natural gas combined cycle turbines implementing CCS that would justify setting a national standard[11]. In addition, the NETL Carbon Capture Project Map does not show any full-scale natural gas post-combustion capture projects as of October 2022.[12] Camellia is unaware of any CCS add-on controls that have been demonstrated at this scale on a highly dilute CO_2 stream similar to the CCGT-2 exhaust. Difficulties that would be expected include 1) large volumes of exhaust gas to treat with low CO_2 concentrations, and 2) other contaminants such as NO_X, PM, and SO_2 may degrade the capture system and absorption reagents.[13] Therefore, while post-combustion capture appears to be generally commercially available, post-combustion capture does not appear to be "applicable" (cannot be reasonably applied) for the turbine given the relatively low concentration of CO_2 in the exhaust streams. Therefore, carbon capture is not technically feasible.

Transport

After post-combustion capture, CO_2 must be transported to the sequestration location. This requires a dedicated pipeline or a reliable third-party pipeline to continuously accept capture CO_2 throughout the lifetime of the facility, especially if a given source is required to accept continuous CO_2 emission limitations reflecting CCS as BACT. While CO_2 pipelines exist in Louisiana (see Denbury EOR operations[14]), and Camellia could theoretically transport CO_2 from the site to the nearest pipeline, serious logistical issues could cause significant delays

[10] U.S. EPA Region 6, Statement of Basis – Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Calpine Corporation, Deer Park Energy Center (DPEC), LLC (August 2012).

[11] See, U.S. EPA, "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units; Proposed Rule" (Sep. 20, 2013), Electronic source: http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf

[12] https://www.netl.doe.gov/carbon-management/carbon-capture/ccmap

[13] https://pure.hw.ac.uk/ws/portalfiles/portal/9277103/Manuscript_revised.pdf

[14] The Denbury Green pipeline extends from Donaldsonville westward towards Lake Charles and into Texas' Hastings Field (https://www.denbury.com/operations/operations-overview/gulf-coast-region/Pipelines/default.aspx)

(e.g., securing right-of-way permits, establishing contracts with the pipeline company transporting CO_2, and allowing for the environmental review for the pipeline connection to the CO_2 pipeline). It also assumes that an existing CO_2 pipeline has sufficient capacity to accept CO_2 from Camellia Power Unit 2 on a continuous basis for the life of the facility.

Given the transport issues described above, although pipeline transport appears commercially available, transport of captured CO_2 cannot be reasonably applied for the turbine.

Storage

Camellia only considers storage techniques with the purpose of long-term storage as an appropriate GHG BACT technology selection. Technologies exist to operate a sequestration injection well. However, permanent geological sequestration of CO_2 is not fully demonstrated technology. The National Energy Technology Laboratory (NETL) has several research and demonstration projects underway to evaluate long-term storage viability. However, large-scale (greater than 1 million metric tons CO_2 injected) sequestration projects are still in the process of testing and development. The long-term impacts of these projects are currently unclear. The results thus far have been mixed, as some projects have been successful while others have encountered significant drawbacks,[15] indicating that CCS storage should not be considered sufficiently demonstrated in practice to qualify as an appropriate BACT technology. Key challenges for storage that must be demonstrated over longer periods of time include:

- Verification that CO_2 will be contained in the target geologic formations;
- Development of technologies to quantify potential releases;
- Long term monitoring to track the CO_2 plume to verify that it stays within the intended containment zone during and after project.

Even if storage technologies were further developed, Camellia would need to find a suitable sequestration site (aside from EOR, discussed below), acquire rights for injection, further study the injection site for suitable geologic formations, and develop an appropriate monitoring scheme for long-term verification of sequestration. Any such sequestration site is hypothetical and is not appropriate to be considered as BACT for Camellia Power Unit 2.

An alternative to stand-alone, dedicated sequestration wells for CO_2 storage, CO_2 is commonly used for enhanced oil recovery (EOR). However, EOR is not considered by the EPA[16] as permanent sequestration unless it complies with 40 CFR 98, Subpart RR. To comply with Subpart RR, an EOR operation must include CO_2 injection wells that are permitted as Class VI under the Underground Injection Control Program, or hold a monitoring, reporting, and verification (MRV) plan approved by EPA.[17] EPA distinguishes between enhanced recovery ("ER"), the principal purpose of which is EOR, and ER, the

[15] https://ieefa.org/resources/carbon-capture-ccs-ccus-ccu
[16] Federal Register : : Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, (October 23, 2015)
[17] 40 C.F.R § 98.440(c)(1)-(2)

principal purpose of which is geologic sequestration ("GS").

Given EPA's requirement for the sequestration location to be Subpart RR compliant, the number of suitable injection locations is quite limited, even though CO_2 sequestration for EOR is fairly common across the United States. The limited number of Subpart RR compliant storage locations adds to the transportation feasibility issues. Constructing a pipeline to any of these locations would not only add substantial cost, but it would also require substantial environmental permitting and right-of-way access. Additionally, a contractual agreement would need to be secured with a Subpart RR-compliant well operator.[18]

Each of the components of CCS, which are capture, transport, and storage, are considered to be technically infeasible for the reasons above.

Energy efficient measures are considered technically feasible options for controlling GHG emissions from the turbine. Additionally, a review of the RBLC confirms that CCS has not been specified as BACT for similar sources.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Based on the preceding analysis, the remaining control technology is energy efficiency measures.

Step 4 – Evaluate Most Effective Controls

No control technologies are being excluded from consideration based on energy, environmental, or economic factors.

Step 5 – Select BACT

GHG BACT for CCGT-2 is determined to be the use of energy efficiency measures, including:

- Use of thermally efficient turbines;
- Using gaseous fuels for improved combustion efficiency;
- Using good combustion practices.

[18] EPA's response to public comments in the La Paloma GHG permitting action correctly describes any EPA-imposed requirement to arrange for EOR disposal of CO2 as an "attempt to arrange a contractual marriage through a BACT determination." U.S. EPA also notes in the La Paloma response that requiring CCS would "require the applicant to clear numerous logistical hurdles such as obtaining contracts for offsite land acquisition for pipeline right-of-way, construction of the transportation infrastructure, and develop a customer(s) who is willing to purchase the CO2." EPA also notes that the actual price of CO2 could vary depending on a number of factors, including CO2 availability in the area, the nature of the EOR reservoir, and the price per barrel of oil. EPA concludes that, for the La Paloma project, that "these obstacles alone make CCS for this specific site and project economically infeasible and possibly even technically infeasible." The same holds true for this project. (https://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/la-paloma-response11062013.pdf)

The CO_2e BACT limit is determined to be 800 lb CO_2/MWh-gross based on a 12-month rolling average, which is the 40 CFR 60 Subpart TTTTa Phase 1 emission limit for base load combustion turbines.

Emission Unit	CO_2e BACT Determination	CO_2e BACT Limit	Averaging Period
CCGT-2 (EQT0002)	Use of gaseous fuel (pipeline quality natural gas or a blend of up to 50% H_2 and natural gas), thermally efficient turbines, and good combustion practices	800 lb/MWh-gross	12-month rolling average

BACT for H_2SO_4 Mist

EQT0002	CCGT-2	Combined Cycle Gas Turbine 2 with Duct Burners and HRSG

SO_3 is emitted as a result of the oxidation of the sulfur in the fuel. Natural gas does contain a small amount of sulfur, including sulfides and sulfur-containing mercaptan, which is added to natural gas to permit leak detection. Therefore, a small amount of SO_3 is produced in the combustion of natural gas. Additionally, a small percentage of the SO_2 in the flue gas oxidizes to SO_3 when passing across the catalyst (oxidation and SCR). Sulfuric acid mist emissions are formed as a result of the SO_3 combining with water to form H_2SO_4.

Step 1 – Identify All Control Technologies

The following are available H_2SO_4 emission control technologies for the turbine.

1. Good Combustion Practices
2. Use of Low Sulfur Fuels
3. Flue Gas Desulfurization (FGD) Technologies
4. Dry Sorbent Injection

Use of Low Sulfur Fuels
Limiting the amount of sulfur in fuel is a common practice for natural gas-fired power plants. Minimizing the amount of sulfur in the fuel combusted will minimize the amount of sulfur able to form sulfuric acid mist. The practical limitation is considered region-specific, depending on the specifications of the natural gas supplied to the facility via pipeline.

FGD Technologies
SO_2 and H_2SO_4 can be removed from exhaust streams by using an alkaline reagent to form sulfite and sulfate salts. The reaction of SO_2 with the alkaline chemical can be performed using either a wet or dry contact system. FGD wet scrubbers typically employ sodium, calcium, or dual-alkali reagents using packed or spray towers. Wet FGD systems generate

wastewater and wet sludge streams requiring treatment and disposal. In dry FGD systems, an alkaline slurry is injected into the combustion process exhaust stream. The liquid sulfite/sulfate salts that form from the reaction of the alkaline slurry with SO_2 are dried by heat contained in the exhaust stream and subsequently removed by downstream particulate control equipment.

Dry Sorbent Injection
Dry sorbent injection is a post-combustion technology involving the reaction of a calcium or sodium-based sorbent with SO_2 and SO_3. The reduced availability of SO_2 and SO_3 in the exhaust stream reduces H_2SO_4 formation, thereby reducing H_2SO_4 emissions.

Step 2 – Eliminate Technically Infeasible Options

The technical feasibility of H_2SO_4 control technologies for CCGT-2 is summarized below.

FGD Technologies and Dry Sorbent Injection
There have been no applications of FGD scrubbers on natural gas-fired combustion turbines due to low SO_2 and H_2SO_4 emissions. In addition, combustion turbines have high exhaust gas flow rates. The low SO_2 and H_2SO_4 emissions combined with the large exhaust gas volume results in very low concentrations of SO_2 and H_2SO_4. Due to the low SO_2 and H_2SO_4 concentrations in the exhaust gas, neither the FGD scrubber nor dry sorbent injection would provide any measurable emission reduction and are, therefore, technically infeasible.

Good combustion practices and use of low sulfur fuels are considered technically feasible options for the turbine.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Based on the preceding analysis, the remaining control technologies are good combustion practices and use of gaseous fuels.

Step 4 – Evaluate Most Effective Controls

No control technologies are being excluded from consideration based on energy, environmental, or economic factors.

Step 5 – Select BACT

H_2SO_4 BACT for CCGT-2 is determined to be the use of good combustion practices and the use of low sulfur fuel, including pipeline quality natural gas and a blend of up to 50% hydrogen and pipeline quality natural gas. The H_2SO_4 BACT limit is 0.00623 grains/dscf.

Emission Unit	H_2SO_4 BACT Determination	H_2SO_4 BACT Limit	Averaging Period
CCGT-2 (EQT0002)	Use of gaseous fuel (pipeline quality natural gas or a blend of up to 50% H_2 and natural gas) and good combustion practices	0.00623 grains/dscf	N/A

BACT for CCGT-2 During Startup or Shutdown (SU/SD)

BACT for $PM_{2.5}/PM_{10}$, CO_2e, and H_2SO_4

SCN0002	CCGT-2-SUSD	Combined Cycle Gas Turbine 2 – Startup and Shutdown

The proposed CCGT-2 will operate in "Normal Operating Mode" or "Startup and Shutdown Mode (SU/SD)." Startup mode begins when fuel is first introduced and a combustion flame has been established in the gas turbine. Startup mode ends and normal operating mode begins when ammonia injection is in service and startup emissions having finished routing through the continuous emission monitoring system (CEMS). Normal operating mode ends and shutdown mode begins when ammonia injection is no longer in service as intended for shutdown (i.e., shutdown of the ammonia system is not caused by a system failure). Shutdown mode ends when the gas turbine has flamed out and the fuel valve is closed.

During SU/SD operations, NO_X, CO, and VOC concentrations can be higher than levels during normal operating mode. The Auxiliary Boiler will provide steam to assist in minimizing emissions and durations of SU/SD.

SU/SD conditions vary compared to normal operations, affecting some potential control options. These conditions do not affect the control options for PM_{10}, $PM_{2.5}$, GHG, and H_2SO_4 emissions.

Therefore, $PM/PM_{10}/PM_{2.5}$ BACT for CCGT-2-SUSD is determined to be the use of good combustion practices and use of gaseous fuels (natural gas and a natural gas/H_2 blend).

Emission Unit	$PM_{2.5}/PM_{10}$ BACT Determination	$PM_{2.5}/PM_{10}$ BACT Limit	Averaging Period
CCGT-2-SUSD (SCN0002)	Use of gaseous fuel (pipeline quality natural gas or a blend of up to 50% H_2 and natural gas) and good combustion practices	$PM_{2.5}$: 0.008 lb/MMBtu PM_{10}: 0.008 lb/MMBtu	Three 1-hr test average

GHG BACT for CCGT-2-SUSD is determined to be the use of energy efficiency measures, including:

- Use of thermally efficient turbines;
- Using gaseous fuels for improved combustion efficiency;

- Using good combustion practices.

The CO_2e BACT limit for CCGT-2-SUSD is determined to be 800 lb CO_2/MWh-gross based on a 12-month rolling average, which is the 40 CFR 60 Subpart TTTTa Phase 1 emission limit for base load combustion turbines.

Emission Unit	CO_2e BACT Determination	CO_2e BACT Limit	Averaging Period
CCGT-2-SUSD (SCN0002)	Use of gaseous fuel (pipeline quality natural gas or a blend of up to 50% H_2 and natural gas), thermally efficient turbines, and good combustion practices	800 lb/MWh-gross	12-month rolling average

H_2SO_4 BACT for CCGT-2-SUSD is determined to be the use of good combustion practices and the use of low sulfur fuel, including pipeline quality natural gas and a blend of up to 50% hydrogen and pipeline quality natural gas. The H_2SO_4 BACT limit is 0.00623 grains/dscf.

Emission Unit	H_2SO_4 BACT Determination	H_2SO_4 BACT Limit	Averaging Period
CCGT-2-SUSD (SCN0002)	Use of gaseous fuel (pipeline quality natural gas or a blend of up to 50% H_2 and natural gas) and good combustion practices	0.00623 grains/dscf	N/A

BACT for NO_X

SCN0002	CCGT-2-SUSD	Combined Cycle Gas Turbine 2 – Startup and Shutdown

NO_X BACT for CCGT-2 during normal operation is determined to be the use Dry Low NO_X Burners with SCR along with good combustion practices. During normal operations, CCGT-2 will operate in a lean pre-mix mode, where fuel and air are mixed together, as opposed to how CCGT-2 will operate during SU/SD operations. Therefore, during SU/SD, NO_X emissions have the potential to be higher than during premix and normal operating mode. SU/SD emissions are estimated based on vendor provided data. Also, the SCR system is designed for normal operating mode. Although some NO_X reductions may be realized from the SCR during SU/SD mode, it is difficult to quantify and cannot be guaranteed. To minimize NO_X emissions during SU/SD, the duration of events will be minimized and the manufacturer's recommended procedures will be followed.

NO_X BACT for CCGT-2-SUSD is determined to be the use of good combustion practices.

PRELIMINARY DETERMINATION SUMMARY

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine Iberville Parish, Louisiana
PSD-LA-863
March 12, 2025

BACT for CO and VOC

SCN0002	**CCGT-2-SUSD**	**Combined Cycle Gas Turbine 2 – Startup and Shutdown**

CO and VOC BACT for CCGT-2 for normal operations is determined to be the use of catalytic oxidation with good combustion practices. High temperatures are required for the oxidation catalyst to work most efficiently. As the turbine progresses through the different stations of startup, the effectiveness of the oxidation catalyst will vary and, therefore, emissions cannot be guaranteed. SU/SD emissions have been estimated based on vendor provided data. CO and VOC emissions will be higher during startup and shutdown operations.

CO and VOC BACT for CCGT-2-SUSD are determined to be the use of good combustion practices.

BACT Review for Auxiliary Boiler

BACT for $PM_{2.5}/PM_{10}$

EQT0001	**BOIL-2**	**Auxiliary Boiler**

BOIL-2 will emit PM_{10} and $PM_{2.5}$ comprised of filterable and condensable portions. A gaseous fuel combustion device can emit PM_{10} and $PM_{2.5}$ due to the incomplete combustion of higher molecular weight hydrocarbons present in the device's gaseous fuel. However, the Boiler will combust pipeline quality natural gas and a blend of up to 50% hydrogen and natural gas. Therefore, elevated PM_{10} and $PM_{2.5}$ emissions from the Boiler due to the incomplete combustion of high molecular weight hydrocarbons are not expected to occur. Additionally, the referenced fuels will contain low levels of sulfur, further minimizing the generation of PM_{10} and $PM_{2.5}$ (condensable PM).

Step 1 – Identify All Control Technologies

The following are available PM emission control technologies for the Auxiliary Boiler:

1. Good Combustion Practices and Use of Gaseous Fuels
2. Electrostatic Precipitator (ESP)
3. Wet Scrubber
4. Filter
5. Cyclone

Step 2 – Eliminate Technically Infeasible Options

ESP

PM emitted by the BOIL-2 is estimated to be PM_{10} and $PM_{2.5}$ only, which is a characteristic

that would limit the control effectiveness of an ESP. Additionally, the PM_{10} and $PM_{2.5}$ concentrations in the exhaust stream are below those typically seen in an ESP's exhaust stream. Thus, an ESP would not lower emissions by any appreciable amount. Furthermore, research of emission control technology application data sets indicates an ESP has not been used to control PM emissions from a comparable source. These factors indicate that it would not be technically feasible to use an ESP to control PM emissions from the boiler.

Filter

The PM_{10} and $PM_{2.5}$-only profile of BOIL-2 PM emissions would limit the control effectiveness of a filter. Additionally, the PM_{10} and $PM_{2.5}$ concentrations in the exhaust stream are below those typically seen in a filter's exhaust stream. Thus, a filter would not lower emissions by any appreciable amount. Furthermore, research of emission control technology application data sets indicates a filter has not been used to control PM emissions from a comparable source. These factors indicate it would not be technically feasible to use a filter to control PM emissions from the boiler.

Wet Scrubber

The PM_{10} and $PM_{2.5}$-only profile of the boiler PM emissions indicates a wet scrubber would require a considerable pressure drop to effectively reduce the PM emissions. Additionally, the PM_{10} and $PM_{2.5}$ concentrations in the boiler exhaust stream are below these typically seen in a wet scrubber's exhaust stream. Furthermore, the liquid carryover in the exhaust stream from a wet scrubber contains dissolved and suspended solids, which would result in a new PM emission mechanism, reducing any negligible PM_{10} and $PM_{2.5}$ control effectiveness of the wet scrubber. Moreover, research of emission control technology application data sets indicates a wet scrubber has not been used to control PM emissions from a comparable source. These factors indicate it would not be technically feasible to use a wet scrubber to control PM emissions from the boiler.

Cyclone

The PM_{10} and $PM_{2.5}$-only profile of the boiler PM emissions would limit the control effectiveness of a cyclone. Additionally, the PM_{10} and $PM_{2.5}$ concentrations in the boiler exhaust stream are below those typically seen in a cyclone's exhaust stream. Thus, a cyclone would not lower emissions by any appreciable amount. Furthermore, research of emission control technology application data sets indicates a cyclone has not been used to control PM emissions from a comparable source. These factors indicate it would not be technically feasible to use a cyclone to control PM emissions from the boiler.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Based on the preceding analysis, the remaining control technologies are good combustion practices and use of gaseous fuels.

Step 4 – Evaluate Most Effective Controls

No control technologies are being excluded from consideration based on energy,

environmental, or economic factors.

Step 5 – Select BACT

$PM/PM_{10}/PM_{2.5}$ BACT for BOIL-2 is determined to be the use of good combustion practices and use of gaseous fuels (natural gas and a natural gas/H_2 blend).

Emission Unit	$PM_{2.5}/PM_{10}$ BACT Determination	$PM_{2.5}/PM_{10}$ BACT Limit	Averaging Period
BOIL-2 (EQT0001)	Use of gaseous fuel (pipeline quality natural gas or a blend of up to 50% H_2 and natural gas) and good combustion practices	$PM_{2.5}$: 0.0074 lb/MMBtu PM_{10}: 0.0074 lb/MMBtu	Annual average during normal operations

BACT for NO_X

EQT0001	BOIL-2	Auxiliary Boiler

BOIL-2 will emit NO_X primarily due to the thermal and prompt NO_X generation mechanisms because the fuel does not contain appreciable amounts of organo-nitrogen compounds that result in fuel NO_X emissions. Thermal NO_X results from the high temperature thermal dissociation and subsequent reaction of combustion air nitrogen and oxygen, and it tends to be generated in the high temperature zone near the burner of an external combustion device. The rate of thermal NO_X generation is affected by the following three factors: oxygen concentration, peak flame temperature, and the duration at peak flame temperature. As these three factors increase in value, the rate of thermal NO_X generation increases.

Prompt NO_X is generated at the flame front through the relatively fast reaction between combustion air nitrogen and oxygen molecules and fuel hydrocarbon radicals, which are intermediate species formed during the combustion process. Prompt NO_X may represent a meaningful portion of the NO_X emissions resulting from low NO_X burners (LNBs) and ultra-low NO_X burners (ULNBs).

Step 1 – Identify All Control Technologies

Emission control methods identified as potential options for controlling NO_X emissions from the Boiler include those listed below. Good combustion practices are assumed to be a baseline work practice. They are not addressed as a BACT option for NO_X since additional control levels beyond work practices are typically considered BACT.

1. Selective Catalytic Reduction (SCR)
2. Selective Non-Catalytic Reduction (SNCR)
3. Non-Selective Catalytic Reduction (NSCR)
4. Low-NO_X Burners (LNB) and Ultra Low-NO_X Burners (ULNB)

5. Flue Gas Recirculation

Step 2 – Eliminate Technically Infeasible Options

SNCR and NSCR

SNCR and NSCR technologies have limitations that make them inappropriate for application to boilers. SNCR requires a flue gas exit temperature in the range of 1,300 to 2,100°F, with an optimum operating temperature zone between 1,600 and 1,900°F. The auxiliary boiler will have exhaust temperatures much lower than the range required for SNCR. Therefore, additional fuel combustion or a similar energy supply would be needed to create exhaust temperatures compatible with SNCR operation. This temperature restriction and related economic considerations make SNCR infeasible for the proposed auxiliary boiler. NSCR is only effective in controlling fuel-rich reciprocating engine emissions and requires the combustion gas to be nearly depleted of oxygen (<4% by volume) to operate properly. Since auxiliary boiler will operate with high levels of excess oxygen, NSCR is infeasible for the proposed BOIL-2.

SCR, ultra low NO_X burners, low NO_X burners, and flue gas recirculation are considered technically feasible control options for the boiler.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The technically feasible control options are ranked below according to their control effectiveness:

Rank	Control Technology	NO_X Emission Levels
1	SCR	≤ 5 ppm
2	ULNB	7-20 ppm
3	LNB	30 ppm
4	FGR	30-50%

Step 4 – Evaluate Most Effective Controls

SCR is the top-ranked control option and is the top BACT control for small gas-fired boilers in the RBLC database. Per USEPA,[19] SCR technology can achieve >70% reduction efficiencies for NO_X concentrations as low as 20 ppm. However, per the RBLC database, SCR is rarely used for small gas-fired boilers and is not typically used for boilers similarly sized to the proposed BOIL-2.

SCR technology results in unreacted ammonia or ammonia slip, which is typically permitted between 2 and 10 ppm.

[19] USEPA Air Pollution Control Technology Fact Sheet, Selective Catalytic Reduction (SCR). https://www3.epa.gov/ttncatc1/dir1/fscr.pdf

Per the RBLC database search results, ultra-low NO_X burners are a top control for NO_X emissions from natural gas-fired boilers. Per the search, NO_X emissions from natural gas-fired boilers range from 0.006 lb/MMBtu to 0.01 lb/MMBtu. Camellia intends to equip the Boiler with ULNB, which have a vendor provided NO_X emission factor of 0.01 lb/MMBtu; therefore; BOIL-2 will have an estimated NO_X emission rate of 3.5 tpy. The installation of SCR to reduce the NO_X emission factor to 0.006 lb/MMBtu would only result in a NO_X reduction of 1.40 tpy NO_X. Also, SCR NO_X emissions reductions may be lessened when the technology follows other NO_X controls such as ULNB. Considering the cost to install and operate SCR on a boiler of this size and the limited additional environmental benefits from doing such, application of SCR is rejected as BACT for BOIL-2. The next highest ranked NO_X control technology is ULNB.

Step 5 – Select BACT

NO_X BACT for BOIL-2 is determined to be the use of ultra low-NO_X burners and good combustion practices.

Emission Unit	NO_X BACT Determination	NO_X BACT Limit	Averaging Period
BOIL-2 (EQT0001)	Ultra low-NO_X burners and good combustion practices	0.01 lb/MMBtu	Annual average during normal operations

BACT for CO

EQT0001 BOIL-2 Auxiliary Boiler

CO emissions from the boiler are a result of incomplete combustion. Specifically, CO results when there is insufficient residence time at high temperature or incomplete mixing in the combustion zone to complete the final step in the oxidation of carbon from CO to CO_2. Further, control technologies for NO_X emissions, such as low-NO_X burners, may result in increased CO emissions. Additionally, the boiler will be subject to the work practice standards of 40 CFR 63 Subpart DDDDD, which reduce overall CO emissions by promoting proper operation and maintenance of combustion equipment.

Step 1 – Identify All Control Technologies

The following are available CO emission control technologies for BOIL-2:

1. Good Combustion Practices
2. Catalytic Oxidation

Step 2 – Eliminate Technically Infeasible Options

Catalytic oxidation uses a catalyst to oxidize CO to CO_2. The inlet gas stream to the oxidation catalyst bed must be between 600 and 800°F.[20] The exhaust stream from the proposed BOIL-2 will not be in optimal design range temperature for an oxidation catalyst. Therefore, this control technology is determined to be technically infeasible.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only remaining technically feasible control options is good combustion practices.

Step 4 – Evaluate Most Effective Controls

The only remaining technically feasible control options is good combustion practices.

Step 5 – Select BACT

CO BACT for BOIL-2 is determined to be the use of good combustion practices and compliance with 40 CFR 63 Subpart DDDDD.

Emission Unit	CO BACT Determination	CO BACT Limit	Averaging Period
BOIL-2 (EQT0001)	Good combustion practices and compliance with 40 CFR 63 Subpart DDDDD	0.05 lb/MMBtu	Annual average during normal operations

BACT for Auxiliary Boiler - VOC

EQT0001	BOIL-2	Auxiliary Boiler

The Boiler emits VOC due to the incomplete oxidation of hydrocarbons present in the gaseous fuels. However, the low molecular weight characteristic of the hydrocarbons in the fuels will promote low levels of VOC emissions from the Boiler. Additionally, the boiler will be subject to the work practice standards of 40 CFR 63 Subpart DDDDD, which reduce overall VOC emissions by promoting proper operation and maintenance of combustion equipment.

Step 1 – Identify All Control Technologies

The following are available VOC emission control technologies for BOIL-2:

[20] USEPA Air Pollution Control Technology Fact Sheet, Catalytic Incinerator. https://www3.epa.gov/ttncatc1/dir1/fcataly.pdf

1. Good Combustion Practices
2. Catalytic Oxidation

Step 2 – Eliminate Technically Infeasible Options

Catalytic oxidation uses a catalyst to oxidize hydrocarbons to CO_2 and water. The inlet gas stream to the oxidation catalyst bed must be between 600 and 800°F.[21] The exhaust stream from the proposed BOIL-2 will not be in optimal design range temperature for an oxidation catalyst. Therefore, this control technology is determined to be technically infeasible.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only remaining technically feasible control options is good combustion practices.

Step 4 – Evaluate Most Effective Controls

The only remaining technically feasible control options is good combustion practices.

Step 5 – Select BACT

VOC BACT for BOIL-2 is determined to be the use of good combustion practices and compliance with 40 CFR 63 Subpart DDDDD.

Emission Unit	VOC BACT Determination	VOC BACT Limit	Averaging Period
BOIL-2 (EQT0001)	Good combustion practices and compliance with 40 CFR 63 Subpart DDDDD	0.0054 lb/MMBtu	Annual average during normal operations

BACT for CO_2e

EQT0001	BOIL-2	Auxiliary Boiler

GHG emissions from BOIL-2 will originate from the combustion of natural gas. BOIL-2 will be utilized during startup of the CCGT-2 unit. The boiler is subject to the GHG reporting requirements of 40 CFR 98 Subpart C; however, the boiler is not subject to any state or federal GHG emission standards. Additionally, the boiler will be subject to the work practice standards of 40 CFR 63 Subpart DDDDD, which reduce overall GHG emissions by promoting proper operation and maintenance of combustion equipment.

[21] USEPA Air Pollution Control Technology Fact Sheet, Catalytic Incinerator. https://www3.epa.gov/ttncatc1/dir1/fcataly.pdf

Step 1 – Identify All Control Technologies

The following are available CO_2e emission control technologies for BOIL-2:

1. CCS
2. Energy Efficient Measures (including selection of an efficient boiler, use of gaseous fuels, and good combustion practices)

Step 2 – Eliminate Technically Infeasible Options

CCS is not feasible solely for small combustion units such as BOIL-2, which is an 80 MMBtu/hr unit. CCS is eliminated as a control technology for BOIL-2. Therefore, this option is not evaluated in the subsequent analysis. Additionally, the RBLC database does not include CCS as a control option for similarly sized boilers.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only remaining available GHG emission control technology for the Boiler is selection of an efficient boiler, use of gaseous fuels, and good combustion practices.

Step 4 – Evaluate Most Effective Controls

The only remaining available GHG emission control technology for the Boiler is selection of an efficient boiler, use of gaseous fuels, and good combustion practices.

Step 5 – Select BACT

CO_2e BACT for the BOIL-2 is determined to be an efficient boiler; use of gaseous fuels, including pipeline quality natural gas or up to 50% natural gas and hydrogen; good combustion practices; and compliance with 40 CFR 63 Subpart DDDDD.

Emission Unit	CO_2e BACT Determination	CO_2e BACT Limit	Averaging Period
BOIL-2 (EQT0001)	Energy efficient design, use of gaseous fuel, good combustion practices, and compliance with 40 CFR 63 Subpart DDDDD	117 lb/MMBtu	annual average during normal operations

BACT Review for Emergency Diesel Generator and Emergency Diesel Fire Water Pump – PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, & CO_2e

The Emergency Diesel Generator (EPN EGEN-2) will have a rating of 2,937 hp, and the Emergency Diesel Fire Water Pump (EPN FWP-2) will have a rating of 355 hp. Both engines

will be compression ignition (diesel). The engines are subject to BACT for NO_X, CO, PM_{10}, $PM_{2.5}$, VOC, and CO_2e.

The use of these engines is limited to emergency situations, except for up to 100 hours per year, including maintenance testing. Because engine operation is intermittent and operating hours are limited, emissions from the engines are minimal, making most applications of add-on control devices technically and/or economically infeasible. Furthermore, the engines are subject to the emission standards of 40 CFR 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

The NO_X, CO, PM_{10}, $PM_{2.5}$, VOC, and CO_2e control technology options identified during a search of EPA's RBLC database for similar engines are proper operation, good combustion practices, and compliance with NSPS Subpart IIII for diesel-fired engines.

BACT for NO_X, CO, PM_{10}, $PM_{2.5}$, VOC, and CO_2e emissions from the engines is determined to be compliance with NSPS Subpart IIII. Note that Subpart IIII incorporates specific combustion (operational) and maintenance practices.

Emission Unit	Pollutant	BACT Determination	BACT Limit
EGEN-2 (EQT0003)	PM_{10}	Good combustion practices and compliance with 40 CFR 60 Subpart IIII	0.15 g/BHP-hr
	$PM_{2.5}$		0.15 g/BHP-hr
	NO_X		4.8 g/BHP-hr (NO_X + NMHC)
	CO		2.6 g/BHP-hr
	VOC		4.8 g/BHP-hr (NO_X + NMHC)
	CO_2e		74.21 kg/MMBtu
FWP-2 (EQT0004)	PM_{10}	Good combustion practices and compliance with 40 CFR 60 Subpart IIII	0.15 g/BHP-hr
	$PM_{2.5}$		0.15 g/BHP-hr
	NO_X		3.0 g/BHP-hr (NO_X + NMHC)
	CO		2.6 g/BHP-hr
	VOC		3.0 g/BHP-hr (NO_X + NMHC)
	CO_2e		74.21 kg/MMBtu

BACT Review for Atmospheric Drain Tank - VOC

Unit 2 will include an Atmospheric Drains Tank (EPN TK-6), which will have a capacity of 5,475 gallons and a throughput of approximately 100,000 gallons per year. Potential emissions result from breathing and working losses associated with the tank.

This tank will not be subject to any federal or state regulations requiring emissions controls.

Tank emissions have been estimated using AP-42, Chapter 7.1 emission factors. With

Tank emissions have been estimated using AP-42, Chapter 7.1 emission factors. With estimated emissions of 0.05 tpy VOC, control technologies for the tank, such as a floating roof or vapor collection system with a control device, are not feasible or practical, as they offer no appreciable decrease in emissions and would not be cost effective.

VOC BACT for Atmospheric Drains Tank is determined to be installation and use of a submerged fill pipe.

Emission Unit	VOC BACT Determination	VOC BACT Limit	Averaging Period
TK-6 (EQT0005)	Equip with a submerged fill pipe	N/A	N/A

BACT Review for Fugitive Components – CO_2e

FUG0001	FUG-2	Unit 2 Fugitive Emissions

Unit 2 fugitive components have the potential to emit methane, which is a GHG, and a very small amount of ammonia. Fugitive components that contain or contact methane or ammonia are not subject to any Leak Detection and Repair (LDAR) regulations.

Step 1 – Identify All Control Technologies

The following are available CO_2e emission control technologies for the fugitive emissions:

1. Proper Piping Design and Installation
2. LDAR Program

Proper Piping Design and Installation
Proper piping design and initial installation can help in ensuring a leak-tight system that reduces emissions due to leaks. Proper design and installation practices can include:

- Verify proper bracing;
- Verify all joints are tight;
- Confirmation that all pipes are properly assembled;
- Design piping for adequate/desired pressure;
- Verify proper seal design/selection;
- Verify proper installation of valve packing or O rings; and
- Inspect installation of the disk gaskets on pressure relief devices.[22]

LDAR Program
LDAR programs are used to identify piping components leaking material at a level warranting component repair (or replacement), and the effectiveness of these programs has been well

[22] https://www.epa.gov/sites/default/files/2014-02/documents/ldarguide.pdf

established throughout many different industries. The primary features of an LDAR program are leak monitoring frequency, leak detection level, and timely leak repair. A piping component may be checked for leakage by visual, audible, olfactory, or instrument techniques. For example, visual inspections may be used to identify leaks of heavy liquid material from connectors, valves, and pumps. Alternatively, a portable hydrocarbon detection instrument is typically used to identify (and measure) leaks of gases and light liquid materials from piping components. After a leak is detected, it must typically be repaired within a specific time period, followed by a subsequent leak inspection to ensure the leaking component was properly repaired.

Step 2 – Eliminate Technically Infeasible Options

Proper piping design and installation and LDAR practices can be applied to GHG (methane) or ammonia fugitive components. Many LDAR programs are required per federal regulations, such as NSPS and NESHAP. Unit 2 will not be subject to any state or federal regulations that require an LDAR program; however, it is still a technically feasible and viable option. Therefore, both control technologies are technically feasible.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The technically feasible control options are ranked below, according to their control effectiveness:

1. LDAR Program
2. Proper Piping Design and Installation

Step 4 – Evaluate Most Effective Controls

Unit 2 will not be subject to any state or federal LDAR programs. Due to the fact that the predicted annual fugitive emissions of methane are low, the use of an LDAR program is considered economically infeasible. Based on comments submitted by the American Petroleum Institute per Docket ID No. EPA-HQ-OAR-2010-0505,[23] an economic analysis predicts a cost of $22,261 per ton of methane removed. LDAR program costs were not considered for ammonia emissions, as potential emissions of this compound are 0.14 tons per year.

Step 5 – Select BACT

CO_2e BACT for FUG-2 is determined to be proper piping design and installation.

[23] Comments from American Petroleum Institute to the USEPA dated December 4, 2015, https://www.api.org/-/media/files/news/letters-comments/2015/15-december/api-comments-on-nsps-12042015.pdf

Emission Unit	CO_2e BACT Determination	CO_2e BACT Limit	Averaging Period
FUG-2 (FUG0001)	Proper piping design and installation	N/A	N/A

BACT Review for Circuit Breakers – CO_2e

EQT0006 CB-2 Circuit Breakers

Unit 2 will include the installation of four (4) Circuit Breakers (EPN CB-2, EQT0006) that will be insulated with sulfur hexafluoride (SF_6). The circuit breakers have the potential for GHG emissions due to a potential leak. The RBLC database was searched for similar source types. Based on the search, BACT for circuit breakers that use SF_6 is a certified leak rate of 0.5% or less on a calendar year average. Additional BACT applications, per the RBLC, include a leak detection system, alarms, and enclosed pressure design.

CO_2e BACT for CB-2 is an enclosed design with low pressure detection system, including an alarm and automatic lockout, to limit the SF_6 leak rate to 0.5% per year, as well as compliance with American National Standards Institute (ANSI) standards and emission limits demonstrated using methodology per 40 CFR 98 Subpart DD.

Emission Unit	CO_2e BACT Determination	CO_2e BACT Limit	Averaging Period
CB-2 (EQT0006)	Enclosed pressure design with a low-pressure detection system with an alarm to limit the SF_6 leak rate to 0.05% per year. Compliance with ANSI standards and with emission limits demonstrated using the methodology in 40 CFR 98 Subpart DD	85 tpy	12-month rolling average

A summary of BACT costs for technologies eliminated for economic reasons is presented in Table II.

B. ANALYSIS OF EXISTING AIR QUALITY

Prevention of Significant Deterioration regulations require an analysis of existing air quality for those pollutants to be emitted in significant amounts from a proposed facility. PM_{10}, $PM_{2.5}$, NO_X, and CO are pollutants of concern in this case.

AERMOD modeling of $PM_{2.5}$, PM_{10}, NO_X, and CO emissions from the proposed project indicates that the maximum offsite ground level concentrations of these pollutants will be below their respective PSD significance levels and preconstruction monitoring levels.

Therefore, pre-construction monitoring, refined NAAQS modeling, and increment consumption analyses were not required.

C. NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS) ANALYSIS

AERMOD modeling analyses indicated that concentrations of $PM_{2.5}$, PM_{10}, NO_2, and CO will be below their respective PSD ambient significance levels; therefore, refined NAAQS modeling was not required for these pollutants. A summary of the air quality analyses is presented in Table III.

D. PSD INCREMENT ANALYSIS

A PSD increment is the maximum allowable increase in a concentration above a baseline concentration for a pollutant. The baseline concentration is defined for each pollutant (and appropriate averaging time) and is, in general, the ambient concentration that exists when the first complete PSD permit application affecting the area was submitted (i.e., the minor source baseline date).

Because AERMOD modeling analyses indicated that concentrations of $PM_{2.5}$, PM_{10}, NO_x, and CO will be below their respective PSD ambient significance levels, PSD increment modeling was not required. A summary of the air quality analyses is also presented in Table III.

E. SOURCE RELATED GROWTH IMPACTS

Operation of this facility is not expected to have any significant effect on residential growth or industrial/commercial development in the area of the facility. No significant net change in employment, population, or housing will be associated with the project. Approximately 27 new permanent jobs will be created. Employment during construction will increase temporarily, with a range of 350 to 400 jobs.

F. SOILS, VEGETATION, AND VISIBILITY IMPACTS

There will be no significant impact on area soils, vegetation, or visibility.

G. CLASS I AREA IMPACTS

Louisiana's Breton Wildlife Refuge, the nearest Class I area, is over 100 kilometers from the site, precluding any significant impact.

H. TOXIC EMISSIONS IMPACT

The selection of control technology based on the BACT analysis included consideration of control of toxic emissions.

V. CONCLUSION

The Air Permits Division has made a preliminary determination to approve the construction and operation of the Camellia Power Unit 2 in Plaquemine, Iberville Parish, Louisiana, subject to the attached specific and general conditions. In the event of a discrepancy in the provisions found in the application and those in this Preliminary Determination Summary, the Preliminary Determination Summary shall prevail.

SPECIFIC CONDITIONS

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine Iberville Parish, Louisiana
PSD-LA-863

1. Comply with the Louisiana General Conditions as set forth in LAC 33:III.537.

2. The permittee is authorized to operate in conformity with the specifications submitted to the Louisiana Department of Environmental Quality (LDEQ) as analyzed in LDEQ's document entitled "Preliminary Determination Summary" dated March 12, 2025, and subject to the following emissions limitations and other specified conditions. Specifications submitted are contained in the application and Emission Inventory Questionnaire dated December 17, 2024, and additional information received on July 2, 2025.

3. The facility shall ensure compliance with the terms of this permit as follows for the Combined Cycle Gas Turbine 2 with Duct Burners and HRSG (EQT0002):

    - $PM_{10}/PM_{2.5}$: Shall conduct performance/emission tests according to 40 CFR 51, Appendix M, Method 201A – Determination of PM_{10} and $PM_{2.5}$ Emissions from Stationary Sources; and Method 202-Dry Impinger Method for Determining Condensable Particulate Emissions from Stationary Sources. Method 5 of 40 CFR 60 Appendix A may be substituted for Method 201A if all particulate matter is assumed to be $PM_{2.5}$;
    - NO_X: Shall use a CEMS required by NSPS Subpart KKKK (not applicable during startup and shutdown operations) and conduct an initial performance test required by NSPS Subpart KKKK;
    - CO: Shall install a CEMs to monitor CO; and
    - VOC: Shall conduct performance/emission tests according to 40 CFR 60, Appendix A: Method 25A-Determination of Gaseous Organic Concentration using a Flame Ionization Analyzer.

4. For the turbine (EPN CCGT-2, EQT0002), good combustion practices shall be demonstrated by continuously monitoring the air-to-fuel ratio and maintaining the ratio within the range recommended by the manufacturer.

5. For the control of VOC and CO emissions, the turbine (EPN CCGT-2, EQT0002) shall be equipped with catalytic oxidation.

6. The turbine (EPN CCGT-2, EQT0002) shall be equipped with Selective Catalytic Reduction (SCR) and Dry Low NO_X Combustors for control of NO_x emissions during normaloperations.

7. The turbine (EPN CCGT-2, EQT0002) shall fire only gaseous fuel (pipeline quality natural gas or a blend of up to 50% H_2 and natural gas).

8. The facility shall comply with 40 CFR Part 60 Subpart IIII (Tier 2 non-road engines), use good combustion practices, and use ultra-low sulfur diesel fuel for control of $PM_{10}/PM_{2.5}$, NO_x, VOC,

CO_2e, and CO emissions from the Emergency Diesel Generator (EPN EGEN-2, EQT0003) and Emergency Firewater Pump (EPN FWP-2, EQT0004). Good combustion practices entail operating and maintaining the engines in accordance with the manufacturer's instructions and/or recommendations. Camellia Power shall keep a maintenance plan and records of maintenance conducted on each engine.

9. The Auxiliary Boiler (EPN BOIL-2, EQT0001) shall be equipped with ultra-low NO_X burners to control emissions to 0.01 lb NO_x/MMBTU on an annual average basis during normal operations.

10. For the Auxiliary Boiler (EPN BOIL-2, EQT0001), good combustion practices shall be demonstrated by complying with 40 CFR 63 Subpart DDDDD and by continuously monitoring the air-to-fuel ratio and maintaining the ratio within the range recommended by the manufacturer.

11. The Atmospheric Drains Tank (EPN TK-6, EQT0005) shall be equipped with a submerged fill pipe to control VOC emissions.

12. The Circuit Breakers (EPN CB-2, EQT0006) shall be of an enclosed pressure design and be equipped with a low pressure detection system with an alarm to limit the SF_6 leak rate to 0.5 % per year and shall be designed to meet the current American National Standards Institute (ANSI) standards for high voltage circuit breakers. Compliance with emission limits shall be demonstrated using the methodology in 40 CFR 98 Subpart DD.

13. For the Combined Cycle Gas Turbine -Start-up and Shutdown (EPN CCGT-2-SUSD, SCN0002), good combustion practices shall be used to control CO_2e, $PM_{10}/PM_{2.5}$, NO_x, CO, H_2SO_4, and VOC emissions. Good combustion practices entail following the startup and shutdown procedures recommended by the turbine manufacturer. Camellia Power shall 1.) develop a written startup and shutdown plan that describes, in detail, procedures for operating and maintaining the source during periods of startup and shutdown; and 2.) keep records of any actions taken during a startup or shutdown that are not consistent with the procedures specified in the plan and which resulted in an exceedance of emission limitations.

TABLE I: MAXIMUM ALLOWABLE OPERATING AND EMISSION RATES

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine, Iberville Parish, Louisiana
PSD-LA-863

ID No.	Description		Units	PM_{10}	$PM_{2.5}$	NO_X	CO	VOC	H_2SO_4	CO_2e
EQT0002	CCGT-2	Combined Cycle Gas Turbine with Duct Burner and HRSG	lb/hr	29.35	29.35	47.07	73.94	30.22	6.20	-
			TPY	128.55	128.55	171.33	224.92	97.59	25.40	2,658,075
			lb/MMBtu	0.008	0.008	-	-	-	-	-
			ppmvd @ 15% O_2	-	-	2.0	2.0	No duct firing: 1.0 With duct firing: 2.0	-	-
			grains/dscf	-	-	-	-	-	0.00623	-
			lb/MWh-gross	-	-	-	-	-	-	800
SCN0001	CCGT-COMM-2	Combined Cycle Gas Turbine 2 – Startup and Shutdown	TPY	3.90	3.90	85.70	1469.97	305.41	-	72595
SCN0002	CCGT-2-SUSD	Combined Cycle Gas Turbine – Startup and Shutdown	lb/hr	27.43	27.43	385.71	2800.00	950.00	2.34	-
EQT0001	BOIL-2	Auxiliary Boiler	lb/hr	0.59	0.59	0.80	4.00	0.43	-	-
			TPY	2.60	2.60	3.50	17.52	1.88	-	41,031
			lb/MMBtu	0.0074	0.0074	0.01	0.05	0.0054	-	117
EQT0003	EGEN-2	Emergency Diesel Generator	lb/hr	0.97	0.97	30.93	16.91	30.93	-	-
			TPY	0.05	0.05	1.55	0.85	1.55	-	168
			g/BHP-hr	0.15	0.15	4.8*	2.6	4.8*	-	-

TABLE I: MAXIMUM ALLOWABLE OPERATING AND EMISSION RATES

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine, Iberville Parish, Louisiana
PSD-LA-863

ID No.	Description		Units	PM_{10}	$PM_{2.5}$	NO_X	CO	VOC	H_2SO_4	CO_2e
EQT0004	FWP-2	Emergency Diesel Fire Water Pump	lb/hr	0.12	0.12	2.34	2.04	2.34	-	-
			TPY	0.01	0.01	0.12	0.10	0.12	-	20
			g/BHP-hr	0.15	0.15	3.0*	2.6	3.0*	-	-
EQT0005	TK-6	Atmospheric Drain Tank	TPY	-	-	-	-	0.05	-	-
EQT0006	CB-2	Circuit Breakers	TPY	-	-	-	-	-	-	85

*Denotes a limitation in terms of non-methane hydrocarbons plus NO_X as a surrogate for NO_X and VOC emission limits.

TABLE II: BACT COST SUMMARY

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine, Iberville Parish, Louisiana
PSD-LA-863

Control Alternatives		Availability/ Feasibility	Negative Impacts (a)	Control Efficiency	Emissions Reduction (TPY)	Capital Cost ($)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Notes
Combined Cycle Gas Turbine 2 with Duct Burners and HRSG (EQT0002)									
$PM_{10}/PM_{2.5}$	Use of gaseous fuel (pipeline quality natural gas or a blend of up to 50% H_2 and natural gas) and good combustion practices	Yes	n/a	0.008 lb/MMBtu	n/a	n/a	n/a	n/a	BACT
	Good Combustion Practices	Yes	n/a	n/a	n/a	n/a	n/a	n/a	BACT
NO_X	Selective Catalytic Reduction (SCR) with Dry Low NOx (DLN) Combustors	Yes	n/a	2 ppmvd at 15% O_2	n/a	n/a	n/a	n/a	BACT
	Good Combustion Practices	Yes	n/a	n/a	n/a	n/a	n/a	n/a	BACT
CO	Catalytic Oxidation	Yes	n/a	2.0 ppmvd at 15% O_2	n/a	n/a	n/a	n/a	BACT
	Good Combustion Practices	Yes	n/a	n/a	n/a	n/a	n/a	n/a	BACT
VOC	Catalytic Oxidation	Yes	n/a	1.0 and 2.0 ppmvd at 15% O_2 (without and with duct firing)	n/a	n/a	n/a	n/a	BACT
	Good Combustion Practices	Yes	n/a	n/a	n/a	n/a	n/a	n/a	BACT
Sulfuric Acid Mist	Good Combustion Practices	Yes	n/a	n/a	n/a	n/a	n/a	n/a	BACT
	Use of low sulfur fuel such as natural gas	Yes	n/a	0.00623 grains of sulfur/dscf	n/a	n/a	n/a	n/a	BACT
CO_2e (CO_2)	Use of gaseous fuel (pipeline-quality natural gas), thermally efficient turbine, and good combustion practices	Yes	n/a	800 lbs CO_2e/MW-hr	n/a	n/a	n/a	n/a	BACT

TABLE II: BACT COST SUMMARY

Camellia Power Unit 2
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Plaquemine, Iberville Parish, Louisiana
PSD-LA-863

Control Alternatives		Availability/ Feasibility	Negative Impacts (a)	Control Efficiency	Emissions Reduction (TPY)	Capital Cost ($)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Notes
Combined Cycle Gas Turbine 2 -Startup and Shutdown (SCN0002)									
NO_X, CO, H_2SO_4, CO_2e, VOC, $PM_{10}/PM_{2.5}$	Good Combustion Practices	Yes	n/a	n/a	n/a	n/a	n/a	n/a	BACT
Auxiliary Boiler (EQT0001)									
$PM_{10}/PM_{2.5}$	Gaseous fuels for improved combustion efficiency	Yes	n/a	0.0074 lb/MMBtu	n/a	n/a	n/a	n/a	BACT
	Good Combustion Practices	Yes	n/a	n/a	n/a	n/a	n/a	n/a	BACT
NOx	Ultra-Low NO_x Burners	Yes	n/a	0.01 lb/MMBtu	n/a	n/a	n/a	n/a	BACT
	Good Combustion Practices	Yes	n/a	n/a	n/a	n/a	n/a	n/a	BACT
CO and VOC	Good Combustion Practices; compliance with 40 CFR 63 Subpart DDDDD	Yes	n/a	0.05 lb/CO MMBtu; 0.0054 lb VOC/MMBtu	n/a	n/a	n/a	n/a	BACT
CO_2e	Good Combustion Practices; compliance with 40 CFR 63 Subpart DDDDD	Yes	n/a	117 lbs CO_2e/ MMBtu	n/a	n/a	n/a	n/a	BACT
Emergency Diesel Generator (EQT0003) and Emergency Diesel Fire Water Pump (EQT0004)									
$PM_{10}/PM_{2.5}$, NO_X, CO, VOC, & CO_2e	40 CFR Part 60 Subpart IIII	Yes	n/a	n/a	n/a	n/a	n/a	n/a	BACT

TABLE II: BACT COST SUMMARY

Camellia Power Unit 2
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Camellia Power LLC
Plaquemine, Iberville Parish, Louisiana
PSD-LA-863

Control Alternatives		Availability/ Feasibility	Negative Impacts (a)	Control Efficiency	Emissions Reduction (TPY)	Capital Cost ($)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Notes
Atmospheric Drain Tank 2 (EQT0005)									
VOC	Submerged fill pipe	Yes	n/a	n/a	n/a	n/a	n/a	n/a	BACT
Circuit Breakers (EQT0006)									
CO_2e	Enclosed pressure design with a low pressure detection system with an alarm to limit the SF6 leak rate to 0.5 % per year. Compliance with American National Standards Institute (ANSI) standards and with emission limits demonstrated using the methodology in 40 CFR 98 Subpart DD.	Yes	n/a	85 tpy CO_2e	n/a	n/a	n/a	n/a	BACT
Fugitives (FUG0001)									
	LDAR Program	Yes	1	-	-	n/a	-	$22,261	Not selected
	Proper piping design and installation	Yes	n/a	104 tpy CO_2e	n/a	n/a	n/a	n/a	BACT

Notes: a) Negative impacts: 1) economic, 2) environmental, 3) energy, 4) safety

TABLE III: AIR QUALITY ANALYSIS SUMMARY

Camellia Power Unit 2
Agency Interest No.: 246887
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Plaquemine, Iberville Parish, Louisiana
PSD-LA-863

Pollutant	Averaging Period	Preliminary Screening Concentration ($\mu g/m^3$)	Level of Significant Impact ($\mu g/m^3$)	Significant Monitoring Concentration ($\mu g/m^3$)	Current Modeled Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Modeled PSD Increment Consumption ($\mu g/m^3$)	Allowable Class II PSD Increment ($\mu g/m^3$)
$PM_{2.5}$	24-hour	0.84*	1.2	4	-	35	-	9
	Annual	0.10	0.13	-	-	9	-	4
PM_{10}	24-hour	0.85	5	10	-	150	-	30
	Annual	0.10	1	-	-	-	-	17
NO_X	1-hour	2.94	7.5	-	-	188	-	-
	Annual	0.38	1	14	-	100	-	25
CO	1-hour	675.16	2000	-	-	40,000	-	-
	8-hour	297.98	500	575	-	10,000	-	-
*Includes $PM_{2.5}$ secondary emissions 0.0063 $\mu g/m^3$ 24 hour $PM_{2.5}$ and 0.0014 $\mu g/m^3$ Annual $PM_{2.5}$.								

TABLE IV: BACT SUMMARY

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine, Iberville Parish, Louisiana
PSD-LA-863

Emission Unit	Pollutant	BACT Determination	BACT Limit
CCGT-2 (EQT0002)	$PM_{2.5}$	Use of gaseous fuel (pipeline quality natural gas or a blend of up to 50% H_2 and natural gas) and good combustion practices	0.008 lb/MMBtu
	PM_{10}		0.008 lb/MMBtu
	NO_X	Dry low-NO_X combustor design, SCR, and good combustion practices	2.0 ppmvd @15% O_2
	CO	Catalytic oxidation and good combustion practices	2.0 ppmvd @15% O_2
	VOC	Catalytic oxidation and good combustion practices	1.0 (no duct firing) and 2.0 (with duct firing) ppmvd @15% O_2
	CO_2e	Use of gaseous fuel (pipeline quality natural gas or a blend of up to 50% H_2 and natural gas), thermally efficient turbines, and good combustion practices	800 lb/MWh-gross
	H_2SO_4		0.00623 grains/dscf
CCGT-2-SUSD (SCN0002)	$PM_{2.5}$	Use of gaseous fuel (pipeline quality natural gas or a blend of up to 50% H_2 and natural gas) and good combustion practices	0.008 lb/MMBtu
	PM_{10}		0.008 lb/MMBtu
	NO_X	Good combustion practices	-
	CO	Good combustion practices	-
	VOC	Good combustion practices	-
	CO_2e	Use of gaseous fuel (pipeline quality natural gas or a blend of up to 50% H_2 and natural gas), thermally efficient turbines, and good combustion practices	800 lb/MWh-gross
	H_2SO_4		0.00623 grains/dscf
BOIL-2 (EQT0001)	$PM_{2.5}$	Use of gaseous fuel (pipeline quality natural gas or a blend of up to 50% H_2 and natural gas) and good combustion practices	0.0074 lb/MMBtu
	PM_{10}		0.0074 lb/MMBtu
	NO_X	Ultra Low- NO_X burners and good combustion practices	0.01 lb/MMBtu
	CO	Good combustion practices and compliance with 40 CFR 63 Subpart DDDDD	0.05 lb/MMBtu

TABLE IV: BACT SUMMARY

Camellia Power Unit 2
Agency Interest No.: 246887
Camellia Power LLC
Plaquemine, Iberville Parish, Louisiana
PSD-LA-863

Emission Unit	Pollutant	BACT Determination	BACT Limit
BOIL-2 (EQT0001)	VOC		0.054 lb/MMBtu
	CO_2e		117 lb/MMBtu
EGEN-2 (EQT0003)	PM_{10}	Good combustion practices and compliance with 40 CFR 60 Subpart IIII	0.15 g/BHP-hr
	$PM_{2.5}$		0.15 g/BHP-hr
	NO_X		4.8 g/BNP-hr (NO_X + NMHC)
	CO		2.6 g/BHP-hr
	VOC		4.8 g/BNP-hr (NO_X + NMHC)
	CO_2e		74.21 kg/MMBtu
FWP-2 (EQT0004)	PM_{10}	Good combustion practices and compliance with 40 CFR 60 Subpart IIII	0.15 g/BHP-hr
	$PM_{2.5}$		0.15 g/BHP-hr
	NO_X		3.0 g/BNP-hr (NO_X + NMHC)
	CO		2.6 g/BHP-hr
	VOC		3.0 g/BNP-hr (NO_X + NMHC)
	CO_2e		74.21 kg/MMBtu
TK-6 (EQT0005)	VOC	Equip with a submerged fill pipe	-

TABLE IV: BACT SUMMARY

Camellia Power Unit 2
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Plaquemine, Iberville Parish, Louisiana
PSD-LA-863

Emission Unit	Pollutant	BACT Determination	BACT Limit
FUG-2 (FUG0001)	CO_2e	Proper piping design and installation	-
CB-2 (EQT0006)	CO_2e	Enclosed pressure design with a low-pressure detection system with an alarm to limit the SF_6 leak rate to 0.05% per year. Compliance with ANSI standards and with emission limits demonstrated using the methodology in 40 CFR 98 Subpart DD.	85 tpy