Desert Sun Power Plant

Construction and Title V Air Quality Operating Permit Application

New Natural Gas-Fired Combined Cycle Combustion Turbine Electric Generating Facility.

May 2026

Prepared for:

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Chapter 1. Executive Summary.

Arizona Public Service (APS) is proposing to construct and operate a new power plant in Gila Bend, Maricopa County called the Desert Sun Power Plant. This power plant will consist of two (2) GE Vernova Model 7HA.02 natural gas-fired combustion turbine (CT) electric generating units. These units will be constructed as combined cycle units in a 1x1 configuration in which each CT will have a separate heat recovery steam generator (HRSG) and a separate steam turbine/electric generator set. Each combined cycle unit will have a total nominal electric generating capacity of 530 MW unfired and 630 MW with supplemental duct firing. These CTs will be equipped with state-of-the-art air quality control systems including dry-low NO_x combustors and selective catalytic reduction (SCR) for nitrogen oxides (NO_x) control, and oxidation catalysts for carbon monoxide (CO) volatile organic compound (VOC), and organic hazardous air pollutant (HAP) control. This facility will also include a natural gas-fired auxiliary boiler, a natural gas-fired natural gas conditioning heater, two (2) mechanical draft cooling towers, an emergency fire pump, natural gas piping systems, and sulfur hexafluoride (SF_6) insulated high voltage circuit breakers.

This facility will be located in an area that is classified as attainment or unclassified for all criteria air pollutants. New stationary sources with potential emissions in excess of the major source threshold levels in the federal Prevention of Significant Deterioration of Air Quality (PSD) program are subject to PSD review. The following table is a summary of the potential emissions based on the proposed limits in this application. From this table, the Project will be a major stationary source for carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM), PM_{10}, $PM_{2.5}$, volatile organic compounds (VOC), and greenhouse gas (GHG) emissions. Therefore, this Project is subject to review under the PSD program for these pollutants.

Potential emissions for the Desert Sun Power Plant and PSD applicability, tons per year.

Pollutant		Potential to Emit	PSD Significant Rate	OVER?
Carbon Monoxide	CO	329.7	100	**YES**
Nitrogen Oxides	NO_x	326.6	40	**YES**
Particulate Matter	PM	160.4	25	**YES**
Particulate Matter	PM_{10}	159.8	15	**YES**
Particulate Matter	$PM_{2.5}$	159.6	10	**YES**
Sulfur Dioxide	SO_2	21.0	40	**NO**
Volatile Organic Compounds	VOC	106.0	40	**YES**
Sulfuric Acid Mist	H_2SO_4	6.3	7	**NO**
Fluorides (F)	F	0.016	3	**NO**
Lead	Pb	0.018	0.6	**NO**
Carbon Dioxide	CO_2	4,097,097	n/a	**n/a**
Greenhouse Gases	CO_2e	4,103,514	75,000	**YES**

One of the most significant requirements under the PSD program is to apply the Best Available Control Technology or BACT for each pollutant which exceeds the significant levels. This application includes a detailed control technology review or BACT analysis for each emissions unit which will have potential emissions of CO, NO_x, PM, PM_{10}, $PM_{2.5}$, VOC, or GHG emissions. As proposed in this application, each emissions unit will utilize state-of-the-art air quality control systems to control emissions from this new power plant.

This application also includes a detailed air quality dispersion modeling analysis and additional impacts analyses as required under the PSD program. The air quality dispersion modeling analysis demonstrates that the proposed Desert Sun Power Plant will meet all applicable air quality standards for carbon monoxide (CO), nitrogen dioxide (NO_2), PM_{10}, $PM_{2.5}$, sulfur dioxide (SO_2), and lead (Pb). The additional impact analyses demonstrate that the new power plant will have minor impacts on soils, vegetation, and visibility in the area, and will also have minor impacts to general commercial, residential, and industrial growth associated with the proposed project.

Chapter 2. Project Description.

Arizona Public Service (APS) is proposing to construct and operate a new natural gas-fired electric generating facility which will be called the Desert Sun Generating Station in Gila Bend, Maricopa County. This new facility will consist of two natural gas-fired, combined cycle combustion turbine (CT) electric generating units. Each combined cycle unit will have a nominal electric generating capacity of 532 MW unfired and 631 MW with supplemental duct firing.

2.1 Project Site.

The Desert Sun Generating Station will be located near the intersection of Painted Rock Road and West Powerline Road in Gila Bend, Arizona. Figure 2-1 shows the general location of the proposed power plant in the State of Arizona and in Maricopa County. Figure 2-1 also shows the current CO, PM_{10}, and ozone (O_3) nonattainment areas. From Figure 2-1, this facility will be located in an area that is in attainment or unclassified for all criteria air pollutants. Figure 2-2 is an aerial image of the project site showing the proposed location of the new power plant and the nearby Solana Solar Generating Station. Figure 2-3 shows the general layout of the proposed combined cycle power blocks on the project site. Figure 2-4 shows more detail of one of the combined cycle power blocks.

2.2 Overview of the Plant Design.

This power plant will utilize two (2) GE Vernova Model 7HA.02 natural gas-fired CT electric generating units as the prime movers. These CTs, designated as CT1 and CT2, will be constructed as combined cycle (CC) units in a 1 x 1 configuration, meaning that each CT will have a separate heat recovery steam generator (HRSG) and a separate steam turbine/electric generator set. Each combined cycle unit will have a total nominal electric generating capacity of approximately 532 MW unfired and 631 MW with HRSG duct firing. Each CT will be equipped with state-of-the-art air quality control systems including dry-low NO_x combustors and selective catalytic reduction (SCR) for nitrogen oxides (NO_x) control and oxidation catalysts for carbon monoxide (CO) and volatile organic compound (VOC) control.

This facility will also include other balance of plant equipment, including:

1. One (1) natural gas-fired auxiliary boiler rated at 90 mmBtu/hr;
2. One (1) natural gas-fired natural gas conditioning or dew point heater rated at 45 mmBtu/hr;
3. Two (2) mechanical draft cooling towers;
4. One (1) diesel engine driven fire pump;
5. Sulfur hexafluoride (SF_6) insulated electric circuit breakers; and
6. Natural gas piping systems.

FIGURE 2-1. Location of the new Desert Sun Power Plant in Arizona and Maricopa County.

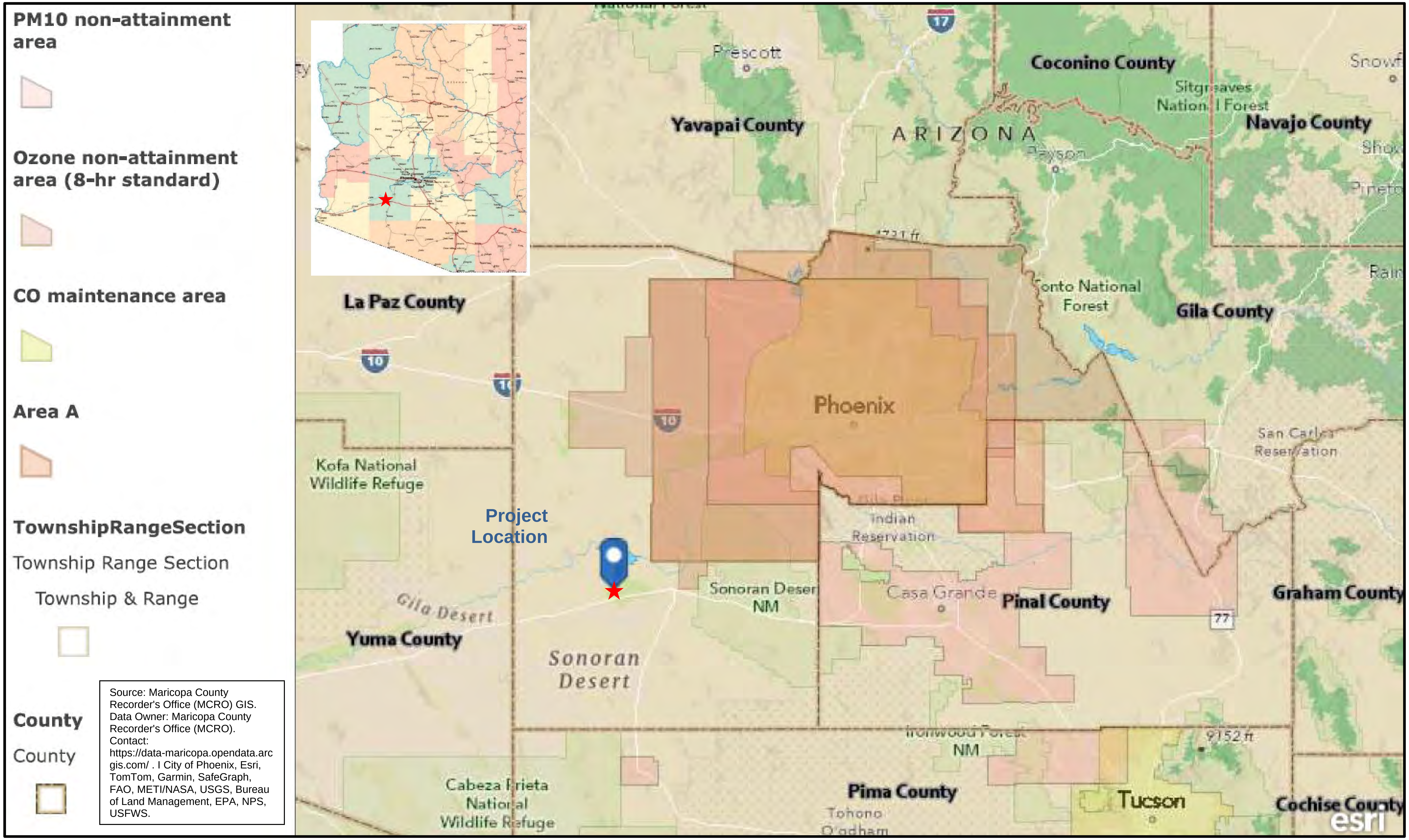
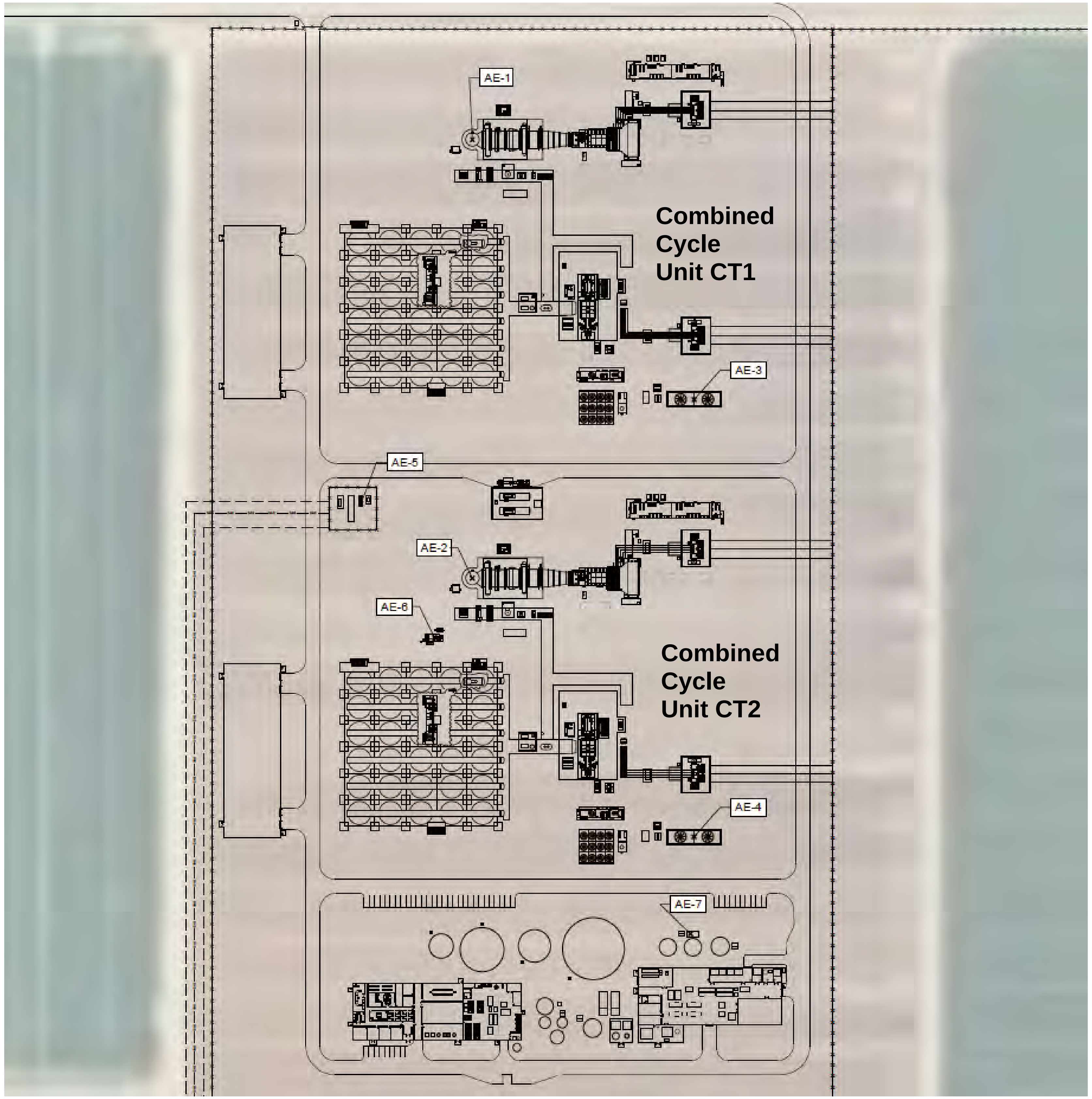


FIGURE 2-2. Aerial image of the location for the Desert Sun Power Plant.

FIGURE 2-3. General arrangement drawing showing the layout of the CTs and other buildings and equipment on the project site.

FIGURE 2-4. General arrangement drawing showing the layout of one of the combined cycle power blocks.



AIR EMISSION (AE) SOURCES	
MARK	DESCRIPTION
AE-1	CC HRSG STACK UNIT 1
AE-2	CC HRSG STACK UNIT 2
AE-3	WET COOLING TOWER UNIT 1
AE-4	WET COOLING TOWER UNIT 2
AE-5	FUEL GAS HEATER 1
AE-6	CCGT AUXILIARY BOILER
AE-7	DIESEL FIRE PUMP

DESERT SUN POWER PLANT
GENERAL ARRANGEMENT
SITE PLAN 2 COMBINED CYCLES
AIR EMISSION SOURCES

FILENAME 10436575-0GA-C1013
SCALE 1"=150'
SHEET 0GA-C10

2.3 GE Vernova Model 7HA.02 Combustion Turbines.

The GE Model 7HA.02 are heavy-duty, natural gas-fired H-class combustion turbine (CT that utilize advanced technology to provide flexible, efficient electric power generation. A CT is an internal combustion engine which uses inlet air as a working fluid to produce mechanical power. This CT technology is comprised of an air inlet system, a multistage axial compressor, a combustion section, and a power turbine section. During operation, ambient air is drawn into the compressor section. The compressed air is heated by the combustion of natural gas in the combustion section. The combustion gases then expand through the power turbine section of the CT. This expansion rotates the shaft of the turbine and the coupled electric generator producing electric power which is then supplied to the electric grid.

The general specifications for each CT are summarized in Table 2-1. Note that the specifications in Table 2-1 are for new CTs which have not undergone any performance degradation due to normal operation. Figures 2-5 and 2-6 show the GEV 7HA.02 heavy duty class CTs (from GE Vernova).

TABLE 2-1. General Specifications for the GE Model 7HA.02 CTs.

Parameter		Value
General	Manufacturer	GE Vernova
	Model	7HA.02
	Maximum Heat Input, mmBtu/hr (each CT)	3,740
	Maximum Duct Burner Heat Input, mmBtu/hr (each CC unit)	1,010
	Manufacturer's Design Efficiency, Unfired, (based on HHV at 20 ^{o}F)	49%
	Manufacturer's Design Efficiency, Fired, (based on HHV at 20 ^{o}F)	46%
With Duct Firing	Summer Rating, MW (80 ^{o}F)	
	Combustion Turbine	363
	Steam Turbine	273
	TOTAL	636
	Winter Rating, MW (20 ^{o}F)	
	Combustion Turbine	375
	Steam Turbine	266
	TOTAL	641
Without Duct Firing	Summer Rating, MW (80 ^{o}F)	
	Combustion Turbine	363
	Steam Turbine	170
	TOTAL	533
	Winter Rating, MW (20 ^{o}F)	
	Combustion Turbine	375
	Steam Turbine	163
	TOTAL	538

Each CT will be equipped with inlet air filters which remove dust and particulate matter from the inlet air. During hot weather, the filtered air may also be cooled by passing the air through an evaporative cooling system. During cold weather, the filtered air may be heated using a radiative heating system. The filtered and conditioned air is then drawn into the low-pressure compressor section where the air is compressed.

The CTs will be enclosed in a metal acoustic enclosure which also contains auxiliary equipment. Each combustion turbine package may be equipped with the following equipment/components:

- Inlet air filters
- Inlet evaporative cooling system
- Anti-icing system
- Lube oil system
- Duplex shell and tube lube oil coolers for the combustion turbine and generator
- Dry low NO_x (DLN) combustor systems
- Selective Catalytic Reduction (SCR) system
- Oxidation catalyst air quality control system
- Fire detection and protection system
- Hydraulic starting system
- Compressor variable bleed valve vent to prevent compressor surge in off-design operation.

2.3.1 Combined Cycle Operation.

When operated as combined-cycle CTs, each unit will use the mechanical energy generated by the CT to power an electric generator in the same way as a simple cycle CT. In addition, Each CT will be equipped with a heat recovery steam generator (HRSG) which recovers the heat in the exhaust gases to produce steam to power a steam turbine electric generator set. In this way, combined cycle units have two power cycles; the mechanical power cycle of the CT engine itself, and a separate Rankine power cycle of the steam turbine electric generator set. For the Desert Sun Power Plant, the proposed combined cycle units will be in a 1 x 1 arrangement, meaning that each combined cycle “unit” has one CT, one HRSG, and one steam turbine. Figure 2-7 is a schematic diagram of a 1 x 1 combined cycle unit.

Each HRSG will also be equipped with duct burners which allow for supplemental natural gas firing in the HRSG to produce more steam and more electric output for increased peak power electric generation. Each HRSG will also be equipped with oxidation catalyst and selective catalytic reduction (SCR) air quality control systems. The exhaust gases pass through the HRSG, SCR and oxidation catalyst control systems before being emitted to the atmosphere.

Combined cycle CTs have the advantage of improved thermal efficiency and lower air emissions per unit of electric energy output (though not necessarily lower emissions per unit of energy *input*) as compared to simple cycle CTs. However, combined cycle CTs also have several disadvantages as compared to simple cycle CTs. First, combined cycle CTs cannot startup and shutdown as rapidly as simple cycle CTs because rapid changes in temperature in the HRSG can damage the HRSG and steam turbine. And while fast-start combined cycle CTs are available, even these units are only capable of achieving startup within 30 minutes, and only then if the unit is already hot. If the unit is not hot, all combined cycle CTs can require extended time periods to achieve full load. Combined cycle CTs are also unable to respond rapidly to the large swings in generation caused by a sudden drop in generation or from large new loads. The long startup and shutdown times and the limited response times to changes in the demand for electricity make combined cycle CTs well suited to intermediate and baseload electric generation, but poor resources for peaking generating capacity.

2.3.2 Dry Low NO_x (DLN) Combustion Systems.

Each CT will be equipped with state-of-the-art dry low NO_x (DLN) combustion systems. DLN utilizes a lean premixed combustion process in which fuel and air are premixed before entering the CT, allowing for more efficient burning, lower combustion temperatures, and lower CO, NO_x, and VOC emissions. GE Vernova's DLN combustion systems enables these CTs to reduce NO_x emissions while enabling high plant efficiency and extending outage intervals. The DLN 2.6e maintains many of the elements of GE Vernova's DLN 2.6+ combustion system but introduces advanced premixing to the 7HA gas turbine combustor.

2.3.3 Selective Catalytic Reduction (SCR).

Selective Catalytic Reduction (SCR) is a post combustion flue gas treatment technique for the reduction of NO_x emissions which uses an ammonia (NH_3) or urea ($CO(NH_2)_2$) injection system and a catalytic reactor. The injection grid disperses ammonia or urea in the flue gas upstream of the catalyst. At the SCR operating temperature, urea decomposes to ammonia. Ammonia reacts with NO_x in the presence of the catalyst to form nitrogen (N_2) and water (H_2O) according to the following overall reaction equations:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$$

Catalysts are substances which evoke chemical reactions that would otherwise not take place, and act by providing a reaction mechanism that has a lower activation energy than the uncatalyzed mechanism. For SCR, the catalyst is usually a noble metal, a base metal (titanium or vanadium) oxide, or a zeolite-based material. Noble metal catalysts are not typically used in SCR systems because of their very high cost.

To achieve optimum long-term NO_x reductions, SCR systems must be properly designed for each application. In addition to critical temperature considerations, the NH_3 or urea injection rate must be carefully controlled to maintain an NH_3/NO_x molar ratio that effectively reduces NO_x. Excessive ammonia injection will result in NH_3 emissions, called ammonia slip. SCR has the capability to make substantial reductions in NO_x emissions from boilers, CTs, and engines. For these CTs, the use of SCR is expected to reduce NO_x emissions by approximately 90%.

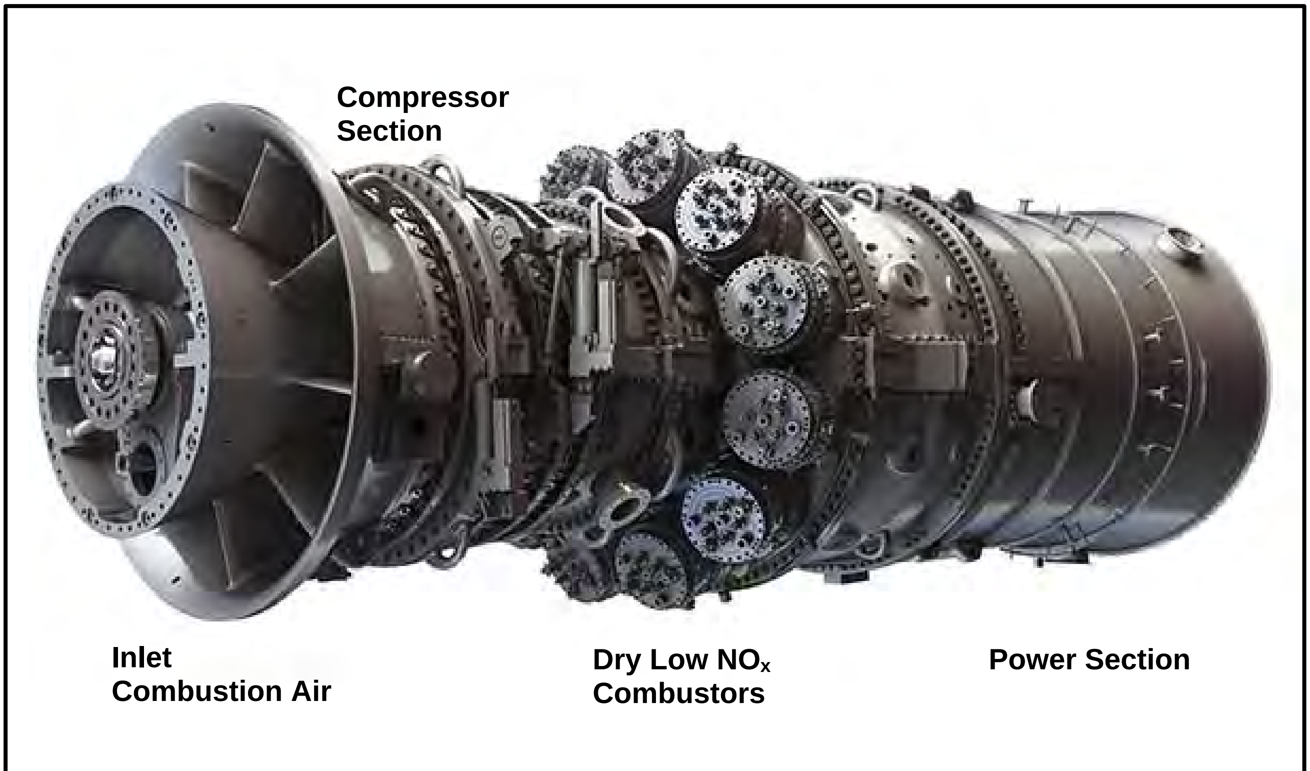
2.3.4 Oxidation Catalyst System.

For natural gas-fired CTs, CO, VOC, and organic HAP emissions may be controlled using oxidation catalysts installed as a post combustion control system. A typical oxidation catalyst is a rhodium or platinum (noble metal) catalyst on an alumina support material. The catalyst is typically installed in a reactor with flue gas inlet and outlet distribution plates. CO and VOC react with oxygen (O_2) in the presence of the catalyst to form carbon dioxide (CO_2) and water (H_2O) according to the following general equations:

$$2CO + O_2 \rightarrow 2CO_2$$
$$2C_nH_{2n+2} + (3n + 1)O_2 \rightarrow 2nCO_2 + (2n+2)H_2O$$
$$2CH_2O + 2O_2 \rightarrow 2CO_2 + 2H_2O \text{ (formaldehyde oxidation)}$$

Oxidation catalysts have the potential to achieve a 90% reduction in uncontrolled CO emissions at steady state operation. VOC and organic HAP reduction capabilities are generally expected to be less.

FIGURE 2-5. Image of the GE 7HA class heavy duty CT showing the dry low NOx combustors and compressor and power sections (from GE Company).



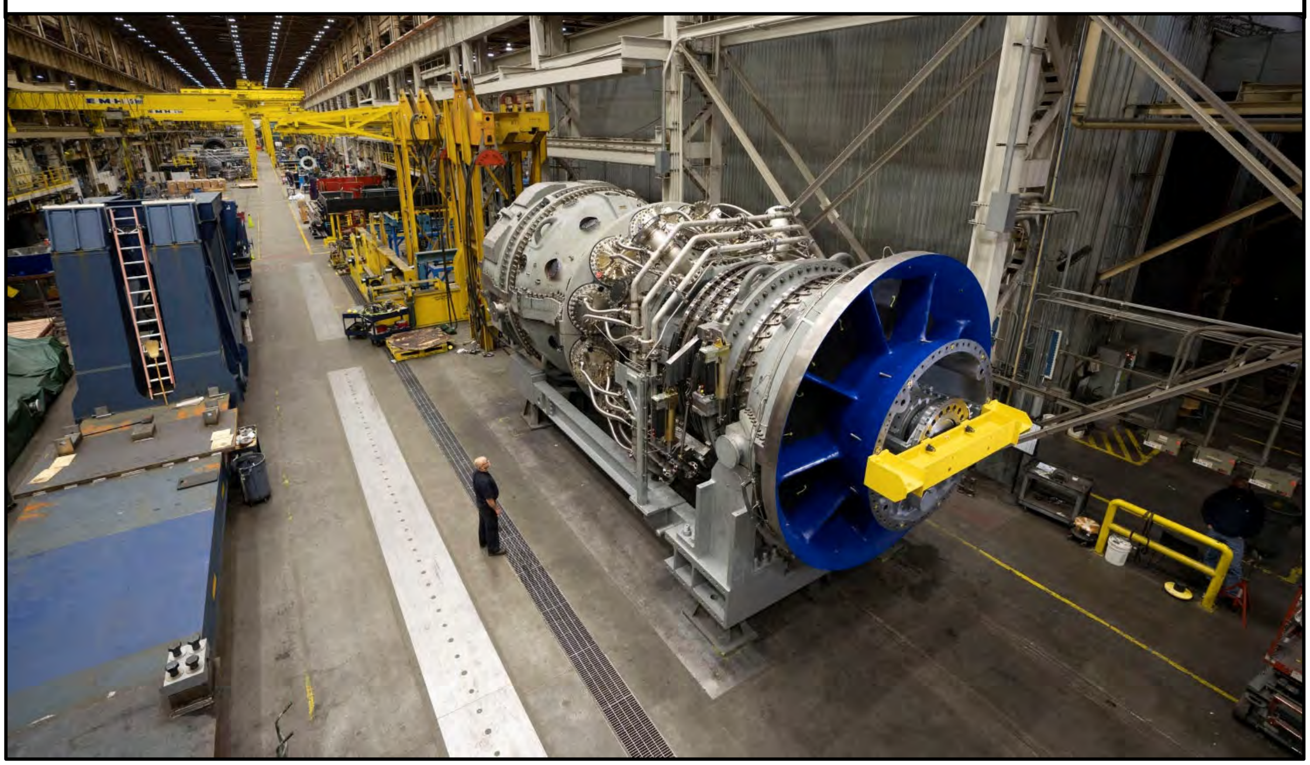


FIGURE 2-6. GE 7HA heavy duty CT and the general specifications for the family of combined cycle units (GE Company).

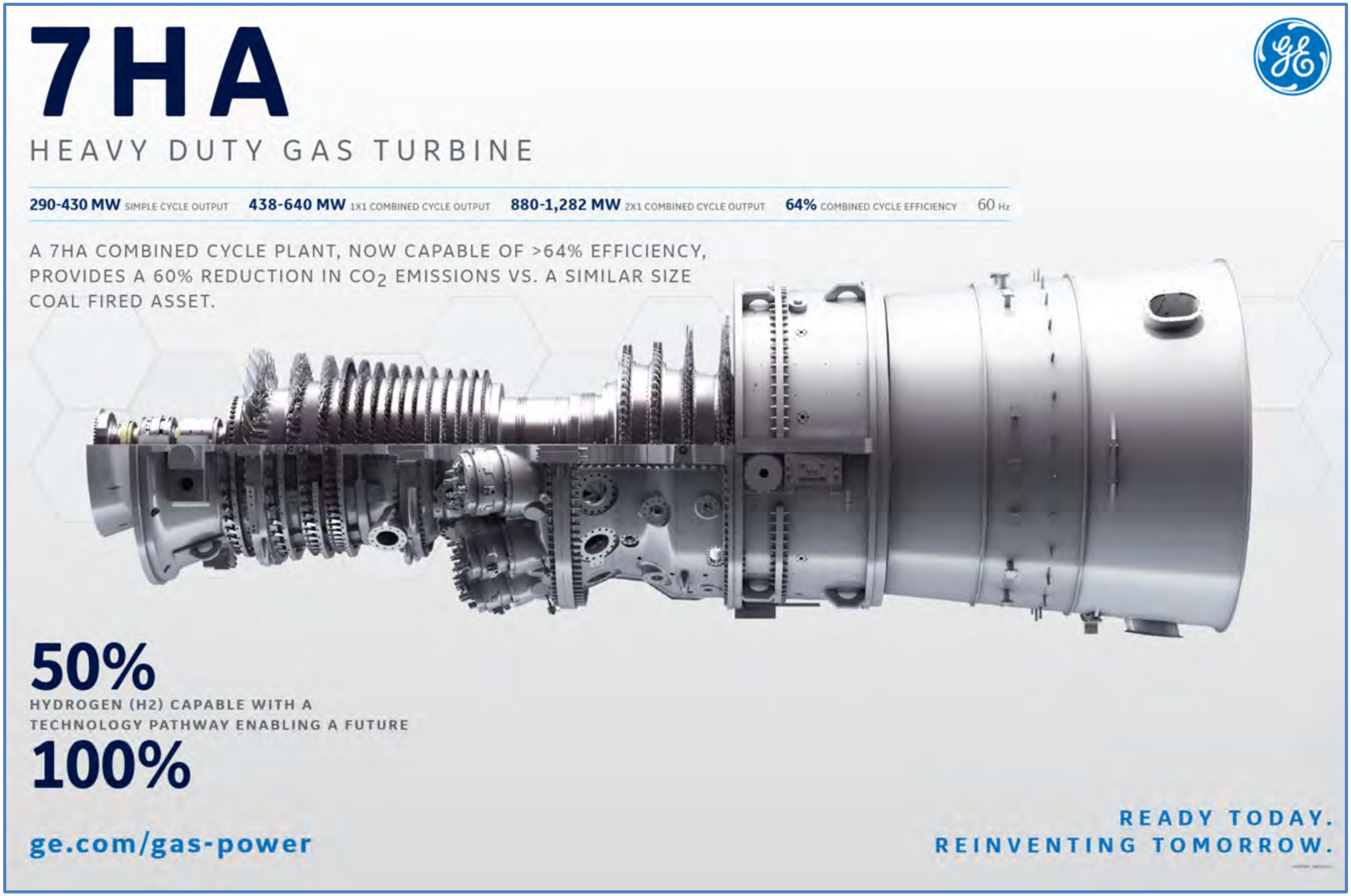
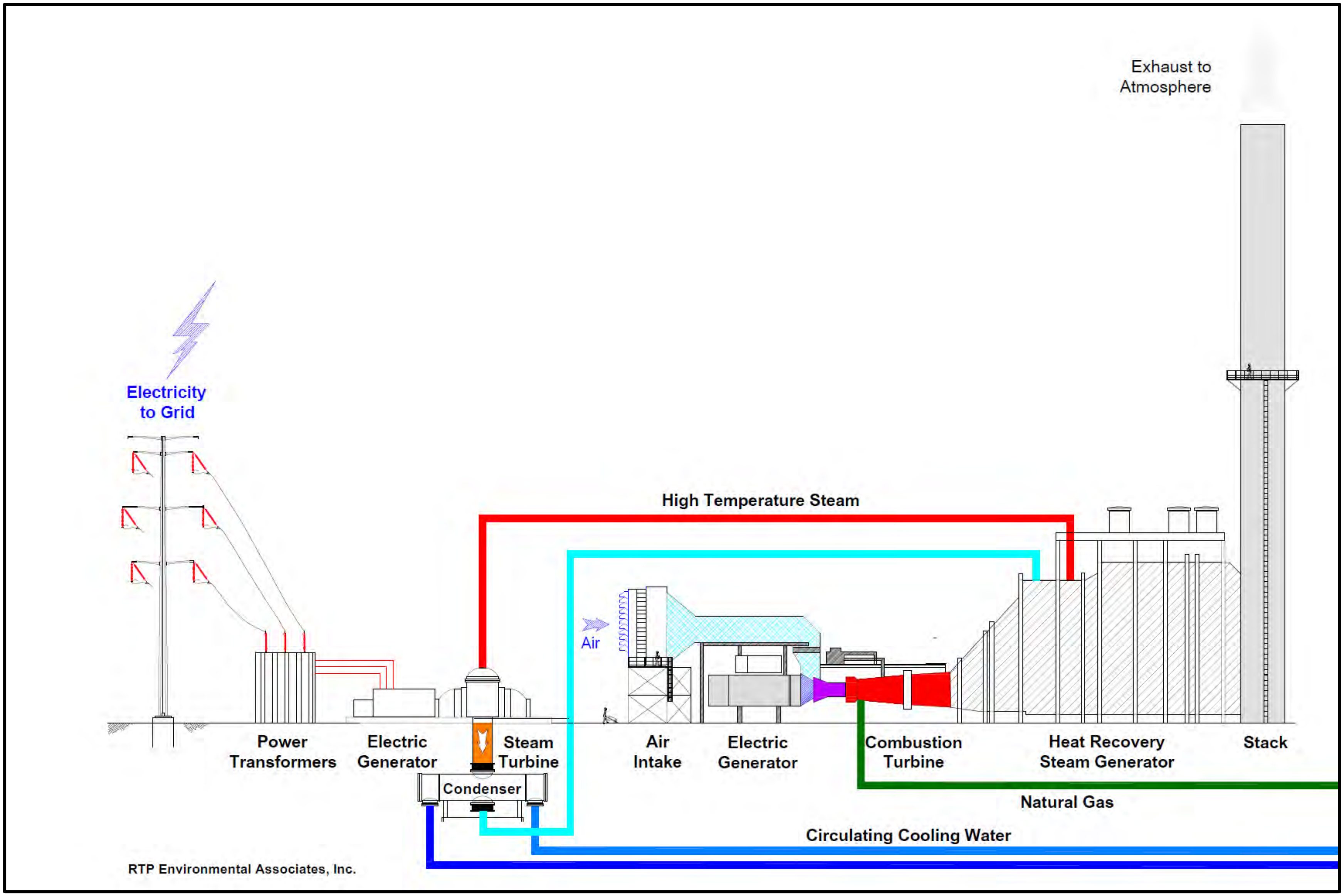


FIGURE 2-7. Schematic drawing of a typical 1 x 1 combined cycle combustion turbine electric generating unit.



2.4 Balance of Plant Equipment.

The proposed Desert Sun Power Plant will also include the following equipment:

1. One (1) natural gas-fired auxiliary boiler,
2. One (1) natural gas-fired natural gas conditioning heater,
3. Two (2) mechanical draft cooling towers,
4. One (1) emergency fire pump,
5. Natural gas piping systems, and
6. Sulfur hexafluoride (SF_6) insulated high voltage circuit breakers.

2.5 Purpose and Need.

The purpose of the Desert Sun Power Plant combined cycle electric generating units is to supply reliable, high-capacity electric service needed to serve the rapidly growing large customer load in Maricopa County, including data centers and other energy-intensive users. Demand from these customers has increased significantly in recent years and now exceeds the capacity that can be served by the existing electric generating infrastructure. These units are needed to provide firm, dispatchable electric power capable of operating during periods of grid stress and extreme weather conditions, ensuring system reliability and supporting continued economic development. These high-efficiency units will complement renewable electric power generation including solar and wind power by providing dependable capacity, fast response, and grid support needed to maintain stable service as the load of the APS system grows.

A critical component of this Project is that the proposed combined cycle units are very high efficiency, baseload units which can provide much-needed energy during any time of the day and for continuous periods, creating a strong complement to renewable energy resources such as solar. The proposed units will also provide dynamic voltage control for the electric grid. Dynamic voltage control is the ability of a generating resource to maintain voltage levels within acceptable limits. This Project will also provide system electric inertia (kinetic energy stored during the units' operation) and frequency response (the ability of a generating resource to aid balance between generation and load on the grid) necessary for electric system stability. Batteries and renewable energy systems such as wind and solar cannot provide this necessary grid support. These attributes of the proposed combined cycle units are critical when the electric supply resource portfolio includes more and more intermittent, renewable resources such as wind and solar.

2.6 Project Schedule.

The following is the expected schedule for the construction and operation of the Desert Sun Power Plant.

Submit Air Quality Operating Permit Application .... May 2026
Begin Detailed Engineering .... June 2026
Draft Permit Issue Date .... May 2027
Final Permit Issue Date .... August 2027
Begin Actual Construction .... May 2028
Initial Operation of the Combined Cycle CTs.. 2029

Chapter 3. Criteria and PSD Air Pollutant Emissions Analysis.

3.1 Combined Cycle CT Units CT1 and CT2.

Potential emissions for these new GE Vernova 7HA.02 combined cycle CTs are based on the use of DLN combustion and selective catalytic reduction (SCR) for nitrogen oxides (NO_x) control and oxidation catalysts for CO, VOC, and organic HAP control. This emissions analysis is also based on the proposed Best Available Control Technology (BACT) emission limits as detailed in Chapter 4 of this application.

3.1.1 Normal Operation.

During normal operation, the combined cycle CTs will have two general modes of operation; operation with duct firing, and operation without duct firing. The maximum potential hourly PSD regulated pollutant emission rates for each CT during normal operation with and without duct firing are summarized in Table 3-1. The potential emissions in Table 3-1 are based on the maximum rated heat input to the CTs and the maximum rated heat input capacity to the duct burners at the worst-case ambient condition which is generally 20 ^{o}F.

Sulfur dioxide (SO_2) emissions are based on firing *pipeline natural gas* as defined in the Acid Rain Program in 40 CFR § 72.2. The CTs will be affected units under the Acid Rain Program (ARP) in 40 CFR Parts 72 – 75. In accordance with 40 CFR § 72.2, *Gas-fired* means, for purposes under the ARP, the combustion of natural gas or other gaseous fuel for at least 90.0 percent of the unit's average annual heat input during the previous three calendar years and for at least 85.0 percent of the annual heat input in each of those calendar years. Because these units will be permitted to fire only natural gas, these units will be *gas-fired units*. The specific SO_2 emission record provisions for *gas-fired units* using the methods in 40 CFR Part 75, Appendix D are specified in 40 CFR § 75.58(c)(4). This section states that when firing pipeline natural gas, SO_2 emissions may be reported using the default SO_2 emission rate of 0.0006 lb/mmBtu. To be consistent with the ARP, potential SO_2 emissions for natural gas combustion are based on the use of this default SO_2 emission rate of 0.0006 lb/mmBtu.

3.1.2 Startup and Shutdown Emissions.

The CT air pollution control systems including the dry low NO_x combustion systems, SCR, and oxidation catalyst systems are not operational during periods of startup and shutdown (SU/SD) because the exhaust gas temperatures are too low for these systems to function as designed. In addition, the DLN combustors cannot operate in the full premix mode until sufficient fuel flow is delivered to allow for full fuel and air premixing. As a result, CO, NO_x, and VOC emissions may be elevated during periods of startup and shutdown.

The time required to startup and shutdown a combined cycle CT is limited by the temperatures inside the heat recovery steam generator (HRSG) and the steam turbine. Severe and potentially hazardous plant conditions can occur if the HRSG or steam turbine are heated too rapidly. As a result, combined cycle CTs have three types of startup events depending on the status of the HRSG, designated as cold, warm, and hot startup. These startup are defined as follows:

> ***Hot Startup*** is defined as taking place within 8 hours after the previous shutdown. The typical duration is 30 minutes.
>
> ***Warm Startup*** is defined as taking place more than 8 hours but less than 72 hours after the previous shutdown. The typical duration is 60 minutes.
>
> ***Cold Startup*** is defined as taking place more than 72 hours after the previous shutdown. The typical duration is 70 minutes.

Cold startup events generally occur after a major unit outage such as a scheduled unit maintenance outage or a significant unit malfunction. Conversely, warm and hot startup events can occur much more frequently. ***Because warm startup and hot startup events can occur interchangeably depending on the day to day operation of the units, potential SU/SD emissions are based on the higher warm startup emissions and a maximum of 350 warm startup events per year.*** Shutdown events are essentially the same after any type of startup event with a typical duration of 12 minutes.

Table 3-2 is a summary of the startup and shutdown emissions, including the expected fuel consumption, expressed as mmBtu, and the PSD regulated air pollutant emissions. ***Note that the startup and shutdown durations, heat input, and emissions, expressed in pounds per event, are the maximum expected values.***

Also, please note that the emission rates for PM, PM_{10}, and $PM_{2.5}$ emissions, as well as SO_2, sulfuric acid mist, lead (Pb), CO_2, and GHG emissions, expressed in pounds per million Btu of heat input (lb/mmBtu), are NOT elevated during periods of startup and shutdown. Therefore, the highest mass emission rate for these pollutants, expressed in pounds per hour, occurs during normal operation at 100% of the rated capacity of the CTs and with duct firing Further, the total mass emissions of PM, PM_{10}, $PM_{2.5}$, SO_2, sulfuric acid mist, lead (Pb), CO_2, and GHG emissions, expressed in tons per year, can be accumulated based only on heat input and the respective pollutant emission rate, expressed in lb/mmBtu.

3.1.3 Total Potential Emissions for Each Unit.

Table 3-3 is a summary of the total potential emissions for each combined cycle CT based on the proposed emission limits and operational limits detailed in Chapter 4 of this application.

TABLE 3-1. Potential emission rates for each combined cycle CT during normal operation.

Pollutant		WITHOUT DUCT BURNERS				WITH DUCT BURNERS			
		Heat Input	Emission Rate			Heat Input	Emission Rate		
		mmBtu/hr	lb/mmBtu	ppmdv @15% O_2	lb/hr	mmBtu/hr	lb/mmBtu	ppmdv @15% O_2	lb/hr
Carbon Monoxide	CO	3,740	0.0045	2.0	16.8	4,750	0.0045	2.0	21.4
Nitrogen Oxides	NO_x	3,740	0.0074	2.0	27.7	4,750	0.0074	2.0	35.2
Particulate Matter	PM	3,740	0.0040		15.0	4,750	0.0060		28.5
Particulate Matter	PM_{10}	3,740	0.0040		15.0	4,750	0.0060		28.5
Particulate Matter	$PM_{2.5}$	3,740	0.0040		15.0	4,750	0.0060		28.5
Sulfur Dioxide	SO_2	3,740	0.0006		2.2	4,750	0.0006		2.9
Vol. Org. Cmpds	VOC	3,740	0.0013	1.0	5.0	4,750	0.0025	2.0	12.1
Sulfuric Acid Mist	H_2SO_4	3,740	0.00018		0.67	4,750	0.00018		0.86
Fluorides (F)	F	3,740	0.00000		0.00	4,750	0.00000		0.00
Lead	Pb	3,740	).0000005		0.0019	4,750	).0000005		0.0024
Carbon Dioxide	CO_2	3,740	117.0		437,491	4,750	117.0		555,636
Greenhouse Gases	CO_2e	3,740	117.1		437,940	4,750	117.1		556,207

Footnotes

1. Potential hourly emissions are based on the maximum heat input to the CTs of 3,740 mmBtu per hour, and the maximum heat input capacity to the duct burners of 940 mmBtu per hour.
2. CO and NO_x emissions during normal operation are calculated based on concentrations of 2.0 parts per million on a dry volume basis (ppmdv) corrected to 15% excess oxygen for both pollutants according to the following equations from 40 CFR Part 60, Appendix A, Reference Method 19, Eq. 19-1 and 40 CFR Part 75, Appendix F, Eq. F-5:

$$E_{NOx} = K_{NOx}\, C_d\, F_d\, \frac{20.9}{20.9 - \%O_{2d}} \qquad E_{CO} = K_{CO}\, C_d\, F_d\, \frac{20.9}{20.9 - \%O_{2d}}$$

Where,
- E = Pollutant emission rate, lb/mmBtu
- C_d = Pollutant concentration during unit operation, parts per million, dry volume basis
- F_d = *F-factor* = 8,710 dscf/mmBtu for natural gas
- $\%O_2$ = Oxygen concentration, percent by volume, dry basis, = 15%
- K_{CO} = 7.237×10^{-8} lb/dscf-ppm CO
- K_{NOx} = 1.194×10^{-7} lb/dscf-ppm NO_x

3. PM, PM_{10}, and $PM_{2.5}$ emissions are based on a proposed BACT emission rate of 15.0 pounds per hour without duct firing, and 28.0 pounds per hour with duct firing.
4. All filterable plus condensable PM_{10} emissions are also assumed to be $PM_{2.5}$ emissions.
5. The sulfur dioxide (SO_2) emission rate is based on the Acid Rain Program default SO_2 emission rate for pipeline natural gas as specified in 40 CFR § 75.58(c)(4) of 0.0006 lb/mmBtu.
6. VOC emissions are based on a proposed BACT emission rate of 5.0 pounds per hour without duct firing, and 12.1 pounds per hour with duct firing, expressed as methane (CH_4).
7. Sulfuric acid mist emissions are based on a 50% conversion of SO_2 to sulfuric acid on a mass basis.
8. Lead (Pb) emissions are based on the emission factor from the U.S. EPA's *AP-42*, Table 1.4-2.
9. The emission factors for greenhouse gases including CO_2, N_2O and CH_4 are from 40 CFR 98, Tables C-1 and C-2. The CO_2e factors are from 40 CFR 98, Subpart A, Table A-1.

TABLE 3-2. Maximum emission rates for each GE 7HA.02 combined cycle CT during startup and shutdown.

Pollutant		Cold Start				Warm Start				Hot Start (*see footnote*)				Shutdown				TOTAL COMBINED SU/SD EMISSIONS	
		Heat Input mmBtu	lb / event	events / year	ton / year	Heat Input mmBtu	lb / event	events / year	ton / year	Heat Input mmBtu	lb / event	events / year	ton / year	Heat Input mmBtu	lb / event	events / year	ton / year	lb / event	ton / year
Carbon Monoxide	CO	1,870	830	16	6.6	1,640	235	350	41.1	775	215	350	37.6	200	185	366	33.9	1,015	81.6
Nitrogen Oxides	NO_x	1,870	200	16	1.6	1,640	160	350	28.0	775	110	350	19.3	200	16	366	2.9	216	32.5
Particulate Matter	PM	1,870	9.4	16	0.07	1,640	8.2	350	1.44	775	3.9	350	0.68	200	1.0	366	0.18	10	1.7
Particulate Matter	PM_{10}	1,870	9.4	16	0.07	1,640	8.2	350	1.44	775	3.9	350	0.68	200	1.0	366	0.18	10	1.7
Particulate Matter	$PM_{2.5}$	1,870	9.4	16	0.07	1,640	8.2	350	1.44	775	3.9	350	0.68	200	1.0	366	0.18	10	1.7
Sulfur Dioxide	SO_2	1,870	1.12	16	0.01	1,640	0.98	350	0.17	775	0.47	350	0.08	200	0.12	366	0.02	1.2	0.2
Vol. Org. Cmpds	VOC	1,870	105	16	0.8	1,640	70	350	12.3	775	66	350	11.6	200	55	366	10.1	160	23.2
Sulfuric Acid Mist	H_2SO_4	1,870	0.70	16	0.006	1,640	0.62	350	0.108	775	0.29	350	0.051	200	0.08	366	0.014	0.78	0.05
Fluorides (F)	F	1,870	0.0000	16	0.0	1,640	0.0000	350	0.000	775	0.0000	350	0.000	200	0.0000	366	0.000	0.0000	0.0000
Lead	Pb	1,870	0.0009	16	0.00001	1,640	0.0008	350	0.000	775	0.0004	350	0.000	200	0.0001	366	0.000	0.0010	0.0002
Carbon Dioxide	CO_2	1,870	218,745	16	1,750.0	1,640	191,841	350	33,572.1	775	90,656	350	15,865	200	23,395	366	4,281.3	242,140	39,603
Greenhouse Gases	CO_2e	1,870	218,970	16	1,751.8	1,640	192,038	350	33,606.6	775	90,750	350	15,881	200	23,419	366	4,285.7	242,389	39,644

Footnote

Because warm startup and hot startup events can occur interchangeably, potential emissions are based on the higher warm startup emissions and a maximum of 350 warm startup events per year.

The total startup and shutdown emissions in tons per year is the sum of the 16 cold startup events, 350 warm startup events, and 366 shutdown events.

TABLE 3-3. Potential emissions for each new GE Vernova 7HA.02 combined cycle CT based on the proposed limits in this application.

Pollutant		NORMAL OPERATION WITHOUT DUCT BURNERS						NORMAL OPERATION WITH DUCT BURNERS						STARTUP/SHUTDOWN				TOTAL POTENTIAL TO EMIT
		Heat Input	Emission Rate			Operation	Emissions	Heat Input	Emission Rate			Operation	Emissions	Cold Start	Warm / Hot Start	Shut-down	TOTAL	
		mmBtu/ hr	lb/ mmBtu	ppmdv @15% O_2	lb/hr	hr/year	ton/year	mmBtu/ hr	lb/ mmBtu	ppmdv @15% O_2	lb/hr	hr/year	ton/year	ton/year	ton/year	ton/year	ton/year	ton/year
Carbon Monoxide	CO	3,740	0.0045	2.0	16.8	6,760	56.9	4,750	0.0045	2.0	21.4	2,000	21.4	6.6	41.1	33.9	81.6	159.9
Nitrogen Oxides	NO_x	3,740	0.0074	2.0	27.7	6,760	93.5	4,750	0.0074	2.0	35.2	2,000	35.2	1.6	28.0	2.9	32.5	161.2
Particulate Matter	PM	3,740	0.0040		15.0	6,760	50.7	4,750	0.0060		28.5	2,000	28.5	0.07	1.44	0.18	1.7	79.2
Particulate Matter	PM_{10}	3,740	0.0040		15.0	6,760	50.7	4,750	0.0060		28.5	2,000	28.5	0.07	1.44	0.18	1.7	79.2
Particulate Matter	$PM_{2.5}$	3,740	0.0040		15.0	6,760	50.7	4,750	0.0060		28.5	2,000	28.5	0.07	1.44	0.18	1.7	79.2
Sulfur Dioxide	SO_2	3,740	0.0006		2.2	6,760	7.6	4,750	0.0006		2.9	2,000	2.9	0.01	0.17	0.02	0.2	10.4
Vol. Org. Cmpds	VOC	3,740	0.0013	1.0	5.0	6,760	16.9	4,750	0.0025	2.0	12.1	2,000	12.1	0.8	12.3	10.1	23.2	52.2
Sulfuric Acid Mist	H_2SO_4	3,740	0.00018		0.67	6,760	2.3	4,750	0.00018		0.86	2,000	0.9	0.00	0.04	0.01	0.05	3.1
Fluorides (F)	F	3,740	0.0000		0.00	6,760	0.0000	4,750	0.0000		0.00	2,000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Lead	Pb	3,740	0.0000		0.0019	6,760	0.0063	4,750	0.0000		0.0024	2,000	0.0024	0.0000	0.0001	0.0000	0.0002	0.0087
Carbon Dioxide	CO_2	3,740	117.0		437,491	6,760	1,478,718	4,750	117.0		555,636	2,000	555,636	1,750	33,572	4,281	39,603	2,034,354
Greenhouse Gases	CO_2e	3,740	117.1		437,940	6,760	1,480,237	4,750	117.1		556,207	2,000	556,207	1,752	33,607	4,286	39,644	2,036,444

Footnotes

1. Potential hourly emissions are based on the maximum heat input to the CTs of 3,740 mmBtu per hour, and the maximum heat input capacity to the duct burners of 1,010 mmBtu per hour.
2. CO and NO_x emissions during normal operation are calculated based on concentrations of 2.0 parts per million on a dry volume basis (ppmdv) corrected to 15% excess oxygen for both pollutants.
3. PM, PM_{10}, and $PM_{2.5}$ emissions are based on a proposed BACT emission rate of 15.0 pounds per hour without duct firing, and 28.5 pounds per hour with duct firing.
4. All filterable plus condensable PM_{10} emissions are also assumed to be $PM_{2.5}$ emissions.
5. The sulfur dioxide (SO_2) emission rate is based on the Acid Rain Program default SO_2 emission rate for pipeline natural gas as specified in 40 CFR § 75.58(c)(4) of 0.0006 lb/mmBtu.
6. VOC emissions are based on a proposed BACT emission rate of 5.0 pounds per hour without duct firing, and 12.1 pounds per hour with duct firing, expressed as methane (CH_4).
7. Sulfuric acid mist emissions are based on a 50% conversion of SO_2 to sulfuric acid on a mass basis.
8. Lead (Pb) emissions are based on the emission factor from the U.S. EPA's *Compilation of Air Pollutant Emission Factors*, *AP-42*, 5^{th} Edition, Table 1.4-2.
9. The emission factors for greenhouse gases including CO_2, N_2O and CH_4 are from 40 CFR 98, Tables C-1 and C-2. The CO_2e factors are from 40 CFR 98, Subpart A, Table A-1.
10. Because warm startup and hot startup events can occur interchangeably, potential emissions for warm and hot startup events are based on the higher warm startup emissions per event and a maximum of 350 warm startup events per year.

3.2 Auxiliary Boiler.

The Desert Sun Power Plant will include one (1) natural gas-fired auxiliary boiler which can be used to provide steam to preheat the combined cycle CT heat recovery steam generators (HRSG) and the steam turbines. This boiler will fire only natural gas and will have a maximum design heat input capacity of 90 mmBtu per hour.

This boiler will be subject to the *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, 40 CFR 60 Subpart Dc. This subpart establishes emission standards for filterable particulate matter (PM) and sulfur dioxide (SO_2) emissions, and applies to each steam generating unit that commences construction after June 9, 1989 and that has a maximum design heat input capacity of 100 mmBtu per hour or less, but greater than or equal to 10 mmBtu per hour. However, the emission standards for PM and SO_2 do not apply to units that fire only natural gas. In accordance with the reporting and recordkeeping requirements in 40 CFR § 60.48c(g)(2), the owner or operator of an affected facility that combusts only natural gas using fuel certification in § 60.48c(f) to demonstrate compliance with the SO_2 standard, or fuels not subject to an emissions standard (excluding opacity), may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

With this application, APS is also proposing a federally enforceable heat input limit of 90,000 mmBtu in any consecutive 12-month period. This heat input limit is equal to an annual capacity factor of approximately 10 percent.

This boiler will be equipped with modern low NO_x burners which will limit NO_x emissions to less than 30 ppmdv at 3% O_2, and limit CO emissions to less than 50 ppmdv at 3% O_2. These emission rates concentrations may be converted to lb/mmBtu based on the following equation:

$$E = \frac{20.9 K C_h F}{20.9 - \%O_2}$$

Where, E = Pollutant emission rate, lb/mmBtu

K_{NOx} = 1.194×10^{-7} lb NO_x/scf-ppm NO_x

K_{CO} = 7.590×10^{-8} lb CO/scf-ppm CO

C_h = Pollutant concentration, ppmdv

F = Fuel-based Factor = 8,710 dscf/mmBtu

Substituting these values into the above equation, NO_x emissions of 30 ppmdv at 3% O_2 is equal to an emission rate of 0.037 lb NO_x/mmBtu, and CO emissions of 50 ppmdv at 3% O_2 is equal to an emission rate of 0.040 lb CO/mmBtu. Potential emissions for the auxiliary boiler based on this heat input limit and the proposed BACT emission limits in this application are included in Table 3-4.

TABLE 3-4. Potential emissions for the auxiliary boiler.

Pollutant		Emission Factor		Heat Input Rate		Potential to Emit	
		lb/mmcf	lb/mmBtu	mmBtu/hr	mmBtu/yr	lb/hr	ton/year
Carbon Monoxide	CO	40.0	0.040	90	90,000	3.60	1.80
Nitrogen Oxides	NO_x	37.0	0.037	90	90,000	3.33	1.67
Particulate Matter	PM	7.6	0.0076	90	90,000	0.68	0.34
Particulate Matter	PM_{10}	5.0	0.005	90	90,000	0.45	0.23
Particulate Matter	$PM_{2.5}$	5.0	0.005	90	90,000	0.45	0.23
Sulfur Dioxide	SO_2	0.6	0.0006	90	90,000	0.05	0.03
Vol. Org. Cmpds	VOC	5.5	0.0055	90	90,000	0.50	0.25
Sulfuric Acid Mist	H_2SO_4		0.00006	90	90,000	0.005	0.003
Fluorides (as HF)	HF			90	90,000	0.000000	0.00
Lead	Pb	0.0005	0.0000005	90	90,000	0.000045	0.00002
Carbon Dioxide	CO_2	116,976	117.0	90	90,000	10,527.8	5,263.9
Greenhouse Gases	CO_2e	117,096	117.1	90	90,000	10,538.7	5,269.3

Footnotes

1. Potential annual emissions are based on an annual capacity factor limit of 10 percent.
2. CO emissions are based on a concentration of 50 ppmdv at 3% O_2, respectively.
3. NO_x emissions are based on a concentration of 30 ppmdv at 3% O_2, respectively.
4. Emission factors for uncontrolled PM, SO_2, and lead (Pb) emissions are for uncontrolled natural gas-fired boilers from the U.S. EPA document *AP-42, Compilation of Air Pollutant Emission Factors*, 5th Edition, section 1.4, Tables 1.4-1 and 1.4-2. The emission rate in pounds per million cubic feet of gas (lb/mmcf) was converted to pounds per million Btu based on a natural gas heat content of 1,000 mmBtu per mmcf.
5. Emission factors for uncontrolled PM_{10} and $PM_{2.5}$ are from the manufacturer.
6. Sulfuric acid mist emissions are based on 10% conversion of SO_2 to SO_3.
7. Natural gas does not contain significant amounts of fluorine. Therefore, fluoride emissions are expected to be insignificant.
8. Greenhouse gas (GHG) emissions are based on the emission factors for CO_2, N_2O and CH_4 are from 40 CFR 98, Tables C-1 and C-2. The CO_2e factors are from 40 CFR 98, Subpart A, Table A-1.

Pollutant		Emission Factor	Total GHG Emission Factor	
		lb/mmBtu	CO_2e Factor	lb/mmBtu
Carbon Dioxide	CO_2	116.98	1	116.976
Methane	CH_4	0.0022	28	0.062
Nitrous Oxide	N_2O	0.00022	265	0.058
TOTAL GHG EMISSIONS, AS CO_2e				**117.1**

3.3 Natural Gas-Fired Natural Gas Heater.

The natural gas used for the Desert Sun Power Plant will be supplied from a high-pressure natural gas transmission line. The natural gas pressure must be reduced from the transmission pressures for use in the CTs and auxiliary boiler. When the gas pressure is reduced, the gas experiences adiabatic cooling which can cause condensation of natural gas components and fuel handling problems. To ensure that this does not happen, the project will include a natural gas-fired natural gas heater with a maximum rated heat input capacity of 45 mmBtu per hour. Table 3-5 summarizes the potential emissions for the natural gas-fired natural gas heater based on 8,760 hours per year of operation and the BACT limits in this application.

TABLE 3-5. Potential emissions for the natural gas-fired heater.

Pollutant		Emission Factor		Heat Input	Potential to Emit	
		lb/mmcf	lb/mmBtu	mmBtu/hr	lb/hr	ton/year
Carbon Monoxide	CO	40.0	0.040	45	1.80	7.88
Nitrogen Oxides	NO_x	11.0	0.011	45	0.50	2.17
Particulate Matter	PM	7.6	0.0076	45	0.34	1.50
Particulate Matter	PM_{10}	5.0	0.005	45	0.23	0.99
Particulate Matter	$PM_{2.5}$	5.0	0.005	45	0.23	0.99
Sulfur Dioxide	SO_2	0.6	0.0006	45	0.027	0.12
Vol. Org. Cmpds	VOC	5.5	0.0055	45	0.248	1.08
Sulfuric Acid Mist	H_2SO_4		0.000060	45	0.0027	0.012
Fluorides (as HF)	HF			45	0.000000	0.00
Lead	Pb	0.0005	0.0000005	45	0.000023	0.00010
Carbon Dioxide	CO_2	116,976	117.0	45	5,263.9	23,056.0
Greenhouse Gases	CO_2e	117,096	117.1	45	5,269.3	23,079.7

Footnotes

1. Potential annual emissions are based on 8,760 hours per year of operation.
2. CO emissions are based on a concentration of 50 ppmdv at 3% O_2, respectively.
3. NO_x emissions are based on a concentration of 9 ppmdv at 3% O_2, respectively.
4. Emission factors for uncontrolled PM, SO_2, and lead (Pb) emissions are for uncontrolled natural gas-fired boilers from the U.S. EPA document *AP-42, Compilation of Air Pollutant Emission Factors*, 5th Edition, section 1.4, Tables 1.4-1 and 1.4-2. The emission rate in pounds per million cubic feet of gas (lb/mmcf) was converted to pounds per million Btu based on a natural gas heat content of 1,000 mmBtu per mmcf.
5. Emission factors for uncontrolled PM_{10} and $PM_{2.5}$ are from the manufacturer.
6. Sulfuric acid mist emissions are based on 10% conversion of SO_2 to SO_3.
7. Natural gas does not contain significant amounts of fluorine. Therefore, fluoride emissions are expected to be insignificant.
8. Greenhouse gas (GHG) emissions are based on the emission factors for CO_2, N_2O and CH_4 are from 40 CFR 98, Tables C-1 and C-2. The CO_2e factors are from 40 CFR 98, Subpart A, Table A-1.

3.4 Cooling Towers.

The combined cycle CTs will utilize closed cycle, air cooled condensers to condense the steam exhausted from the steam turbine. All four CTs will also utilize a Closed Cooling Water (CCW) system to provide cooling for each of the CTs and, for the combined cycle units, the steam turbine - electric generator set. The CCW will use air cooled fin-fan heat exchangers which act much like a car's radiator to provide cooling of the CCW up to an ambient temperature of approximately 110 ^{o}F. Above 110 ^{o}F, small wet cooling towers for each CT will provide supplemental cooling. This configuration will minimize the size of the wet cooling towers and minimize water consumption. The new wet cooling towers will be single cell, counter flow cooling towers. The specifications for each cooling tower are summarized below.

Specifications for the new mechanical draft cooling tower.

Total Circulating Water Flow, gallons per minute	4,000
Number of Cells	2
Maximum Total Dissolved Solids, ppm	2,000
Design Drift Loss, %	0.0005%
Release Height, feet	25
Exit Diameter per cell, feet	12
Volumetric Air Flow of each Cell, acfm	10,000

In a mechanical draft cooling tower, the circulating cooling water is introduced into the top of the tower. As the water falls through the tower, a fan induces an air flow in a countercurrent direction. A portion of the circulating water evaporates, cooling the remaining water. A much smaller amount of the water may be entrained in the induced air flow in the form of liquid phase droplets or mist called *drift*. When these droplets evaporate, the dissolved solids in the droplet become particulate matter. Therefore, cooling towers are sources of PM, PM_{10}, and $PM_{2.5}$ emissions.

Drift eliminators are used at the outlet of cooling towers to reduce the amount of water droplets entrained in the air. Drift eliminators are typically blades configured in a chevron pattern which cause the water droplets to impact these blades and fall back into the tower. The mist eliminators will be designed to reduce the drift loss to 0.0005% of the circulating water flow. Cooling tower PM emissions are calculated based on the circulating water flow rate, the total dissolved solids (TDS) in the circulating water, and the design drift loss according to the following equation:

$$E = kQ\left(\frac{60\text{ min}}{\text{hour}}\right)\left(\frac{8.345\text{ lb water}}{\text{gal water}}\right)\left(\frac{C_{TDS}}{10^6}\right)\left(\frac{\%DL}{100}\right)$$

Where,	E	=	Particulate matter emissions, pounds per hour, lb/hr		
	Q	=	Circulating water flow rate, gallons per minute	=	4,000 gpm
	C_{TDS}	=	Circulating water total dissolved solids, parts per million	=	2,000 ppm
	%DL	=	Drift loss, %	=	0.0005%
	k	=	particle size multiplier, dimensionless		

The particle size multiplier "*k*" has been added to the basic AP-42 equation to calculate emissions for PM_{10} and $PM_{2.5}$. AP-42 Section 13.4 presents data that suggests the PM_{10} fraction is 1% of the total PM emission rate. AP-42 has no information on $PM_{2.5}$ emissions. For this analysis, the value of the particle size multiplier is based on the measured distribution of water droplet size in the cooling tower drift loss. The diameter of the airborne particle that would be produced by the evaporation of the liquid water from a drift droplet is given by the following equation from the report *Calculating Realistic PM_{10} Emissions from Cooling Towers*, Abstract No. 216 Session No. AM-1b, Joel Reisman and Gordon Frisbie, Greystone Environmental Consultants, Inc. This analysis is based on actual measured data from the Electric Power Research Institute (EPRI) for a large cooling tower.

$$d_{droplet} = d_{particle}\left[\frac{10^6 \rho_{salt}}{\rho_{water} C_{TDS}}\right]^{1/3}$$

Where,	$d_{droplet}$	=	Maximum diameter of the drift droplet that would produce a dry particle size of $d_{particle}$ or smaller, microns (µm)
	$d_{particle}$	=	Dry particle (particulate matter) particle size, microns
	ρ_{salt}	=	Density of particle = 2.5 g/cm^3
	ρ_{water}	=	Density of water = 1.0 g/cm^3
	C_{TDS}	=	Circulating water total dissolved solids (TDS), parts per million, ppm

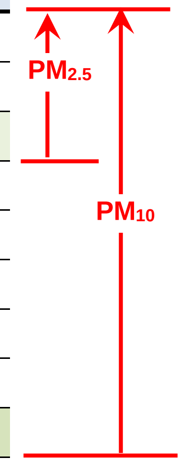
Table 3-7 is the drift loss droplet size distribution as measured for a large cooling tower from the above referenced EPRI report. For a circulating water TDS of 2,000 ppm, the drift loss droplet size would need to be smaller than 108 µm to form PM_{10} emissions, and less than 27 µm to form $PM_{2.5}$. From Table 3-8, 70.5% of the drift loss would result in PM_{10} emissions, and 0.23% of the drift loss would result in $PM_{2.5}$ emissions. Table 3-6 summarizes the maximum PM, PM_{10}, and $PM_{2.5}$ emissions for the cooling tower based on particle size multiplier "*k*" values of 1.0, 0.705, and 0.0023, respectively.

TABLE 3-6. Total potential emissions for each mechanical draft cooling tower.

POLLUTANT		Q Flowrate	C_{TDS} TDS Conc.	%DL Drift Loss	*k* Particle Size Multiplier	Potential Emissions	
		gal/min	ppm	%		lb/hr	ton/yr
Particulate Matter	PM	4,000	2,000	0.0005%	1.00	0.0200	0.088
Particulate Matter	PM_{10}	4,000	2,000	0.0005%	0.705	0.0141	0.062
Particulate Matter	$PM_{2.5}$	4,000	2,000	0.0005%	0.0023	0.000045	0.0002

TABLE 3-7. Size distribution of water droplets for cooling towers and the resulting particle size multiplier, k, for particulate matter (PM) emissions.

EPRI Droplet Diameter, µm	Solid Particle Diameter, µm	Particle Size Multiplier, *k* (EPRI % Mass Smaller)
10	0.90	0.00
20	1.80	0.20
30	**2.70**	**0.23**
40	3.60	0.51
50	4.50	1.82
60	5.40	5.70
70	6.30	21.35
90	8.1	49.81
110	**9.9**	**70.51**
130	11.7	82.02
150	13.5	88.01
180	16.2	91.03
210	18.9	92.47
240	21.6	94.09
270	24.3	94.69
300	27.0	96.29
350	31.5	97.01
400	36.0	98.34
450	40.5	99.07
500	45.0	99.07
600	54.0	100.00



3.5 Diesel Engine Emergency Fire Pump.

The Desert Sun Power Plant will have one new 510 horsepower diesel engine driven fire pump. The specifications for this fire pump are summarized in Table 3-8.

TABLE 3-8. General specifications for the new emergency diesel fire pump.

Manufacturer	Clarke (or similar)
Model	JX6H-UFAD60
Fuel	Diesel Fuel Oil
Engine Type	Diesel
Engine Displacement, liters	13.5
Engine Rating, horsepower	510
Maximum Fuel Flow, gal/hour	27.0

This engine will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* under 40 CFR 60, Subpart IIII. These emission standards are summarized below.

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines], g/kWh (g/Hp-hr)

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +[3]	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)

Potential air pollutant emissions for this new fire pump are summarized in Table 3-10. Potential emissions are based on 200 hours per year of operation. Potential CO, NO_x, and PM emissions are based on the above standards in Table 4 of Subpart IIII. For NO_x emissions, the standard is for the combined total of NO_x plus non-methane hydrocarbons (NMHC + NO_x). As a worst-case assumption in this analysis, potential NO_x emissions assume 100% of the emissions are NO_x emissions. Potential VOC emissions are based on the NMHC + NO_x and assume 100% of the total NMHC + NO_x emissions are also VOC emissions.

TABLE 3-9. Potential emissions for 510 horsepower diesel engine driven fire pump.

POLLUTANT		Fuel Oil Heat Input	Power Output	Emission Factor		Potential Emissions	
		mmBtu/hr	hp	lb/mmBtu	g/hp-hr	lb/hr	ton/year
Carbon Monoxide	CO	4.20	510	0.70	2.6	2.92	0.29
Nitrogen Oxides	NO_x	4.20	510	0.80	3.0	3.37	0.34
Particulate Matter	PM	4.20	510	0.010	0.15	0.17	0.02
Particulate Matter	PM_{10}	4.20	510	0.010	0.15	0.17	0.02
Particulate Matter	$PM_{2.5}$	4.20	510	0.010	0.15	0.17	0.02
Sulfur Dioxide	SO_2	4.20	510	0.0016		0.007	0.0007
Vol. Org. Cmpds	VOC	4.20	510	0.40	3.0	3.37	0.34
Sulfuric Acid Mist	H_2SO_4	4.20	510	0.00040		0.002	0.0002
Fluorides	F	4.20	510	0.0373		0.157	0.0157
Lead	Pb	4.20	510	0.000009		0.00004	0.000004
Carbon Dioxide	CO_2	4.20	510	163.1		684.8	68.5
Greenhouse Gases	CO_2e	4.20	510	163.8		687.9	68.8

Footnotes

1. Potential emissions are based on 200 hours per year of operation at the full output of 510 hp and a diesel oil fuel oil flow of 30 gal/hr, equal to 4.2 mmBtu/hr.

2. The NOx and PM emission factors in g/hp-hr are the emission standards for stationary fire pump engines with ratings of 30 < HP < 600 in 40 CFR 60, Subpart III, Table 4. The CO emission rate is the emission standard for similar model year 2008 and earlier engines.

3. All PM emissions are also assumed to be PM_{10} and $PM_{2.5}$ emissions.

4. The SO_2 emission factor of 0.0016 lb/mmBtu is based on combustion of ultra-low sulfur fuel oil with a sulfur content of less than 15 parts per million (ppm).

5. The VOC emission factor in g/hp-hr is equal to 100% of the emission standard for NOx plus total non-methane hydrocarbons for fire pump engines with ratings of 30 < HP < 600 in 40 CFR 60, Subpart III, Table 4.

6. Sulfuric acid mist emissions are based on 25% conversion of SO_2 to sulfuric acid mist in the flue gas.

7. The lead (Pb) and fluorides emission factors are based on combustion of fuel oil from the U.S. EPA's *Compilation of Air Pollutant Emission Factors*, *AP-42*, 5th Edition, Table 1.3-10 and 1.3-11.

8. The emission factors for the greenhouse gases from fuel oil combustion, including CO_2, N_2O and CH_4 are from 40 CFR 98, Tables C-1 and C-2. The CO_2e factors are from 40 CFR 98, Subpart A, Table A-1.

Pollutant		Emission Factor	Total GHG Emission Factor	
		lb/mmBtu	CO_2e Factor[4]	lb/mmBtu
Carbon Dioxide	CO_2	163.05	1	163.052
Methane	CH_4	0.0132	28	0.370
Nitrous Oxide	N_2O	0.00132	265	0.351
TOTAL GHG EMISSIONS, AS CO_2e				**163.8**

3.6 Natural Gas Piping Systems.

Natural gas piping components including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections can leak and result in fugitive natural gas emissions. Since natural gas consists of from 70 to almost 100% methane, leaks in the natural gas piping can result in methane emissions, and methane is a regulated greenhouse gas.

The Mandatory Greenhouse Gas Reporting Rules in 40 CFR Part 98, Subpart W include methods for estimating GHG emissions from petroleum and natural gas systems. Table 3-10 summarizes the estimated fugitive methane emissions and the equivalent GHG emissions, expressed as CO_2e, which are expected to result from a properly operated and maintained natural gas piping system for new CTs.

Note that these fugitive methane emissions represent 0.04% of the total GHG emissions from the proposed Project.

TABLE 3-10. Potential fugitive emissions from the natural gas piping systems.

Component Type	Component Count	Emission Factor[1] scf / hour / component	Specific Volume[3] scf / lb CH_4	Natural Gas (Methane)[4] ton/year	CO_2e Factor[2]	Potential to Emit ton CO_2e / year
Connectors	450	0.017	19.8	1.69	28	47.5
Flanges	1,390	0.003	19.8	0.92	28	25.9
Valves	1,220	0.123	19.8	33.25	28	930.9
Open Ended Pipes	160	0.123	19.8	4.36	28	122.1
Pump/Compressor Seals	4	13.3	19.8	11.79	28	330.0
Relief Valves	60	0.193	19.8	2.57	28	71.8
TOTAL				**52.9**	**28**	**1,480.7**

Footnotes

1. The emission factors are default whole gas emission factors from 40 CFR Part 98, Table W-1A for onshore natural gas production, Western U.S. In accordance with Table W-1A Footnote 1, for multi-phase flow that includes gas, use the gas service emissions factors.
2. The specific volume of methane at 68 ºF is based on a specific volume of 385.5 standard cubic feet per lb-mole of gas, and a methane molecular weight of 16.0 lb/lb-mole.
3. Methane emissions are based on the worst-case assumption that natural gas is 100% methane by volume.

3.7 Sulfur Hexafluoride (SF_6) Insulated Electrical Equipment.

Under the Prevention of Significant Deterioration (PSD) program sulfur hexafluoride (SF_6), Chemical Abstract Service (CAS) No. 2551-62-4, is also listed as regulated GHG. The new Project will include circuit breakers and switch gear for the CTs which will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable, inert, and non-toxic gas. SF_6 has a very stable molecular structure and has a very high ionization energy which makes it an excellent electrical insulator. The gas is used for electrical insulation, arc suppression, and current interruption in high-voltage electrical equipment.

The electrical equipment containing SF_6 is designed not to leak, because if too much gas leaks out, the equipment may not operate correctly and could become unsafe. State-of-the-art circuit breakers are gas-tight and are designed to achieve a leak rate of less than or equal to 0.5% per year (by weight). This is the same leak rate from the U.S. EPA report, *SF_6 Leak Rates from High Voltage Circuit Breakers - EPA Investigates Potential Greenhouse Gas Emission Source*, J. Blackman, Program Manager, EPA, and M. Avery, ICF Consulting, and Z. Taylor, ICF Consulting. This is also the International Electrotechnical Commission (IEC) maximum leak rate standard.

Table 3-11 summarizes the potential SF_6 emissions for the planned equipment based on this leak rate. Note that these emissions represent 0.02% of the total GHG emissions from the proposed Project.

TABLE 3-11. Potential fugitive SF_6 emissions from high voltage electrical equipment and the equivalent GHG emissions.

Breaker Type	Breaker Count	Total SF_6 per Component pounds	Leak Rate % per year	SF_6 Emissions ton/year	CO_2e Factor[4]	Potential to Emit ton CO_2e /yr
500 kV	2	1,437	0.5%	0.0072	23,500	168.8
345 kV	27	290	0.5%	0.0196	23,500	460.0
230 kV	6	189	0.5%	0.0028	23,500	66.6
145 kV	6	90	0.5%	0.0014	23,500	31.7
69 kV		75	0.5%	0.0000	23,500	0.0
TOTAL FUGITIVE EMISSIONS				**0.0309**	**23,500**	**727.2**

Footnotes

Potential emissions are based on the International Electrotechnical Commission (IEC) maximum leak rate standard of 0.5% per year.

3.8 Total Project Potential PSD and NANSR Regulated Air Emissions.

Table 3-12 summarizes the total potential emissions for the entire Desert Sun Power Plant based on the proposed emission and operating limits in this application.

TABLE 3-12. Total potential PSD regulated air pollutants for the new Desert Sun Power Plant. All emissions are tons per year.

Pollutant		Combined Cycle CT1	Combined Cycle CT2	Auxiliary Boiler	Natural Gas Heater	Cooling Tower 1	Cooling Tower 2	Fire Pump	SF_6 Circuit Breakers	Nat. Gas Piping Systems	Total Project
Carbon Monoxide	CO	159.9	159.9	1.8	7.9			0.3			329.7
Nitrogen Oxides	NO_x	161.2	161.2	1.7	2.2			0.3			326.6
Particulate Matter	PM	79.2	79.2	0.3	1.50	0.088	0.088	0.02			160.4
Particulate Matter	PM_{10}	79.2	79.2	0.2	0.99	0.062	0.062	0.02			159.8
Particulate Matter	$PM_{2.5}$	79.2	79.2	0.2	0.99	0.0002	0.0002	0.02			159.6
Sulfur Dioxide	SO_2	10.4	10.4	0.0	0.12			0.00			21.0
Vol. Org. Cmpds	VOC	52.2	52.2	0.2	1.08			0.34			106.0
Sulfuric Acid Mist	H_2SO_4	3.1	3.1	0.0	0.012			0.000			6.3
Fluorides (F)	F	0.000	0.000	0.0	0.0000			0.0157			0.016
Lead	Pb	0.009	0.009	0.0	0.00010			0.000004			0.018
Carbon Dioxide	CO_2	2,034,354	2,034,354	5,264	23,056			68.5			4,097,097
Greenhouse Gases	CO_2e	2,036,444	2,036,444	5,269	23,080			68.8	727	1,481	4,103,514

Chapter 4. Hazardous Air Pollutant (HAP) Emissions Analysis.

4.1 Combustion Turbine Units CT1 and CT2.

For all periods of operation, including both normal operation and periods of startup and shutdown, the emission factors for all HAP emissions ***except formaldehyde*** are based on ***uncontrolled*** emission factors from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42*, Volume 1: Stationary Point and Area Sources, Section 3.1, Stationary Gas Turbines for Electricity Generation, Table 3.1-3.

4.1.1 Formaldehyde Emissions.

Based on this emissions analysis, the Desert Sun Power Plant will be a major source of HAPs. The *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*, 40 CFR 63 Subpart YYYY apply to new and existing CTs located at a major source of HAPs. In accordance with 40 CFR § 63.6090(a)(2), a stationary CT is new if you commenced construction of the stationary CT after January 14, 2003. And in accordance with Table 1 of Subpart YYYY, new lean premix gas-fired CTs must limit formaldehyde (CH_2O) to 91 parts per billion on a dry, volume basis (ppbdv) or less at 15% O_2, except during startup. This concentration may be converted to lb/mmBtu based on the following equation:

$$E = \frac{20.9KC_hF}{20.9 - \%O_2}$$

Where, E = Pollutant emission rate, lb/mmBtu
K_{CH2O} = 8.36×10^{-8} lb CH_2O/scf-ppm CH_2O
C_h = Pollutant concentration, ppmdv
F = Fuel-based Factor = 8,710 dscf/mmBtu

Substituting these values into the above equation, formaldehyde emissions of 91 ppbdv (0.091 ppmdv) at 15% O_2 is equal to an emission rate of 0.000235 lb/mmBtu:

$$E = \frac{20.9KC_hF}{20.9 - \%O_2} = \frac{20.9\left(8.36 \times 10^{-8}\ \frac{\text{lb CH}_2\text{O}}{\text{scf} \cdot \text{ ppm CH}_2\text{O}}\right)(0.091\ \text{ppm})(8{,}710\ \text{dscf/mmBtu})}{20.9 - 15}$$

$$E = 0.000235\ \text{lb/mmBtu}$$

The value of K_{CH2O}, in units of lb CH_2O/scf-ppm CH_2O, may be derived from the Ideal Gas Law at standard conditions (1.0 atmosphere and 32 °F) as follows:

$PV = nRT$ (Ideal Gas Law)

Where, P = Absolute Pressure, atmospheres R = Ideal Gas Law Constant, 0.73024 atm-ft^3/lb-mole-˚R
V = Volume, cubic feet (ft^3) T = Absolute Temperature, ˚R
n = Moles of Gas, lb-moles

The value of K may be calculated for formaldehyde, molecular weight 30.026 lb/lb-mole, by rearranging the Ideal Gas Law and using the molecular weight (MW) of formaldehyde:

$$\frac{(n)(MW)}{V} = \frac{(P)(MW)}{RT} = \frac{(1.0\ \text{atm})\left(30.026 \frac{\text{lb CH}_2\text{O}}{\text{lbmole CH}_2\text{O}}\right)}{\left(0.73024\ \frac{\text{atm} \cdot \text{ft}^3}{\text{lbmole} \cdot {}^\circ\text{R}}\right)(459.67 + 32\ {}^\circ\text{R})} = 0.0836\ \frac{\text{lb CH}_2\text{O}}{\text{ft}^3\ \text{CH}_2\text{O}}$$

The value of K is expressed in pounds of CH_2O per standard cubic foot ***per ppm of*** $\boldsymbol{CH_2O}$. Therefore, the value of K, expressed per ppm, is:

$$K_{CH2O} = 0.0836\ \frac{\text{lb CH}_2\text{O}}{\text{ft}^3\ \text{CH}_2\text{O}} \times \frac{1.0\ \text{ft}^3\ \text{CH}_2\text{O}}{1{,}000{,}000\ \text{ppm CH}_2\text{O}} = 8.36 \times 10^{-8}\ \frac{\text{lb CH}_2\text{O}}{\text{scf} \cdot\ \text{ppm CH}_2\text{O}}$$

This limit does not apply during periods of startup. Under 40 CFR § 63.6175, *Startup* begins at the first firing of fuel in the stationary combustion turbine. For simple cycle turbines, startup ends when the stationary combustion turbine has reached stable operation or after 1 hour, whichever is less. As a conservative estimate of startup and shutdown emissions, the all loads, uncontrolled emission factor for natural gas-fired CTs of 0.000312 lb/mmBtu was used from the U.S. EPA's document *EMISSION FACTOR DOCUMENTATION FOR AP-42 SECTION 3.1 STATIONARY GAS TURBINES,* April 2000, Table 3.4-1.

Table 4-1 is a summary of the potential HAP emissions for each new combined cycle CT. The startup and shutdown heat input is based on the number of startup and shutdown events proposed in this application and the maximum expected startup/shutdown heat input for these events.

TABLE 4-1. Potential hazardous air pollutant (HAP) emissions for each new combined cycle CT.

POLLUTANT	CAS No.	Normal Operation					Startup and Shutdown Operation					Total Potential to Emit
		Emission Factor	Heat Input		Potential Emissions		Emission Factor	Operating Rates		Potential Emissions		
		lb/mmBtu	mmBtu/hr	mmBtu/yr	lb/hour	ton/yr	lb/mmBtu	mmBtu	SUSD/yr	lb/SUSD	ton/yr	ton/yr
Acetaldehyde	75-07-0	0.000040	4,750	34,782,400	0.190	0.70	0.000040	2,070	366	0.083	0.015	0.71
Acrolein	107-02-8	0.000006	4,750	34,782,400	0.030	0.11	0.000006	2,070	366	0.013	0.002	0.11
Benzene	71-43-2	0.000012	4,750	34,782,400	0.057	0.21	0.000012	2,070	366	0.025	0.005	0.21
1,3-Butadiene	106-99-0	0.0000004	4,750	34,782,400	0.002	0.01	0.000000	2,070	366	0.001	0.000	0.01
Ethylbenzene	100-41-4	0.000032	4,750	34,782,400	0.152	0.56	0.000032	2,070	366	0.066	0.012	0.57
Formaldehyde	50-00-0	0.000235	4,750	34,782,400	1.116	4.09	0.003120	2,070	366	6.458	1.182	5.27
Hexane	110-54-3	0.000259	4,750	34,782,400	1.231	4.51	0.000259	2,070	366	0.537	0.098	4.61
Xylene	1330-20-7	0.000064	4,750	34,782,400	0.304	1.11	0.000064	2,070	366	0.132	0.024	1.14
Naphthalene	91-20-3	0.000001	4,750	34,782,400	0.006	0.02	0.000001	2,070	366	0.003	0.000	0.02
PAH		0.000002	4,750	34,782,400	0.010	0.04	0.000002	2,070	366	0.005	0.001	0.04
Propylene oxide	75-56-9	0.000029	4,750	34,782,400	0.138	0.50	0.000029	2,070	366	0.060	0.011	0.52
Toluene	108-88-3	0.000130	4,750	34,782,400	0.618	2.26	0.000130	2,070	366	0.269	0.049	2.31
TOTAL		**0.000812**	**4,750**	**34,782,400**	**3.85**	**14.1**	**0.003697**	**2,070**	**366**	**7.65**	**1.4**	**15.5**

Footnotes

1. The annual heat input during normal operation is equal to 6,760 hours per year at a heat input of 3,740 mmBtu/hr (equal to 25,282,400 mmBtu/yr), and 2,000 hours per year at 4,750 mmBtu/hr (equal to 9,500,000 mmBtu/yr), or a total of 34,782,400 mmBtu per year.
2. The emission factors for all HAPs and all periods of operation ***except formaldehyde emissions*** are *uncontrolled* emission factors from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42*, Volume 1: Stationary Point and Area Sources, Section 3.1, Stationary Gas Turbines for Electricity Generation.
3. Formaldehyde (CH_2O) emissions during normal operation are based on the emission limit of 91 parts per billion (ppbdv) or less at 15% O_2 for lean premix and diffusion-flame natural gas and oil-fired CTs located at major sources of HAPs in accordance with the *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*, 40 CFR 63, Subpart YYYY.
4. During periods of startup and shutdown, formaldehyde emissions are based on the all loads, uncontrolled emission factor for natural gas-fired CTs of 0.000312 lb/mmBtu was used from the U.S. EPA's document *EMISSION FACTOR DOCUMENTATION FOR AP-42 SECTION 3.1 STATIONARY GAS TURBINES*, April 2000, Table 3.4-1.

4.2 Auxiliary Boiler.

Potential HAP emissions for the natural gas-fired auxiliary boiler based on the proposed heat input limit equivalent to an annual capacity factor of 10% are included in Table 4-3. The emission factors in Table 4-2 are for natural gas-fired boilers from the U.S. EPA's AP-42, *Compilation of Air Pollutant Emission Factors*, 5th Edition, Natural Gas Combustion, Tables 1.4-3 and 1.4-4. The emission factors were converted from lb per million cubic feet of natural gas to pounds per million Btu based on a natural gas heat content of 1,000 Btu per cubic foot of gas.

TABLE 4-2. Potential HAP emissions for the natural gas-fired auxiliary boiler.

Pollutant	CAS No.	Emission Factor		Heat Input Rate		Potential to Emit	
		lb / 10^6 scf	lb / mmBtu	mmBtu / hr	mmBtu / year	lb/hr	ton/yr
Arsenic	7440-38-2	2.0E-04	2.0E-07	90	90,000	0.0000	0.0000
Barium	7440-39-3	4.4E-03	4.4E-06	90	90,000	0.0004	0.0002
Benzene	71-43-2	2.1E-03	2.1E-06	90	90,000	0.0002	0.0001
Cadmium	7440-43-9	1.1E-03	1.1E-06	90	90,000	0.0001	0.0000
Chromium	7440-47-3	1.4E-03	1.4E-06	90	90,000	0.0001	0.0001
Cobalt	7440-48-4	8.4E-05	8.4E-08	90	90,000	0.0000	0.0000
Copper	7440-50-8	8.5E-04	8.5E-07	90	90,000	0.0001	0.0000
Dichlorobenzene	25321-22-6	1.2E-03	1.2E-06	90	90,000	0.0001	0.0001
Formaldehyde	50-00-0	7.5E-02	7.5E-05	90	90,000	0.0068	0.0034
Hexane	110-54-3	1.8E+00	1.8E-03	90	90,000	0.1620	0.0810
Hydrogen Chloride	7647-01-0		1.2E-05	90	90,000	0.0011	0.0006
Manganese	7439-96-5	3.8E-04	3.8E-07	90	90,000	0.0000	0.0000
Mercury	7439-97-6	2.6E-04	2.6E-07	90	90,000	0.0000	0.0000
Molybdenum	7439-98-7	1.1E-03	1.1E-06	90	90,000	0.0001	0.0000
Naphthalene	91-20-3	6.1E-04	6.1E-07	90	90,000	0.0001	0.0000
Nickel	7440-02-0	2.1E-03	2.1E-06	90	90,000	0.0002	0.0001
Toluene	108-88-3	3.4E-03	3.4E-06	90	90,000	0.0003	0.0002
Vanadium	7440-62-2	2.3E-03	2.3E-06	90	90,000	0.0002	0.0001
TOTAL			**1.9E-03**	**90**	**90,000**	**0.17**	**0.09**

4.3 Natural Gas-Fired Natural Gas Heater.

Potential HAP emissions for the natural gas-fired natural gas dew point heater based on 8,760 hours per year of continuous operation are included in Table 4-3. The emission factors are for natural gas-fired boilers from the U.S. EPA's AP-42, *Compilation of Air Pollutant Emission Factors*, 5th Edition, Natural Gas Combustion, Tables 1.4-3 and 1.4-4. The emission factors were converted from lb per million cubic feet of natural gas to pounds per million Btu based on a natural gas heat content of 1,000 Btu per cubic foot of gas.

TABLE 4-3. Potential HAP emissions for the natural gas-fired natural gas heater.

Pollutant	CAS No.	Emission Factor		Heat Input Rate		Potential to Emit	
		lb / 10^6 scf	lb / mmBtu	mmBtu / hr	mmBtu / year	lb/hr	ton/yr
Arsenic	7440-38-2	2.0E-04	2.0E-07	45	394,200	0.00001	0.00004
Barium	7440-39-3	4.4E-03	4.4E-06	45	394,200	0.00020	0.00087
Benzene	71-43-2	2.1E-03	2.1E-06	45	394,200	0.00009	0.00041
Cadmium	7440-43-9	1.1E-03	1.1E-06	45	394,200	0.00005	0.00022
Chromium	7440-47-3	1.4E-03	1.4E-06	45	394,200	0.00006	0.00028
Cobalt	7440-48-4	8.4E-05	8.4E-08	45	394,200	0.00000	0.00002
Copper	7440-50-8	8.5E-04	8.5E-07	45	394,200	0.00004	0.00017
Dichlorobenzene	25321-22-6	1.2E-03	1.2E-06	45	394,200	0.00005	0.00024
Formaldehyde	50-00-0	7.5E-02	7.5E-05	45	394,200	0.00338	0.01478
Hexane	110-54-3	1.8E+00	1.8E-03	45	394,200	0.08100	0.35478
Hydrogen Chloride	7647-01-0		1.2E-05	45	394,200	0.00056	0.00244
Manganese	7439-96-5	3.8E-04	3.8E-07	45	394,200	0.00002	0.00007
Mercury	7439-97-6	2.6E-04	2.6E-07	45	394,200	0.00001	0.00005
Molybdenum	7439-98-7	1.1E-03	1.1E-06	45	394,200	0.00005	0.00022
Naphthalene	91-20-3	6.1E-04	6.1E-07	45	394,200	0.00003	0.00012
Nickel	7440-02-0	2.1E-03	2.1E-06	45	394,200	0.00009	0.00041
Toluene	108-88-3	3.4E-03	3.4E-06	45	394,200	0.00015	0.00067
Vanadium	7440-62-2	2.3E-03	2.3E-06	45	394,200	0.00010	0.00045
TOTAL			**1.9E-03**	**45**	**394,200**	**0.086**	**0.38**

4.4 Diesel Engine Emergency Fire Pump.

Potential HAP emissions for the diesel engine-driven fire pump based on an operating limit of 200 hours per year are included in Table 4-4. Hazardous air pollutant emission factors are from the U.S. EPA's *Compilation of Air Pollutant Emission Factors*, AP-42, 5th Edition, Tables 3.4-3 and 3.4-4.

TABLE 4-4. Potential HAP emissions for the diesel engine-driven fire pump based on an operating limit of 200 hours per year.

AIR POLLUTANT	CAS #	Emission Factor[1]	Heat Input	Potential to Emit	
		lb/mmBtu	mmBtu/hr	lb/hr	ton/yr
Benzene	71-43-2	7.76E-04	4.20	0.00326	0.00033
Toluene	108-88-3	2.81E-04	4.20	0.00118	0.00012
Xylene	1330-20-7	1.93E-04	4.20	0.00081	0.00008
Formaldehyde	50-00-0	7.89E-05	4.20	0.00033	0.00003
Acetaldehyde	75-07-0	2.52E-05	4.20	0.00011	0.00001
Acrolein	107-02-8	7.88E-06	4.20	0.00003	0.00000
Naphthalene	91-20-3	1.30E-04	4.20	0.00055	0.00005
Total PAH		2.12E-04	4.20	0.00089	0.00009
TOTAL					**0.0007**

Footnotes

1. Hazardous air pollutant emission factors are from the U.S. EPA's *Compilation of Air Pollutant Emission Factors*, AP-42, 5th Edition, Tables 3.4-3 and 3.4-4.

2. Potential emissions are based on limiting the total annual operation to less than 200 hours per year.

3. The maximum heat input rate is based on 30 gallons of fuel oil per hour, and a fuel oil heat value of 140,000 Btu per gallon.

4.5 Total Potential Hazardous Air Pollutant Emissions for the Desert Sun Power Plant.

Table 4-5 summarizes the total potential HAP emissions for the entire Desert Sun Power Plant based on the proposed emission and operating limits in this application.

TABLE 4-5. Total potential hazardous air pollutant (HAP) emissions for the Desert Sun Power Plant, tons per year.

Pollutant	CAS No.	Combined Cycle CT1	Combined Cycle CT2	Auxiliary Boiler	Natural Gas Heater	Two Cooling Towers	Fire Pump	SF_6 Circuit Breakers	Nat. Gas Piping Systems	Total Project
Acetaldehyde	75-07-0	0.71	0.71				0.00001			1.42
Acrolein	107-02-8	0.11	0.11				0.00000			0.23
Benzene	71-43-2	0.21	0.21	0.00009	0.00041		0.00033			0.43
1,3-Butadiene	106-99-0	0.01	0.01							0.02
Dichlorobenzene	25321-22-6			0.00005	0.00024					0.00
Ethylbenzene	100-41-4	0.57	0.57							1.14
Formaldehyde	50-00-0	5.27	5.27	0.00338	0.01478		0.00003			10.56
Hexane	110-54-3	4.61	4.61	0.08100	0.35478					9.65
Xylene	1330-20-7	1.14	1.14				0.00008			2.27
Naphthalene	91-20-3	0.02	0.02	0.00003	0.00012		0.00005			0.05
PAH		0.04	0.04				0.00009			0.08
Propylene oxide	75-56-9	0.52	0.52							1.03
Toluene	108-88-3	2.31	2.31	0.00015	0.00067		0.00012			4.62
Arsenic	7440-38-2			0.00001	0.00004					0.00
Barium	7440-39-3			0.00020	0.00087					0.00
Cadmium	7440-43-9			0.00005	0.00022					0.00
Chromium	7440-47-3			0.00006	0.00028					0.00
Cobalt	7440-48-4			0.00000	0.00002					0.00
Copper	7440-50-8			0.00004	0.00017					0.00
Manganese	7439-96-5			0.00002	0.00007					0.00
Mercury	7439-97-6			0.00001	0.00005					0.00
Molybdenum	7439-98-7			0.00005	0.00022					0.00
Nickel	7440-02-0			0.00009	0.00041					0.00
Vanadium	7440-62-2			0.00010	0.00045					0.00
Hydrogen Chloride	7647-01-0			0.00056	0.00244					0.00
All HAPs Combined		**15.5**	**15.5**	**0.1**	**0.4**	**0.0**	**0.001**	**0.0**	**0.0**	**31.5**

Chapter 5. Applicable Requirements.

5.1 Applicable Requirements for the New Stationary Source.

5.1.1 Major New Source Review (NSR) Air Permitting Requirements.

In the Clean Air Act Amendments of 1977, Congress established two preconstruction permitting programs which are referred to as New Source Review (NSR). Title I, Part C of the Act includes the PREVENTION OF SIGNIFICANT DETERIORATION OF AIR QUALITY (PSD) program. The PSD program is codified under the Code of Federal Regulations, 40 CFR §52.21 and Maricopa County Rule 240, Section 305. The PSD program applies to new major sources or major modifications at existing sources for pollutants where the area is in attainment with National Ambient Air Quality Standards (NAAQS). The PSD program requires:

1. Best Available Control Technology (BACT) for pollutants exceeding the significant levels.
2. An air quality analysis demonstrating that new emissions will not cause or contribute to a violation of any applicable NAAQS or PSD increment.
3. An additional impacts analysis.
4. Public involvement and participation.

Title I, Part D of the Clean Air Act includes the PLAN REQUIREMENTS FOR NONATTAINMENT AREAS. This program is called the Non-Attainment Area New Source Review (NANSR) program, and is codified in Maricopa County Rule 240, Section 304 which incorporates the requirements of 40 CFR §51.165(a)(1). NANSR applies to new major sources or major modifications at existing sources for pollutants where the area is not in attainment with the NAAQS. All NANSR programs require:

1. Lowest Achievable Emission Rate (LAER) for pollutants exceeding the NANSR significant levels.
2. Emission offsets.
3. Alternatives Analysis
4. Public involvement and participation.

As shown in Figure 2-1, the proposed location for the Desert Sun Power Plant in Maricopa County is classified as attainment or unclassified for all criteria air pollutants. Therefore, the Desert Sun Power Plant is subject to review under the PSD program in County Rule 240, Section 305, but is not subject to the NANSR program in County Rule 240, Section 304. The PSD program requires that a new major stationary source or a major modification of an existing major stationary source within an attainment area must undergo PSD review and obtain a construction permit prior to commencing construction.

Table 5-1 is a summary of the potential PSD regulated pollutant emissions based on the proposed emissions and operating limits in this application. From Table 5-1, the Desert Sun Power Plant will result in significant emissions increase and a significant net emissions increase of CO, NO_x, PM, PM_{10}, $PM_{2.5}$, VOC, and greenhouse gas (GHG) emissions. Therefore, this Project is subject to PSD review for these pollutants and will require the application of BACT for each of these pollutants.

TABLE 5-1. Potential emissions for the proposed Desert Sun Power Plant and PSD applicability. All emissions are tons per year.

Pollutant		Total Project Potential to Emit	PSD Significant Threshold	OVER?
Carbon Monoxide	CO	329.7	100	**YES**
Nitrogen Oxides	NO_x	326.6	40	**YES**
Particulate Matter	PM	160.4	25	**YES**
Particulate Matter	PM_{10}	159.8	15	**YES**
Particulate Matter	$PM_{2.5}$	159.6	10	**YES**
Sulfur Dioxide	SO_2	21.0	40	**NO**
Volatile Organic Compounds	VOC	106.0	40	**YES**
Sulfuric Acid Mist	H_2SO_4	6.3	7	**NO**
Fluorides (F)	F	0.016	3	**NO**
Lead	Pb	0.018	0.6	**NO**
Carbon Dioxide	CO_2	4,097,097	n/a	**n/a**
Greenhouse Gases	CO_2e	4,103,514	75,000	**YES**

5.1.2 Minor New Source Review (NSR) Air Permitting Requirements.

In accordance with County Rule 241 §102.2, minor new source (NSR) review permitting requirements are applicable to a modification that would increase the source's potential to emit equal to or greater than the minor NSR modification thresholds. The minor NSR program requires the application of the Best Available Control Technology (BACT) or Reasonably Available Control Technology (RACT), as required by Rule 241, Sections 304 or 305, for each new emissions unit. The proposed Project's potential to emit, the minor NSR BACT threshold levels, and the minor NSR applicability are summarized in Table 5-2. From Table 5-2, this Project will exceed the minor NSR BACT thresholds for CO, NO_x, PM_{10}, $PM_{2.5}$, SO_2, and VOC emissions. However, in accordance with Rule 241, Section 103, the provisions of this rule shall not apply if the emissions are subject to major source requirements under Rule 240. Because this Project will be subject to Rule 240 for these pollutants, this project is not subject to review under the minor NSR program.

TABLE 5-2. Total new stationary source potential emissions, the minor NSR threshold levels under Rule 241, and minor NSR applicability. All emissions are tons per year.

Pollutant		Potential to Emit	Minor NSR Threshold	OVER?	Minor NSR BACT	OVER?
Carbon Monoxide	CO	329.7	50	**YES**	100	**YES**
Nitrogen Oxides	NO_x	326.6	20	**YES**	40	**YES**
Particulate Matter	PM_{10}	159.8	7.5	**YES**	15	**YES**
Particulate Matter	$PM_{2.5}$	159.6	5	**YES**	10	**YES**
Sulfur Dioxide	SO_2	21.0	20	**YES**	40	**NO**
Volatile Organic Compounds	VOC	106.0	20	**YES**	40	**YES**

5.2 Combustion Turbine Units CT1 and CT2.

5.2.1 40 CFR 60 Subpart KKKKa.

On January 9, 2026, the U.S. Environmental Protection Agency (U.S. EPA) finalized amendments to the *Standards of Performance for Stationary Combustion Turbines*, 40 CFR 60, Subpart KKKKa. These amendments set standards of performance for emissions of nitrogen oxide (NO_x) and sulfur dioxide (SO_2) from stationary CTs. The applicability requirements in 40 CFR § 60.4305a state:

> **§ 60.4305a Does this subpart apply to my stationary combustion turbine?**
>
> (a) Except as provided for in § 60.4310a, you are subject to this subpart if you own or operate a stationary combustion turbine that commenced construction, modification, or reconstruction after December 13, 2024, and that has a base load rating equal to or greater than 10.7 gigajoules per hour (GJ/h) (10 million British thermal units per hour (MMBtu/h)). Any additional heat input from duct burners used with heat recovery steam generating (HRSG) units or fuel preheaters is not included in the heat input value used to determine the applicability of this subpart to a given stationary combustion turbine. However, this subpart does apply to emissions from any associated HRSG and duct burner(s) that are associated with a combustion turbine subject to this subpart.
>
> (b) A stationary combustion turbine subject to this subpart is not subject to subpart GG or subpart KKKK of this part.

5.2.1.1 Nitrogen Oxides (NO_x) Emissions.

For the combined cycle CTs which are categorized as large CTs with a base-load heat input greater than 850 mmBtu per hour and a utilization rate of more than 45%, the EPA set input based emission standards for loads less than and greater than 70% of the base load rating which are based on a 4-operating-hour rolling average basis, and an optional output based emission standard which is based on a 30-operating-day average basis. These standards are **highlighted in green** in Table 1 of Subpart KKKKa below.

In accordance with 40 CFR § 60.4350a(h), “Hours are not subcategorized by load for the purposes of determining the applicable output-based standard. The emissions standard for all hours, regardless of load, is the otherwise applicable full load emissions standard.” For these combined cycle CTs, the output based performance standard is therefore 0.12 lb/MWh-gross for ALL hours of operation.

For compliance with the input based standards, 40 CFR § 60.4350a(g), states:

> (g) For each stationary combustion turbine demonstrating compliance on a heat input-based emissions standard, excess NOx emissions are determined on a 4-operating-hour averaging period basis using the NOx CEMS data and procedures specified in paragraphs (g)(1) and (2) of this section as applicable to the NOx emissions standard in table 1 to this subpart.
>
> (1) For each 4-operating-hour period, compute the 4-operating-hour rolling average NOx emissions as the heat input weighted average of the hourly average of NOx emissions for a given operating hour and the 3 operating hours preceding that operating hour using the applicable equation in paragraph (g)(2) of this section. Calculate a 4-operating-hour rolling average NOx emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3

of those hours (e.g., a valid 4-operating-hour rolling average NOx emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period).

(2) If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the 4-operating-hour rolling average NOx emissions rate and the applicable 4-operating-hour rolling average NOx emissions standard, calculated using hourly values in table 1 to this subpart, using equation 4 to this section.

Therefore, when demonstrating compliance with the heat input-based standard, you must calculate the heat input weighted actual emission rate AND the heat input weighted emission limit. In other words, both the actual emission rate and the emission limit are calculated for each hour of operation based on whether the CT was operating above or below 70% of the base load rating.

Excerpts from Table 1 to Subpart KKKKa of Part 60 - Nitrogen Oxide Emission Standards for Stationary Combustion Turbines

Combustion Turbine Type	Combustion Turbine Base Load Rated Heat Input (HHV)	Input-Based NO_x Emission Standard[1]	Optional Output-Based NO_x Standard[2]
New, firing natural gas with utilization rate > 45 percent	**> 850 MMBtu/h**	**5 ppm at 15 percent O_2 or 7.9 ng/J (0.018 lb/MMBtu)**	**0.054 kg/MWh-gross (0.12 lb/MWh-gross) 0.055 kg/MWh-net (0.12 lb/MWh-net)**
New, firing natural gas with utilization rate ≤ 45 percent and with design efficiency ≥ 38 percent	> 850 MMBtu/h	25 ppm at 15 percent O_2 or 40 ng/J (0.092 lb/MMBtu)	0.38 kg/MWh-gross (0.83 lb/MWh-gross) 0.39 kg/MWh-net (0.85 lb/MWh-net)
New, firing natural gas with utilization rate ≤ 45 percent and with design efficiency < 38 percent	> 850 MMBtu/h	9 ppm at 15 percent O_2 or 14 ng/J (0.033 lb/MMBtu)	0.17 kg/MWh-gross (0.37 lb/MWh-gross) 0.17 kg/MWh-net (0.38 lb/MWh-net)
Located north of the Arctic Circle (latitude 66.5 degrees north), operating at ambient temperatures less than 0°F (-18°C), modified or re-constructed offshore turbines, operated during periods of turbine tuning, byproduct-fired turbines, and/or operating at less than 70 percent of the base load rating	**> 300 MMBtu/h**	**96 ppm at 15 percent O_2 or 150 ng/J (0.35 lb/MMBtu)**	**N/A**

[1] *Input-based standards are determined on a 4-operating-hour rolling average basis.*
[2] *Output-based standards are determined on a 30-operating-day average basis.*

5.2.1.2 Sulfur Dioxide (SO_2) Emissions.

The applicable new SO_2 emission standards under Subpart KKKKa for all of the proposed CTs, including both the simple cycle and combined cycle units are the same as the standards under Subpart KKKK:

> **§ 60.4330a What SO_2 emissions standard must I meet?**
>
> **(a**) Except as provided for in paragraphs (b) through (e) of this section, for each new, modified, or reconstructed stationary combustion turbine you must not cause to be discharged from the affected facility and into the atmosphere any gases that
>
> contain an amount of SO_2 exceeding either:
>
> (1) 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross energy output; or
>
> (2) 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

The applicable limits are 0.90 pounds of SO_2 per megawatt-hour of gross output or 0.060 lb SO_2/mmBtu heat input. The combustion of pipeline natural gas will meet this emission standard.

5.2.2 Acid Rain Program.

In accordance with the applicability requirements of the Acid Rain Program in 40 CFR § 72.6(a)(3)(i), a *utility unit* that is a *new unit* shall be an affected unit:

> **§ 72.6 Applicability.**
>
> (a) Each of the following units shall be an affected unit, and any source that includes such a unit shall be an affected source, subject to the requirements of the Acid Rain Program:
>
> (1) A unit listed in table 1 of § 73.10(a) of this chapter.
>
> (2) A unit that is listed in table 2 or 3 of § 73.10 of this chapter and any other existing utility unit, except a unit under paragraph (b) of this section.
>
> (3) A utility unit, except a unit under paragraph (b) of this section, that:
>
> (i) Is a new unit;

Under 40 CFR § 72.2, "utility unit" and "new unit" mean:

> *Utility unit means a unit owned or operated by a utility:*
> *(1) That serves a generator in any State that produces electricity for sale, or*
> *(2) That during 1985, served a generator in any State that produced electricity for sale.*
> *New unit* means a unit that commences commercial operation on or after November 15, 1990, including any such unit that serves a generator with a nameplate capacity of 25 MWe or less or that is a simple combustion turbine.

Since these CTs would produce electricity for sale, they are "utility units." The definition of "new unit" includes a unit that commences commercial operation on or after November 15, 1990, including a simple combustion turbine. "Simple combustion turbines" and "Unit" are subsequently defined as:

> *Simple combustion turbine* means a unit that is a rotary engine driven by a gas under pressure that is created by the combustion of any fuel. This term includes combined cycle units without auxiliary firing. This term excludes combined cycle units with auxiliary firing, unless the unit did not use the auxiliary firing from 1985 through 1987 and does not use auxiliary firing at any time after November 15, 1990.
>
> *Unit* means a fossil fuel-fired combustion device.

Based on these requirements, these new combined cycle CTs will be fossil fuel-fired combustion devices that commenced commercial operation on or after November 15, 1990. These new CTs will also be utility units. Therefore, these CTs will be affected units under the Acid Rain Program. APS will submit an Acid Rain Permit application to EPA and provide a copy to Maricopa County Air Quality Department (MCAQD).

5.2.3 National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines 40 CFR Part 63, Subpart YYYY.

The *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines*, 40 CFR Part 63, Subpart YYYY apply to new and existing combustion sources located at a major source of hazardous air pollutants (HAPs). Based on the emissions analysis in Chapter 4, the Desert Sun Power Plant will be a major source of HAPs. In accordance with 40 CFR § 63.6090(a)(2), a stationary combustion turbine is new if you commenced construction of the stationary combustion turbine after January 14, 2003.

5.2.3.1 Emission Limit.

In accordance with Table 1 of Subpart YYYY, new, lean premix gas-fired stationary combustion turbines must limit the concentration of formaldehyde (CH_2O) to 91 parts per billion on a dry, volume basis (ppbdv) or less at 15% O_2, except during turbine startup. The period of time for turbine startup is subject to the limits specified in the definition of startup in § 63.6175. This emission rate concentration may be converted to lb/mmBtu based on the following equation:

$$E = \frac{20.9KC_hF}{20.9 - \%O_2}$$

Where, E = Pollutant emission rate, lb/mmBtu

K_{CH2O} = 8.36×10^{-8} lb CH_2O/scf-ppm CH_2O

C_h = Pollutant concentration, ppmdv

F = Fuel-based Factor = 8,710 dscf/mmBtu

The value of K, in units of lb CH_2O/scf-ppm CH_2O, may be derived from the Ideal Gas Law at standard conditions (1.0 atmosphere and 32 °F) as follows:

$$PV = nRT \quad \text{(Ideal Gas Law)}$$

Where, P = Absolute Pressure, atmospheres
V = Volume, cubic feet (ft^3)
R = Ideal Gas Law Constant, 0.73024 atm-ft^3/lb-mole-˚R
T = Absolute Temperature, ˚R
n = Moles of Gas, lb-moles

The value of K may be calculated for formaldehyde, molecular weight 30.026 lb/lb-mole, by rearranging the Ideal Gas Law and using the molecular weight (MW) of formaldehyde:

$$PV = nRT \quad \leftrightarrow \quad \frac{n}{V} = \frac{P}{RT} \quad \leftrightarrow \quad \frac{(n)(MW)}{V} = \frac{(P)(MW)}{RT}$$

$$\frac{(n)(MW)}{V} = \frac{(P)(MW)}{RT} = \frac{(1.0\ \text{atm})\left(30.026\,\frac{\text{lb CH}_2\text{O}}{\text{lb}-\text{mole CH}_2\text{O}}\right)}{\left(0.73024\ \frac{\text{atm}\cdot\text{ft}^3}{\text{lb}-\text{mole}\cdot{}^\circ\text{R}}\right)(459.67+32\ {}^\circ\text{R})} = 0.0836\ \frac{\text{lb CH}_2\text{O}}{\text{ft}^3\ \text{CH}_2\text{O}}$$

The value of K is expressed in pounds of CH_2O per standard cubic foot **per ppm of CH_2O**. Therefore, the value of K, expressed per ppm, is:

$$K_{CH2O} = 0.0836\ \frac{\text{lb CH}_2\text{O}}{\text{ft}^3\ \text{CH}_2\text{O}} \times \frac{1.0\ \text{ft}^3\ \text{CH}_2\text{O}}{1{,}000{,}000\ \text{ppm CH}_2\text{O}} = 8.36\times10^{-8}\ \frac{\text{lb CH}_2\text{O}}{\text{scf}\cdot\ \text{ppm CH}_2\text{O}}$$

Substituting these values into the above equation, formaldehyde emissions of 91 ppbdv (0.091 ppmdv) at 15% O_2 is equal to an emission rate of 0.000235 lb/mmBtu:

$$E = \frac{20.9KC_hF}{20.9-\%O_2} = \frac{20.9\left(8.36\times10^{-8}\ \frac{\text{lb CH}_2\text{O}}{\text{scf}\cdot\ \text{ppm CH}_2\text{O}}\right)(0.091\ \text{ppm})(8{,}710\ \text{dscf/mmBtu})}{20.9-15}$$

$$E = 0.000235\ \text{lb/mmBtu}$$

This limit does not apply during periods of startup. Under 40 CFR § 63.6175, *Startup* begins at the first firing of fuel in the stationary combustion turbine. For simple cycle turbines, startup ends when the stationary combustion turbine has reached stable operation or after 1 hour, whichever is less.

5.2.3.2 Operating Limits.

The CTs will also be subject to the following operating limitations in Table 2 to Subpart YYYY. We Energies is not proposing to install oxidation catalyst control systems to comply with the Subpart YYYY emission limit. Therefore, the operating limitations would be in accordance with Subpart YYYY, Table 2, subparagraph 2.

Table 2 to Subpart YYYY of Part 63—Operating Limitations

As stated in §§ 63.6100 and 63.6140, you must comply with the following operating limitations.

For . . .	You must . . .
1. each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is using an oxidation catalyst	maintain the 4-hour rolling average of the catalyst inlet temperature within the range suggested by the catalyst manufacturer. You are not required to use the catalyst inlet temperature data that is recorded during engine startup in the calculations of the 4-hour rolling average catalyst inlet temperature.
2. each stationary combustion turbine that is required to comply with the emission limitation for formaldehyde and is not using an oxidation catalyst	maintain any operating limitations approved by the Administrator.

5.2.3.3 Performance Test Requirements.

In accordance with 40 CFR §63.6110(a), you must conduct an initial performance test or other initial compliance demonstrations in Table 4 of Subpart YYYY within 180 calendar days after startup of each CTG. Subsequent performance tests must be performed on an annual basis.

5.2.4 40 CFR 64 – Compliance Assurance Monitoring.

The Compliance Assurance Monitoring (CAM) program is codified in 40 CFR Part 64. CAM plan requirements apply to any pollutant specific emissions unit with:

1. Uncontrolled potential emissions above the major source threshold of 100 tons per year, and
2. Uses a control device to achieve compliance with an emission limitation or standard.

Pre-control device NO_x and CO emissions for these new CTs exceed this threshold. Note that PM, PM_{10}, and $PM_{2.5}$ emissions are not subject to CAM requirements because there is no control device used to achieve compliance with the PM emission limit. With respect to NO_x emissions, the new CTs will be subject to 40 CFR 60 Subpart KKKKa and are also affected units under the Acid Rain Program in 40 CFR Part 72 – 75. In accordance with the CAM applicability requirements in 40 CFR § 64.2(b)(1)(i) and (iii), the CAM plan requirements do not apply to the emission units and pollutants subject to these programs, or, for these CTs, NO_x emissions. There are no specific applicable requirements for CO emissions from these CTs under a New Source Performance Standard (NSPS) or under any National Emission Standard for Hazardous Air Pollutants (NESHAP). APS is proposing to use CEMS for monitoring CO and NO_x emissions from the proposed new CTs. Therefore, in accordance with 40 CFR § 64.2(b)(1)(vi), CAM plan requirements do not apply for NO_x and CO emissions from the proposed units.

5.2.5 Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units, 40 CFR 60 Subpart TTTTa.

On May 9, 2024, the U.S. EPA published a final rule establishing greenhouse gas standards and guidelines for new and reconstructed stationary combustion turbine electric generating units under 40 CFR 60, Subpart TTTTa. New stationary combustion turbines that commence construction or reconstruction after May 23, 2023 and meet the relevant applicability criteria will be subject to 40 CFR 60, subpart TTTTa.

For new and reconstructed fossil fuel-fired combustion turbines, the final rule creates three subcategories based on the function the combustion turbine serves. In accordance with 40 CFR § 60.5580a, *Base load combustion turbine* means "a stationary combustion turbine that supplies more than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis." These proposed CTs will be base load combustion turbines. The applicable emission limits for base load combustion turbines in Table 1 to Subpart TTTTa are included below.

Table 1 to Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After May 23, 2023 (Gross or Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[NOTE: NUMERICAL VALUES OF 1,000 OR GREATER HAVE A MINIMUM OF 3 SIGNIFICANT FIGURES AND NUMERICAL VALUES OF LESS THAN 1,000 HAVE A MINIMUM OF 2 SIGNIFICANT FIGURES]

Affected EGU category	CO_2 emission standard
Base load combustion turbines	For 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a. For 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.

On June 17, 2025, the U.S. EPA published a proposed rule to repeal all GHG emissions standards for fossil fuel-fired power plants. The EPA is proposing that the Clean Air Act (CAA) requires it to make a finding that GHG emissions from fossil fuel-fired power plants contribute significantly to dangerous air pollution, as a predicate to regulating GHG emissions from those plants. The EPA is further proposing to make a finding that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution. The EPA is also proposing, as an alternative, to repeal the emission standards under Subpart TTTTa that includes the emission guidelines for existing fossil fuel-fired steam generating units, the carbon capture and sequestration/storage (CCS)-based standards for coal-fired steam generating units undertaking a large modification, and the CCS-based standards for new base load stationary combustion turbines.

5.3 Auxiliary Boiler.

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

This boiler will be subject to the *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, 40 CFR 60 Subpart Dc. This subpart applies to steam generating units that have a maximum design heat input capacity of 100 million Btu per hour or less, but greater than or equal to 10 million Btu/hr. This subpart establishes emission standards for NO_x, PM, and SO_2 emissions from affected boilers. However, while this subpart requires initial notifications of the start of construction and initial startup, there are no applicable emission standards for affected boilers that fire only natural gas.

5.3.2 National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63 Subpart DDDDD.

The Desert Sun Power Plant will be a major source of hazardous air pollutants. Therefore, the auxiliary boiler (and also the natural gas heater) will be subject to the *Standards of Performance for Industrial – Commercial – Institutional Steam Generating Units* in 40 CFR 63 Subpart DDDDD. The auxiliary boiler will utilize only natural gas as fuel. In accordance with the definitions in 40 CFR §63.7575, "*Unit designed to burn gas 1 subcategory* includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels". As stated in 40 CFR §63.7500(e), boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to Subpart DDDDD, or the operating limits in Table 4. However, in accordance with the work practice standards in 40 CFR §63.7540(a)(10), if your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance. And in accordance with 40 CFR §63.7540(a)(12), if your boiler has a continuous oxygen trim system that maintains an optimum air to fuel ratio and the unit is in the units designed to burn gas 1, you must conduct a tune-up of the boiler or process heater every 5 years. The auxiliary boiler will have a continuous oxygen trim system. Therefore, Subpart DDDDD will require a tune-up of the boiler or every 5 years.

5.3.3 40 CFR 64 – Compliance Assurance Monitoring *(not applicable)*.

The Compliance Assurance Monitoring (CAM) program is codified in 40 CFR Part 64. CAM plan requirements apply to any pollutant specific emissions unit with:

1. Uncontrolled potential emissions above the major source threshold of 100 tons per year, and
2. Uses a control device to achieve compliance with an emission limitation or standard.

The auxiliary boiler will not have maximum potential uncontrolled emissions of any pollutant which will exceed the major source threshold of 100 tons per year. Therefore, this boiler is not subject to CAM requirements.

5.4 Natural Gas-Fired Natural Gas Heater.

5.4.1 Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60 Subpart Dc *(not applicable)*.

The natural gas-fired natural gas heater will have a maximum rated heat input capacity of 35.0 mmBtu per hour. The *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, 40 CFR 60 Subpart Dc apply to "each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989". In accordance with 40 CFR 60.41c, a *process heater* is a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst. This is precisely the function of this heater. Therefore, according to this definition, this natural gas heater is a process heater and is therefore not subject to Subpart Dc. In any case, even if this heater were subject to Subpart Dc, there would be no applicable requirements for this heater because it burns only natural gas.

5.4.2 National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR 63 Subpart DDDDD.

The Desert Sun Power Plant will be a major source of hazardous air pollutants. Therefore, the natural gas heater will be subject to the *Standards of Performance for Industrial – Commercial – Institutional Steam Generating Units* in 40 CFR 63 Subpart DDDDD. in accordance with the work practice standards in 40 CFR §63.7540(a)(10), if your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance. And in accordance with 40 CFR §63.7540(a)(12), if your boiler has a continuous oxygen trim system that maintains an optimum air to fuel ratio and the unit is in the units designed to burn gas 1, you must conduct a tune-up of the boiler or process heater every 5 years.

5.4.3 40 CFR 64 – Compliance Assurance Monitoring *(not applicable)*.

The Compliance Assurance Monitoring (CAM) program is codified in 40 CFR Part 64. CAM plan requirements apply to any pollutant specific emissions unit with:

1. Uncontrolled potential emissions above the major source threshold of 100 tons per year, and
2. Uses a control device to achieve compliance with an emission limitation or standard.

This natural gas-fired natural gas heater will not have maximum potential uncontrolled emissions of any pollutant which will exceed the major source threshold of 100 tons per year. Therefore, this heater is not subject to CAM requirements.

5.5 Diesel Engine Driven Emergency Fire Pump.

5.5.1 Standards of Performance for Stationary Compression Ignition Internal Combustion Engines under 40 CFR 60, Subpart IIII.

The Desert Sun Power Plant 510 horsepower diesel engine driven fire pump will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* under 40 CFR 60, Subpart IIII. These emission standards are summarized below.

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines], g/kWh (g/Hp-hr)

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +[3]	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)

5.5.2 40 CFR 64 – Compliance Assurance Monitoring *(not applicable)*.

The Compliance Assurance Monitoring (CAM) program is codified in 40 CFR Part 64. CAM plan requirements apply to any pollutant specific emissions unit with:

1. Uncontrolled potential emissions above the major source threshold of 100 tons per year, and
2. Uses a control device to achieve compliance with an emission limitation or standard.

The natural gas-fired natural gas heater will not have maximum potential uncontrolled emissions of any pollutant which will exceed the major source threshold of 100 tons per year. Therefore, this heater is not subject to CAM requirements.

Chapter 6. Proposed Emission Limits.

With this application, APS is proposing the following emission and operating limits for the emissions units included in this application. Please refer to Appendix C for details on the proposed BACT emission limits.

6.1 Combined Cycle Units CT1 and CT2.

6.1.1 Proposed BACT Emission Limits.

Pollutant	BACT Emission Limit	
	Normal Operation	**Startup and Shutdown Operation**
Carbon Monoxide (CO)	2.0 ppmdv at 15% O_2 based on a 3-hour average	1. The total number of cold startup events may not exceed 16 events in any consecutive 12-month period. 2. The total number of warm and hot startups events combined may not exceed 350 events in any consecutive 12-month period. 3. The total CO emissions may not exceed 159.9 tons per year, based on a 12-month average.
Nitrogen Oxides (NO_x)	2.0 ppmdv at 15% O_2 based on a 3-hour average	1. The total number of cold startup events may not exceed 16 events in any consecutive 12-month period. 2. The total number of warm and hot startups events combined may not exceed 350 events in any consecutive 12-month period. 3. The total NO_x emissions may not exceed 161.2 tons per year, based on a 12-month average.
Particulate Matter (PM, PM_{10}, and $PM_{2.5}$)	15.0 lb/hour without duct firing, based on a 3-hour average 28.5 lb/hour with duct firing, based on a 3-hour average	
Volatile Organic Compounds (VOC)	5.0 pounds per hour without duct firing, based on a 3-hour average 12.1 pounds per hour with duct firing, based on a 3-hour average	1. The total number of cold startup events may not exceed 16 events in any consecutive 12-month period. 2. The total number of warm and hot startups events combined may not exceed 350 events in any consecutive 12-month period. 3. The total VOC emissions may not exceed 52.2 tons per year, based on a 12-month average.

Pollutant	BACT Emission Limit	
	Normal Operation	Startup and Shutdown Operation
Greenhouse Gas (GHG) Emissions	800 lb CO_2 per megawatt-hour of gross electric output based on a 12-month average (890 lb CO_2 per megawatt-hour of gross electric output based on a 12-month average if Subpart TTTTa is repealed)	
Startup Shutdown Events	"Hot startup" is defined as taking place within 8 hours after the previous shutdown. A hot startup is the period beginning with the ignition of fuel and ending 30 minutes later. "Warm startup" is defined as taking place more than 8 hours but less than 72 hours after the previous shutdown. A warm startup is the period beginning with the ignition of fuel and ending 60 minutes later. "Cold startup" is defined as taking place more than 72 hours after the previous shutdown. A cold startup is the period beginning with the ignition of fuel and ending 70 minutes later. "Shutdown" is defined as the period beginning with the initiation of gas turbine shutdown sequence and lasting until fuel combustion has ceased.	

6.1.2 Other Proposed Emission and Operating Limits.

1. The total duct burner operation for each combined cycle unit may not exceed 2,000 hours in any consecutive 12-month period.

2. The maximum short-term emissions from each combustion turbine during normal operation, excluding periods of startup and shutdown, tuning/testing mode and equipment shakedown prior to commercial operation shall not exceed the following limits.

	CO[1]	NO_x[1]	PM, PM_{10}, and $PM_{2.5}$[2]
Emission Limit, lb/hour	21.1	34.6	28.5
Averaging Period	3-hour	3-hour	3-hour

Footnote 1: Compliance with the CO and NO_x emission limits are based on the use of NO_x and CO CEMS.

Footnote 2: Compliance with the PM, PM_{10}, and $PM_{2.5}$ emission limit is based on monitored fuel flow data and compliance emission testing using U.S. EPA Reference Methods 5 or 201or 201A for filterable PM plus Reference Method 202 for condensable PM.

3. The maximum short-term emissions from each combustion turbine during periods of startup, shutdown, tuning/testing, and equipment shakedown prior to commercial operation shall not exceed the following limits.

	CO[1]	NO_x[1]
Emission Limit, lb/hour	1,500	300
Averaging Period	1-hour	1-hour

Footnote 1: Compliance with the CO and NO_x emission limits are based on the use of NO_x and CO CEMS.

6.2 Natural Gas-Fired Auxiliary Boiler.

6.2.1 Proposed BACT Emission Limits.

Pollutant	BACT Emission Limit
Carbon Monoxide (CO)	0.04 lb/mmBtu based on a 3-hour average
Nitrogen Oxides (NO_x)	0.037 lb/mmBtu based on a 3-hour average
Particulate Matter (PM, PM_{10}, and $PM_{2.5}$)	The auxiliary boiler may only use natural gas as a fuel. 0.005 lb/mmBtu based on a 3-hour average
Volatile Organic Compounds (VOC)	0.0055 lb/mmBtu based on a 3-hour average
Greenhouse Gas (GHG) Emissions	120 pounds of CO_2 per million Btu of heat input. The auxiliary boiler may only use natural gas as a fuel.

6.2.1 Other Proposed Emission and Operating Limits.

1. The total heat input to the auxiliary boiler may not exceed 90,000 mmBtu in any consecutive 12-month period.

2. The maximum short-term emissions from the auxiliary boiler, excluding tuning/testing mode and equipment shakedown prior to commercial operation shall not exceed the following limits.

	CO[1]	NO_x[1]	PM_{10}, and $PM_{2.5}$[2]
Emission Limit, lb/hour	3.60	3.33	0.45
Averaging Period	3-hour	3-hour	n/a

Footnote 1: Compliance with the CO and NO_x emission limits are based on compliance emission testing.

Footnote 2: Compliance with the PM_{10}, and $PM_{2.5}$ emission limit is based on the combustion of only pipeline quality natural gas in the auxiliary boiler.

6.3 Natural Gas-Fired Natural Gas Dew Point Heater.

6.3.1 Proposed BACT Emission Limits.

Pollutant	BACT Emission Limit
Carbon Monoxide (CO)	0.04 lb/mmBtu based on a 3-hour average
Nitrogen Oxides (NO_x)	0.011 lb/mmBtu based on a 3-hour average
Particulate Matter (PM, PM_{10}, and $PM_{2.5}$)	The natural gas-fired natural gas heater may only use natural gas as a fuel. 0.005 lb/mmBtu based on a 3-hour average
Volatile Organic Compounds (VOC)	0.0055 lb/mmBtu based on a 3-hour average
Greenhouse Gas (GHG) Emissions	120 pounds of CO_2 per million Btu of heat input. The natural gas heater may only use natural gas as a fuel.

6.3.2 Other Proposed Emission and Operating Limits.

1. The maximum short-term emissions from the natural gas heater, excluding tuning/testing mode and equipment shakedown prior to commercial operation shall not exceed the following limits.

	CO[1]	NO_x[1]	PM_{10}, and $PM_{2.5}$[2]
Emission Limit, lb/hour	1.80	0.50	0.23
Averaging Period	3-hour	3-hour	n/a

Footnote 1: Compliance with the CO and NO_x emission limits are based on the manufacturer's design burner ratings.

Footnote 2: Compliance with the PM_{10}, and $PM_{2.5}$ emission limit is based on the combustion of only pipeline quality natural gas in the auxiliary boiler.

6.4 Two (2) Mechanical Draft Cooling Towers.

6.4.1 Proposed BACT Emission Limits.

Pollutant	BACT Emission Limit
Particulate Matter (PM, PM_{10}, and $PM_{2.5}$)	Emissions from each cooling tower shall be controlled by utilizing high efficiency drift eliminators with a maximum design drift loss of no more than 0.0005% of the circulating water flowrate

6.5 Diesel Engine Driven Emergency Fire Pump.

6.5.1 Proposed BACT Emission Limits.

Pollutant	BACT Emission Limit
Carbon Monoxide (CO)	1. The diesel engine-driven emergency fire pump shall comply with the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* 40 CFR 60, Subpart IIII. 2. The total operation of the fire pump may not exceed 200 hours per year.
Nitrogen Oxides (NO_x)	1. The diesel engine-driven emergency fire pump shall comply with the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* 40 CFR 60, Subpart IIII. 2. The total operation of the fire pump may not exceed 200 hours per year.
Particulate Matter (PM), PM_{10}, and $PM_{2.5}$	1. The diesel engine-driven emergency fire pump shall comply with the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* 40 CFR 60, Subpart IIII. 2. The total operation of the fire pump may not exceed 200 hours per year.

6.5.1 Other Proposed Emission and Operating Limits.

1. The fire pump engine rating shall not exceed 510 horsepower.

6.6 Natural Gas Piping Systems.

6.6.1 Proposed BACT Emission Limits.

Pollutant	BACT Emission Limit
Greenhouse Gas (GHG) Emissions	1. The permittee shall implement an auditory / visual / olfactory (AVO) monitoring program for detecting leaks in the natural gas piping components. 2. AVO monitoring shall be performed in accordance with a written monitoring program.

6.7 Sulfur Hexafluoride (SF_6) Insulated Breakers.

6.7.1 Proposed BACT Emission Limits.

Pollutant	BACT Emission Limit
Greenhouse Gas (GHG) Emissions	1. The Permittee shall install, operate, and maintain enclosed-pressure SF_6 circuit breakers with a maximum design annual leakage rate of 0.5% by weight. 2. The new circuit breakers shall be equipped with a leak detection system. 3. The permittee shall maintain records of the date that any leak is detected in a circuit breaker and the leak amount in weight percent. 4. The permittee shall maintain records of the date and the amount of SF_6 added to the circuit breakers.

Chapter 7. Ambient Air Quality Assessment.

A PSD air quality impact analysis has been performed for the pollutants NOx, PM_{10}, and $PM_{2.5}$. A minor-NSR modeling analysis has been performed for CO. The analyses follow all relevant EPA, Arizona Department of Environmental Quality (ADEQ), and Maricopa County air modeling guidance. Appendix B of this application presents the ambient air quality assessment modeling protocol and report.

The air quality impacts from the Project are insignificant for all pollutants and averaging intervals except for 1-hr NO_2 and 24-hr $PM_{2.5}$ impacts. For those two pollutants, cumulative NAAQS and PSD increment modeling analyses were performed that included the existing Redhawk emission units and other nearby sources. The results of the cumulative analyses demonstrate compliance with the NAAQS and PSD increments.

Additional PSD impact analyses were performed for soils and vegetation, Class II visibility, and associated growth. No adverse impacts were identified.

Class I area screening analyses were performed, which demonstrate that the Project impacts at the nearest Class I area (Superstition Wilderness area) are below the Class I Significant Impact Levels, and do not trigger Air Quality Relative Values (AQRV) analysis requirements.

Appendix A.

Maricopa County Air Quality Department Forms.

MARICOPA COUNTY
AIR QUALITY

Title V Permit Application

Instructions

No application shall be considered complete until the Control Officer has determined that all information required by the application (listed below) and the applicable statutes and regulations has been submitted. The Control Officer may waive certain application requirements for specific source types pursuant to Rule 200 (Permit Provision) and/or Rule 210 (Title V Permit Provisions) of the Maricopa County Air Pollution Control Regulations. For permit revisions, the applicant need only supply information which directly pertains to the revision, unless the source's proposed permit revision will change the permit from a non-Title V permit to a Title V permit. The Control Officer has developed a permitting handbook to assist sources in completing permit applications on Maricopa.gov/1817. A complete application must be submitted through the AQD Online Portal. All emission units must be input into the IMPACT system by the applicant at the time the application is submitted electronically.

Applicants are encouraged to submit proposed permit language or a redlined version of the source's current permit including suggested changes with the application. Any proposed language or suggested changes will be reviewed by the Department and may not be accepted into the final issued permit. However, the submittal of proposed permit language or a redlined version of the source's current permit may significantly reduce permit processing time.

Public Records

The submitted application and documents become the property of the Maricopa County Air Quality Department (hereafter referred to as the Department) and will not be returned. All submitted documents will be available to the public unless a notice of confidentiality has been submitted by the applicant in accordance with Arizona Revised Statutes (A.R.S.) §49-487 and accepted by the Department in accordance with Maricopa County Air Pollution Control Regulations, Rules 100 and 200. If confidentiality is claimed pursuant to A.R.S. §49-487, a fully completed application with confidential information clearly identified along with a separate copy of the application for public review without the confidential information and a written justification for the confidentiality claimed must be submitted.

Assistance and Resources

If you would like to schedule a pre-application meeting with permitting staff, please contact us at 602-506-6010 or email AQPermits@maricopa.gov. If you need assistance completing the application package, please contact our Business Assistance Office at 602-506-5102 or email AQBusinessAssistance@maricopa.gov. Maricopa County Air Pollution Control Regulations are available at the above address or may be viewed and/or downloaded from the Adopted Rules page of our web site.

Required Information

The applicant shall supply the following:

1. A complete and signed copy of the Title V Application Cover Page (below)
2. Description of the process to be carried out at the facility and in each process unit (include Source Classification Code)
3. Description of product(s)
4. Description of Alternate Operating Scenario (AOS), if desired by applicant (include Source Classification Code)
5. Description of alternate operating scenario product(s), if applicable
6. A flow diagram including all processes
7. A material balance for all processes if emission calculations are based on a material balance.
8. Emissions related information:
    a. The source shall submit the potential emission of the regulated pollutants as defined in Rule 100 (General Provisions and Definitions) for all emission sources. Emissions shall be expressed in pounds per hour, tons per year, and such other terms as may be requested. Emissions information shall include fugitive emissions in the same manner as stack emissions, regardless of whether the source category in question is included in the list of sources contained in the definition of major source in Rule 100 (General Provisions and Definitions).
    b. The source shall identify and describe all points of emissions and submit additional information related to the emissions of regulated air pollutants sufficient to verify which requirements are applicable to the source and sufficient to determine any fees pursuant to Rule 280 (Fees).
9. Citations and descriptions of all applicable requirements as defined in Rule 100 (General Provisions and Definitions), including voluntarily accepted limits pursuant to Rule 220 (Non-Title V Permit Provisions)

10. An explanation of any voluntarily accepted limits established pursuant to Rule 220 (Non-Title V Permit Provisions) and of any proposed exemptions from otherwise applicable requirements
11. The following information to the extent it is needed to determine or regulate emissions or to comply with any voluntarily accepted limits established pursuant to Rule 220 (Non-Title V Permit Provisions):
    a. Maximum annual process rate for each piece of equipment which generates air emissions
    b. Maximum annual process rate for the whole plant
    c. Maximum rated hourly process rate for each piece of equipment which generates air emissions
    d. Maximum rated hourly process rate for the whole plant
    e. For all fuel burning equipment including generators, a description of fuel use, including the type used, the quantity used per year, the maximum and average quantity used per hour, the percent used for process heat (i.e., heat other than for HVAC or domestic hot water), and higher heating value of the fuel. For solid fuels and fuel oils, state the potential sulfur and ash content
    f. A description of all raw materials used and the maximum annual and hourly, monthly, or quarterly quantities of each material used
    g. Anticipated operating schedules:
        i. Percent of annual production by season
        ii. Days of the week normally in operation
        iii. Shifts of hours of the day normally in operation
        iv. Number of days per year in operation
    h. Limitations on the source operations and any work practice standards affecting emissions
    i. A demonstration of how the source will meet any limitations accepted voluntarily pursuant to Rule 220 (Non-Title V Permit Provisions)
12. A description of all process and control equipment for which permits are required including:
    a. Name
    b. Make
    c. Model
    d. Serial number
    e. Date of manufacture
    f. Size/production capacity
    g. Type
13. Stack information:

a. Identify each emission point with a unique number for this plant site, consistent with emission point identification used on plot plan, previous permits, and Emissions Inventory Questionnaire. Include fugitive emissions.
b. Description
c. Building dimensions
d. Exit gas temperature
e. Exit gas velocity
f. Height
g. Inside dimensions
h. Stack exit configuration if other than a round vertical stack. Show length and width for a rectangular stack. Indicate if horizontal discharge.
i. Stack's height above supporting or adjacent structures if structure is within 3 "stack heights above the ground" of the stack
j. Dimensions of nonpoint sources as defined in R18-2-101
k. Associated regulated air pollutants as defined in Rule 100 (General Provisions and Definitions)
l. Pounds per hour (lb/hr), which is the maximum potential emission rate expected
m. Tons per year, which is the annual maximum potential emission expected and takes into account process operating schedule

14. Site diagram which includes:
    a. Property boundaries
    b. Adjacent streets or roads
    c. Directional arrow
    d. Elevation
    e. Closest distance between equipment and property boundary
    f. Equipment layout
    g. Location of emission points and non-point emission areas - UTM coordinates are required only if the source is required to perform refined modeling for the purposes of demonstrating compliance with ambient air quality guidelines.
    h. Location of air pollution control equipment
    i. Ground elevation of facility above mean sea level (ft)
15. Air pollution control information:
    a. Description of or reference to any applicable test method for determining compliance with each applicable requirement
    b. Identification, description, and location of air pollution control equipment, including spray nozzles, and hoods

c. The rated capacity and operating efficiency of air pollution control equipment
d. Data necessary to establish required efficiency for air pollution control equipment (e.g., air to cloth ratio for baghouses, pressure drop for scrubbers, and manufacturer warranty information)
e. Evidence that operation of the new or modified pollution control equipment will not violate any ambient air quality standards or the degree of consumption of the maximum allowable increases allowed under limitation of pollutants in classified attainment and unclassified areas that is expected to occur
f. Identification and description of compliance monitoring devices or activities

16. Equipment manufacturer's bulletins and shop drawings, where appropriate
17. Compliance plan:
    a. A description of the compliance status of the source with respect to all applicable requirements including, but not limited to:
        i. For applicable requirements with which the source is in compliance, a statement that the source will continue to comply with such requirements
        ii. For applicable requirements that will become effective during the permit term, a statement that the source will meet such requirements on a timely basis
        iii. For requirements for which the source is not in compliance at the time or permit issuance, a narrative description of how the source will achieve compliance with such requirements
        iv. For applicable requirements associated with a proposed AOS, a statement that the source will meet such requirements upon implementation of the AOS. If a proposed AOS would implicate an applicable requirement that will become effective during the permit term, a statement that the source will meet such requirements on a timely basis.
        v. A demonstration that the source or modification will comply with the applicable requirements contained in Regulation III - Control of Air Contaminants
        vi. A demonstration that the source or modification will comply with the applicable requirements contained in rules promulgated pursuant to A.R.S. § 49-480.03 (Federal Hazardous Air Pollutants (HAPS) Program; Date Specified by Administrator; Prohibition)
        vii. A demonstration that the source or modification will comply with any voluntarily accepted limitations pursuant to Rule 220 (Non-Title V Permit Provisions)
    b. A compliance schedule as follows:
        i. For applicable requirements with which the source is in compliance, a statement that the source will continue to comply with such requirements

ii. For applicable requirements that will become effective during the permit term, a statement that the source will meet such requirements on a timely basis. A statement that the source will meet in a timely manner applicable requirements that become effective during the permit term shall satisfy this provision, unless a more detailed schedule is expressly required by the applicable requirement.
iii. A schedule of compliance for sources that are not in compliance with all applicable requirements at the time of permit issuance. Such a schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the source will be in noncompliance at the time of permit issuance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based.
iv. For applicable requirements associated with a proposed AOS, a statement that the source will meet such requirements upon implementation of the AOS. If a proposed AOS would implicate an applicable requirement that will become effective during the permit term, a statement that the source will meet such requirements on a timely basis. A statement that the source will meet in a timely manner applicable requirements that become effective during the permit term will satisfy this provision, unless a more detailed schedule is expressly required by the applicable requirement.

c. A schedule for submission of certified progress reports no less frequently than every six months for sources required to have a schedule of compliance to remedy a violation
d. The compliance plan content requirements shall apply and be included in the acid rain portion of a compliance plan for an affected source, except as specifically superseded by regulations promulgated under Title IV of the Act with regard to the schedule and method the source will use to achieve compliance with the acid rain emissions limitations.

18. Compliance certification:
    a. A certification of compliance with all applicable requirements including voluntarily accepted limitations pursuant to Rule 220 (Non-Title V Permit Provisions) by a responsible official consistent with Rule 210 (Title V Permit Provisions) or Rule 220 (Non-Title V Permit Provisions). The certification shall include:

i. Identification of the applicable requirements which are the basis of the certification,
ii. A statement of methods used for determining compliance, including a description of monitoring, recordkeeping, and reporting requirements and test methods,
iii. A schedule for submission of compliance certifications during the permit term to be submitted no less frequently than annually or more frequently if specified by the underlying applicable requirement or by the permitting authority,
iv. A statement indicating the source's compliance status with any applicable enhanced monitoring and compliance certification requirements, and
v. A certification of truth, accuracy, and completeness pursuant to Rule 210 (Title V Permit Provisions).

19. Acid rain compliance plan:
    a. Sources subject to the Federal acid rain regulations shall use nationally standardized forms for acid rain portions of permit applications and compliance plans, as required by regulations promulgated under Title IV of the Act.
20. A new major source as defined in Rule 240 (Federal Major New Source Review) or a major modification shall submit all information required in this application and information necessary to show compliance with Rule 240 (Federal Major New Source Review) including, but not limited to a demonstration that:
    a. The impact analyses requirements in Section 304.16 and Section 305.3 of Rule 240 are met and demonstrate that the new major source or major modification will not interfere with the attainment or maintenance of any applicable NAAQS.
    b. The proposed major source or major modification of a major source will comply with any applicable new source performance standards (NSPS) in 40 CFR Part 60.
    c. The proposed major source or major modification will comply with the applicable standards for hazardous air pollutants contained in Section 112 of the Clean Air Act.
    d. The new major source or major modification will not have an adverse impact on visibility in any Federal Class I area or mandatory Class I Federal area, as determined by Sections 304 and/or 305 of this Rule 240 and the applicant will satisfy all the applicable visibility requirements contained in Sections 304 and/or 305 of Rule 240. If required by Sections 304 or 305 of Rule 240, a demonstration of the impact on visibility shall be made according to the requirements of 40 CFR 51.307(a), 40 CFR 52.21(o), and (p)(1) through (p)(4) shall be included with the application.
    e. All applicable requirements of the SIP will be met, including but not limited to the requirements contained in Rule 200 (Permit Requirements), Rule 210 (Title V Permit

Provisions), Rule 240 (Federal Major New Source Review (NSR)), Rule 241 (Minor New Source Review (NSR)), Rule 245 (Continuous Source Emission Monitoring), and Rule 270 (Performance Tests).

f. The new major source or major modification will be in compliance with whatever emission limitation, design, equipment, work practice or operational standard, or combination thereof is applicable to the source or modification to satisfy BACT or LAER as applicable.
    i. In the case of a new major source as defined in Rule 240 (Federal Major New Source Review) or a major modification subject to an emission limitation which is lowest achievable emission rate (LAER) for that source or facility, the application shall contain a determination of LAER that is consistent with the requirements of the definition of LAER contained in Rule 240 (Federal Major New Source Review). The demonstration shall contain the data and information relied upon by the applicant in determining the emission limitation that is LAER for the source or facility for which a permit is sought.
    ii. In the case of a new major source as defined in Rule 240 (Federal Major New Source Review) or major modification subject to an emission limitation which is best available control technology (BACT) for that source or facility, the application shall contain a determination of BACT that is consistent with the requirements of the definition of BACT contained in Rule 100 (General Provisions and Definitions). The demonstration shall contain the data and information relied upon by the applicant in determining the emission limitation that is BACT for the source or facility for which a permit is sought.

g. The new major source or major modification will comply with all applicable requirements of Regulation III-Control of Air Contaminants of these rules.

h. The requirements for Plantwide applicability limitation (PAL) permits for any existing major stationary source comply with the provisions, including application requirements, contained in 40 CFR 51.165(f)(1) through (15) and/or 40 CFR 51.166 (w)(1) through (15).

i. All existing major sources owned or operated by the applicant (or any entity controlling, controlled by, or under common control with such person) in the State are in compliance with, or are on a schedule of compliance for, all conditions contained in permits for each of the sources and all other applicable emission limitations and standards under the Act and in Rule 240.

j. The increased emissions, calculated pursuant to Section 304 of Rule 240, from a major source or major modification have been offset by reductions in the emissions of each pollutant for which the area has been designated as nonattainment and for which the proposed project will result in a new major stationary source or a major modification for that nonattainment pollutant.

k. The applicant for a new major source or major modification to a major source located in a nonattainment area performed an analysis of alternative sites, sizes, production processes and environmental control techniques for such new major source or major modification to demonstrate that the benefits of the new major source or major modification significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification.

21. For all new sources or modifications to existing sources the applicant shall submit all information required in this application and information necessary to show compliance with or exemption from Rule 241 (Minor New Source Review):
    a. The requirements of Rule 241 (Minor New Source Review) apply to the following:
        i. A new source that has the potential to emit a regulated minor NSR pollutant in an amount equal to or greater than any of the permitting thresholds specified in Rule 100 (General Provisions and Definitions) including the minor NSR modification thresholds in section 200.72 of Rule 100, or
        ii. A modification to an existing source that increases the potential to emit a regulated minor NSR pollutant in an amount equal to or greater than any of the minor modification thresholds in section 200.72 of Rule 100.
    b. For new sources: An ambient air quality impact assessment is required if the source has a potential to emit a regulated minor NSR pollutant in an amount equal to or greater than any of the minor NSR modification thresholds in section 200.72 of Rule 100
    c. For existing sources: An ambient air quality impact assessment is required if the source increases its potential to emit a regulated minor NSR pollutant in an amount equal to or greater than and of the minor NSR modification thresholds in section 200.72 of Rule 100
    d. A source is exempt from the requirements of Rule 241 on a pollutant basis if emissions are subject to major source requirements under Rule 240 (Federal Major New Source Review).
22. Calculations on which all information requested in this application is based
23. An application to construct or reconstruct any major source of hazardous air pollutants shall contain a determination that maximum achievable control technology (MACT) for new sources under Section 112 of the Act will be met.
    a. Where MACT has not been established by the Administrator, such determination shall be made on a case-by-case basis under 40 CFR 63.40 through 63.44. For purposes of

this section of this rule, constructing or reconstructing a major source shall have the meaning prescribed in 40 CFR 63.41.

24. If a permit applicant requests terms and conditions allowing for the trading of emission increases and decreases at the permitted source solely for the purpose of complying with a federally enforceable emission cap that is established in the permit independent of otherwise applicable requirements, the permit applicant shall include in its application proposed replicable procedures and permit terms that ensure the emissions trades are quantifiable and enforceable.
25. A source that has submitted information with an application under a claim of confidentiality under A.R.S. § 49-487 and Rule 200-Permit Requirements of these rules shall also submit a copy of the confidential information directly to the Administrator.
26. Duty to Supplement or Correct Application: Any applicant who fails to submit any relevant facts or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application but prior to release of a proposed final permit.

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Title V Permit Application Cover Page

Important: Please note that as the engineer reviews your application and prepares your permit, email will be the primary means for communication with you. Please ensure your email address is correct.

1. Permit to be issued to (business license name of organization that is to receive the permit): Arizona Public Service Company (APS)
2. Mailing Address: 400 N. 5th Street, Mail Station 9303
   City: Phoenix State: AZ Zip Code: 85004
3. Facility Name (if different from item #1 above): Desert Sun Power Plant
4. Name(s) of Owner or Operator: Arizona Public Service Company
   Phone: ______ Email: ______
5. Name of Owner's Agent: Mark Hajduk
   Phone: 602-250-3394 Email: Mark.Hajduk@aps.com
6. Plant/Site Manager or Contact Person: ______
   Phone: ______ Email: ______
7. Proposed Equipment/Plant Location Address: ______
   City: Gila Bend County: Maricopa Zip Code: ______
   Section/Township/Range: 35, 36/T05S/R07W Latitude: 32.9480 Longitude: 112.9410
8. General Nature of Business: Electric Utility Electric Power Generation
   Standard Industrial Classification Code: 4911
9. Type of Organization: ☒ Corporation ☐ Individual Owner ☐ Partnership
   ☐ Govt. Entity, Government Facility Code: ______
10. Permit Application Basis (check all that apply):
    ☒ New Source ☐ Renewal of Existing Permit ☐ Permit Revision ☐ Portable Source
    For renewal or **modification, include the existing permit number and date of commencement of construction or modification:** ______
    Will any of the equipment be leased to another individual or entity? ☐ Yes ☐ No
11. **I, the undersigned Responsible Official, certify that based on information and belief formed after** reasonable inquiry, the statements and information in the document are true, accurate, and complete.
    Responsible Official Signature: [signature] Date: 5/13/2026
    Responsible Official Printed Name: Peter Candelaria
    Responsible Official Title: VP Generation Development
    Phone: 602·931·7855 Email: Peter.Candelaria@aps.com

Appendix B.

Air Quality Modeling Protocol and Report.

Appendix B

Desert Sun Power Plant

Air Quality Modeling Protocol and Report to support the Construction and Title V Air Quality Operating Permit Application

New Natural Gas-Fired Combined Cycle Combustion Turbine Electric Generating Facility

May 2026

Prepared for:

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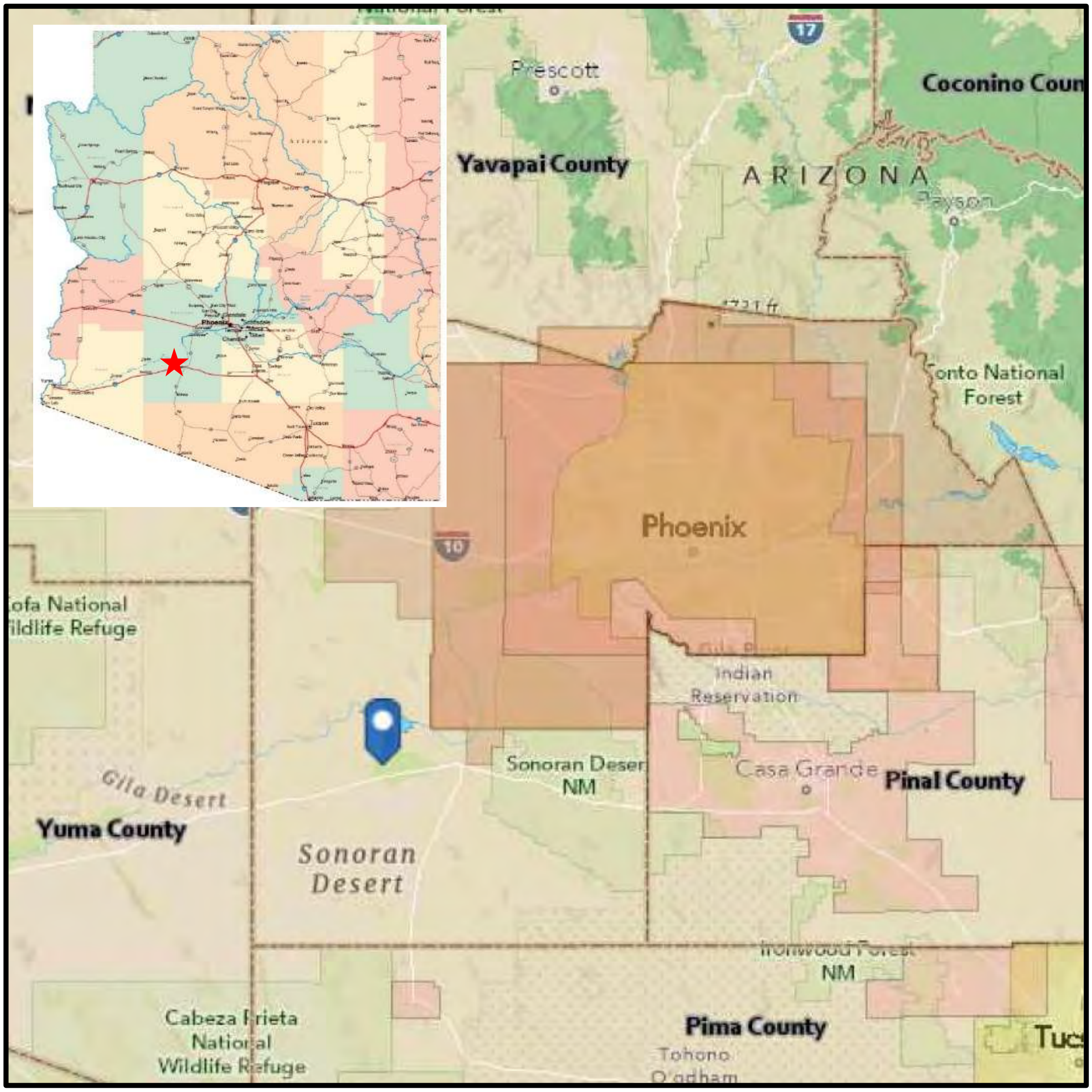
1.0 Introduction and Project Background

Arizona Public Service (APS) is proposing to construct and operate a new power plant in Gila Bend, Maricopa County, the Desert Sun Power Plant (the Project). The Project will be located near the intersection of Painted Rock Road and West Powerline Road in Gila Bend, Arizona, in an area that is classified as attainment or unclassified for all criteria air pollutants. Figure 1 shows the general location of the proposed power plant in the State of Arizona and in Maricopa County, and the boundaries of the Maricopa carbon monoxide (CO), particulate matter less than 10 microns (PM_{10}), and ozone nonattainment areas. The power plant will consist of two GE Vernova Model 7HA.02 natural gas-fired combustion turbine (CT) electric generating units.

Based on the potential emissions and regulatory applicability analyses presented in the Project's *Construction and Title V Air Quality Operating Permit Application* (herein referred to as the Permit Application), the Project will trigger Prevention of Significant Deterioration (PSD) review for the criteria pollutants NO_X, particulate matter (PM), PM_{10}, $PM_{2.5}$, CO, and VOC. One of the PSD permitting requirements is to perform an air quality impact analysis that demonstrates the Project will not cause or contribute to a violation of any National Ambient Air Quality Standard (NAAQS) or PSD increment. EPA has published the *Guideline on Air Quality Models*, 40 CFR Part 51 Appendix W (herein referred to as "EPA GAQM") that provides guidance for performing PSD air quality impact analyses.

This document is the air quality modeling protocol and report for the Project. The air quality modeling procedures conform with applicable requirements in EPA's GAQM, the Arizona Department of Environmental Quality (ADEQ) *Air Dispersion Modeling Guidelines for Arizona Air Quality Permits*, November 2019 (herein referred to as the "ADEQ Guidelines") and the *Maricopa County Air Quality Permitting Handbook* (August 2023).

Figure 1 - Location of the Desert Sun Power Plant



1.1 Project Description

The Project will utilize two GE Vernova Model 7HA.02 natural gas-fired CT electric generating units as the prime movers. These CTs will be constructed as combined cycle (CC) units in a 1 x 1 configuration, meaning that each CT will have a separate heat recovery steam generator (HRSG) and a separate steam turbine/electric generator set. Each CT will be equipped with state-of-the-art air quality control systems including dry-low NO_X combustors and selective catalytic reduction (SCR) for NO_X control and oxidation catalysts for CO and VOC control. Additional supporting equipment includes a natural gas-fired auxiliary boiler, a natural gas-fired natural gas conditioning or dew point heater, two mechanical draft cooling towers for lube oil, and a diesel engine emergency fire pump. Refer to the Permit Application for additional specifications of the CTs and other supporting equipment.

1.2 Site Description

The Project site is in a sparsely populated area approximately 100 km southwest of downtown Phoenix, at an elevation of approximately 720 ft above mean sea level (amsl). The site is in the northern reaches of the low-land Sonoran Desert, with nearby agricultural land uses. Scattered low mountain ranges occur in the area, including the Painted Rock Mountains to the west, the Gila Mountains to the north, and the Maricopa Mountains to the east, with the highest elevations of approximately 1,500 to 3,200 feet amsl. Other than the mountains, the topography at the Project area is generally flat. The Gila River and Painted Rock Reservoir are located approximately 8 km to the north, and the river orientation is east/west in the Project area.

1.3 Regional Climatology

Most of the following discussion is taken from a climate summary compiled by the National Weather Service Forecast Office in Phoenix, Arizona found at the following internet link: http://www.public.asu.edu/~aunjs/ClimateofPhoenix/phxwx.htm .

The climate in the Phoenix area is of a desert type with low annual rainfall and low relative humidity. Daytime temperatures are high throughout the summer months. The winters are mild. Most deserts undergo drastic fluctuations between day and nighttime temperatures, but not the Phoenix metropolitan area due to the urban heat island effect. As the city has expanded, average summer low temps have been rising steadily. The daily heat of the sun is stored in pavement, sidewalks, and buildings, and is radiated back out at night. During the summer, overnight lows greater than 80 °F are commonplace.

There are two separate rainfall seasons. The first occurs during the winter months from November through March when the area is subjected to occasional storms from the Pacific Ocean. While this is classified as a rainfall season, there can be periods of a month or more in this or any other season when practically no precipitation occurs. Snowfall occurs very rarely in the Salt River Valley, while light snow occasionally falls in the higher mountains surrounding the valley. The second rainfall period occurs during July and August when Arizona is subjected to widespread thunderstorm activity whose moisture supply originates in the Gulf of Mexico, in the Pacific Ocean off the west coast of Mexico and in the Gulf of California. The spring and fall months are generally dry, although precipitation in substantial amounts has fallen occasionally during every month of the year.

The valley floor, in general, is rather free of strong wind. During the spring months southwest and west winds predominate and are associated with the passage of low-pressure troughs. During the thunderstorm season in July and August, there are often local, strong, gusty winds with considerable blowing dust.

These winds generally come from a northeasterly to southeasterly direction. Throughout the year there are periods, often several days in length, in which winds remain under 10 miles per hour.

Sunshine in Phoenix area averages 86 percent of possible, ranging from a minimum monthly average of around 78 percent in January and December to a maximum of 94 percent in June. During the winter, skies are sometimes cloudy, but sunny skies predominate, and the temperatures are mild. During the spring, skies are also predominantly sunny with warm temperatures during the day and mild pleasant evenings. Beginning in June, daytime weather is hot. During July and August, there is an increase in humidity, and there is often considerable afternoon and evening cloudiness associated with cumulus clouds building up over the nearby mountains. Summer thunder-showers seldom occur in the valley before evening.

The autumn season, beginning during the latter part of September, is characterized by sudden changes in temperature. The change from the heat of summer to the mild winter temperatures usually occurs during October. The normal temperature change from the beginning to the end of this month is the greatest of any of the twelve months in central Arizona. By November, the mild winter season is established in the Salt River Valley region.

2.0 Regulatory Status

The Project will be located near Gila Bend, Arizona, in Maricopa County. The air permitting authority is the Maricopa County Air Quality Department (MCAQD).

2.1 Source Designation

The proposed Project will be a major source under both Maricopa County Rule 240 (implementing the PSD Program) and Rule 210 (implementing Title V requirements). As described in the Permit Application, the proposed Project emissions will trigger PSD review for the pollutants NO_X, CO, VOC, PM, PM_{10}, and $PM_{2.5}$.

2.2 Area Classifications

The Project location is classified as attainment for all criteria air pollutants. The Maricopa 2015 8-hr ozone nonattainment area (NAA) is located approximately 13 km to the east/northeast.

2.3 Baseline Dates and Area

A PSD increment is the maximum increase in concentration allowed above an established baseline concentration. The baseline concentration represents the actual ambient concentration existing at the baseline date, defined as the time of the first complete PSD permit application in each area, referred to as the "baseline area" or "air quality control region" (AQCR). There are two baseline dates that are defined: major source baseline dates and minor source baseline dates. The major source baseline date identifies the point in time after which major sources affect available increment, while the minor source baseline date identifies the point in time after which actual emission changes from all sources (both major and minor) affect available increment. The amount of PSD increment that has been consumed within an area is determined from the actual emission increases and decreases that have occurred since the applicable baseline date.

The applicable major source baseline dates for the Maricopa Intrastate AQCR are January 6, 1975, for SO_2 and $PM_{10;}$ February 8, 1988, for NO_2; and October 20, 2010, for $PM_{2.5}$. The minor source baseline dates are March 3, 1980, for SO_2 and PM_{10}; January 20, 1993, for NO_2, and May 10, 2015, for $PM_{2.5}$.

3.0 Air Quality and Meteorological Data Requirements

3.1 Preconstruction Air Quality Monitoring

The collection of ambient air quality data for criteria pollutants that trigger PSD review and for which the Project impacts are above the Significant Monitoring Concentrations (SMCs) is required prior to construction of a new major source, unless representative data from an existing monitor is available. Note that SMCs do not exist for $PM_{2.5}$ impacts. As will be shown later in this modeling report, all Project impacts are below the SMCs, therefore the only pre-construction air quality data required for the Project is for $PM_{2.5}$. Note that Section 3.4 of this report discusses the ambient background concentrations that were used for any required cumulative NAAQS analyses.

This section contains an analysis of the representativeness of nearby existing $PM_{2.5}$ ambient monitoring data for use in lieu of preconstruction monitoring data collection. EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration*, 1987, discusses three criteria that help determine the representativeness of existing monitoring data for fulfilling the preconstruction monitoring requirement: the quality of the data, the currentness of the data, and the monitor location. The existing monitoring data must meet quality assurance procedures that are required for the operation of PSD and State and Local Air Monitoring Stations (SLAMS) air monitoring stations. The existing data should have been collected in the recent 3-year period preceding the permit application.

MCAQD collects accurate and timely ambient air quality monitoring data within Maricopa County. In cooperation with the EPA and other governmental agencies, the Division operates numerous SLAMS air quality sites which measure several criteria pollutants and regularly reports on the monitoring station objectives and data results in periodic Network Plans and Network Assessments. These stations are operated in compliance with SLAMS quality assurance procedures. MCAQD has analyzed the air quality data from all stations in accordance with recommendations in the ADEQ Guidelines and has made available data tables with approved background air quality concentration values. These data generally meet the criteria for use as pre-construction air monitoring data.

The two closest $PM_{2.5}$ monitoring stations operated by MCAQD are the Glendale station (located 98 km from the Project) and the West Phoenix station (located 96 km from the Project). The Glendale station (AQS # 04-013-2001) is in a residential neighborhood, while the West Phoenix station is in a high-density residential neighborhood with nearby industrial districts. The general setting and source environment of the Glendale station more closely matches the rural Project site than does the West Phoenix station. The Glendale station spatial scale is neighborhood, which is appropriate for use as pre-construction monitoring data. Data from the recent 2023-2025 period will be used in the analysis.

Given the similar characteristics Glendale station to the Project area, the air quality data from this station fulfills the PSD pre-construction air quality monitoring requirements. Section 3.4 presents a discussion of the background concentration values that will be used in any required cumulative NAAQS analyses.

3.2 Post-Construction Air Quality Monitoring

Post-construction air quality monitoring is not proposed for the Project.

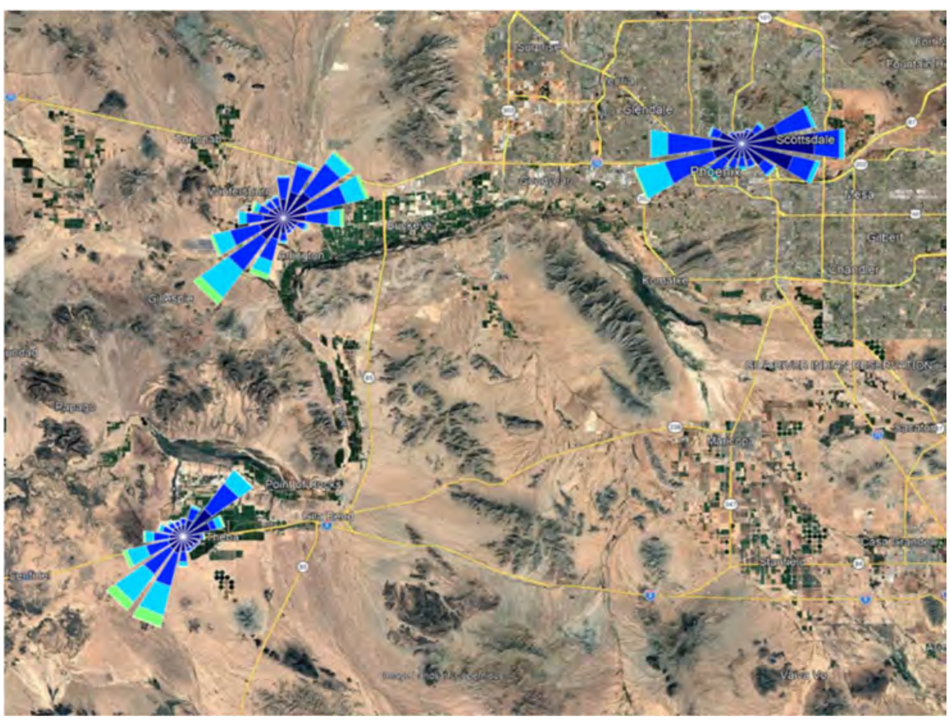
3.3 Meteorological Monitoring

ADEQ has processed meteorological data from numerous meteorological monitoring stations using EPA's AERMET system. Data is available for the five-year period of 2020 to 2024. One of the stations is the Sky Harbor National Weather Service Automated Surface Observing System (ASOS) station, located approximately 100 km to the northeast of Project. This meteorological data is typically used as representative data in dispersion modeling for projects in the Phoenix area.

Meteorological data is also collected by APS at the Palo Verde Generating Station (PVGS), located approximately 50 km north of Project. A 60-meter meteorological monitoring tower collects wind speed and wind direction data at 10-meter and 60-meter levels. The tower is operated and calibrated in accordance with *Meteorological Monitoring Programs for Nuclear Power Plants Regulatory Guide No. 1.23*, Revision 1, United States Nuclear Regulatory Commission (NRC), March 2007. The NRC meteorological monitoring requirements for instrument specifications, siting, data collection, and data validation meet or exceed the EPA requirements for onsite meteorological monitoring described in *Meteorological Monitoring Guidance for Regulatory Modeling Applications*, EPA-454/R-99-005, February 2000. Therefore, the PVGS onsite meteorological data is suitable for regulatory modeling.

ADEQ has made available state-wide prognostic meteorological data for 2013 – 2015 (12km WRF simulations and MMIF processed data for each 12km grid cell), which can be used to compare wind flow patterns at various locations. Figure 2 presents the 3-year wind roses from the grid cells closest to the Project (lower left), the PVGS meteorological tower (upper left), and the Phoenix ASOS station (right). These three wind roses are similar, but the wind flow patterns at the Project site and the PVGS tower show better agreement than the Sky Harbor data.

Figure 2 - Comparison of WRF Wind Roses



Given the similarity of surface conditions and land use at PVGS and Project (both rural locations) and the better agreement for these two WRF wind roses, the PVGS data set has been selected as the most representative meteorological data set for the Project's near-field modeling analyses. The data processing performed on the PVGS data is described in Section 5.2 of this protocol/report.

3.4 Background Concentrations

The impacts of non-nearby background sources and other not explicitly modeled sources are accounted for by using monitored air quality data (i.e., background concentrations). EPA's GAQM discusses requirements for background air quality concentrations that are "an essential part of the total air quality concentration to be considered in determining source impacts." Appendix W states that typically "air quality data should be used to establish background concentrations in the vicinity of the source(s) under consideration." The ADEQ Guidelines discusses the data processing requirements and methods to determine the background concentration values, which were used for this data compilation.

As will be shown later in this report, the only pollutants for which background data is required are 24-hr and annual average $PM_{2.5}$ and 1-hr average NO_2. The background data station that will be used in this analysis are the Glendale station for $PM_{2.5}$ data and the Buckeye station for NO_2 data. These are the closest stations to the Project area.

MCAQD operates the Buckeye monitoring station (AQS # 04-013-4011), located approximately 60 km to the northeast of the Project. The Buckeye site monitors CO, NO_2, and PM_{10}. The station is located in a rural, agricultural setting, similar to the Project. The monitoring spatial scales of this station are neighborhood for CO and PM_{10}, and urban for NO_2, which are appropriate for use as background data. The representativeness of the Glendale station for $PM_{2.5}$ data has already been discussed in Section 3.1 of this report.

The background concentration data that will be used in the Project air quality impact analyses are for the period 2023-2025, as presented in Table 1.

Table 1 - Background Air Quality Concentration Data

Pollutant	Averaging Interval	2023	2024	2025	Design Conc.
NO_2	1-hr ppb	33.0	32.0	30.0	31.7
	Annual ppb	7.9	8.0	7.3	7.7
$PM_{2.5}$	24-hr ug/m3	22.9	19.0	16.0	19.3
	Annual ug/m3	7.0	7.5	6.8	7.1

4.0 Project Emission Sources

The new Project emission units include two new CTs, two lube oil cooling towers, a natural gas dew point conditioning heater, and a diesel fire pump. All stacks exhaust vertically and do not have rain caps and were therefore modeled as default point sources in AERMOD. All source locations are based upon a NAD83, UTM Zone 12 projection. Refer to Section 5.3 for a discussion on modeled source emissions.

5.0 Class II Area Analyses

5.1 Scope and Model Selection

Based on the regulatory analysis in the Permit Application, PSD air quality analyses are required for NO_X, CO, PM_{10}, $PM_{2.5}$, and VOC (ozone) emissions. The primary guidance for performing PSD air quality analyses is EPA's GAQM, the *AERMOD Users Guide* and related addendums, and EPA's *AERMOD Implementation Guide*. In addition, EPA has also developed $PM_{2.5}$ permit modeling guidance and 1-hr NO_2 and SO_2 NAAQS modeling guidance. All procedures used for the Project's air quality impact analysis are consistent with these guidance documents.

Air modeling analyses are typically conducted in two steps: a "project-only" significant impact analysis, and if required a cumulative impact or "full" analysis. The significant impact analysis first estimates ambient impacts resulting from emissions from only the proposed Project. When the maximum ambient concentrations of a pollutant are below the Significant Impact Level ("SIL"), the emissions from the proposed source are not expected to have a significant impact on ambient air concentrations and further air quality analysis is not required for that pollutant and averaging interval. The use of the SILs is further discussed in Section 5.7 of this protocol.

If the Project's ambient impacts exceed the SIL for any pollutant and averaging interval, a cumulative NAAQS and PSD increment analysis is performed for those pollutants and averaging intervals, using receptors that are within the Significant Impact Area (SIA). The cumulative analysis includes other nearby sources in addition to the Project emission sources.

For any required 1-hr NO_2 NAAQS modeling, EPA and ADEQ have developed guidance for "intermittent sources". The guidance recommends that modeling should be based on "emission scenarios that can logically be assumed to be relatively continuous or which occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations." The EPA guidance allows the reviewing agency to exempt intermittent units, such as for emergency generators and fire pump engines, form the modeling analysis. The ADEQ guidance recommends that intermittent sources are modeled using the annualized average emission rates. The ADEQ methodology was used for the 1-hr NO_2 modeling of the emergency fire pump engine.

The EPA and ADEQ intermittent source guidance does not apply to the 24-hr PM_{10} and $PM_{2.5}$ modeling of the emergency fire pump. Instead, the emergency fire pump was assumed to be operated and tested only during daytime hours between 8am and 5pm and was modeled using AERMOD HROFDY emission factors for these daytime hours, using the maximum hourly emission rates.

The AERMOD model was used for the air quality analyses, with the regulatory default option set. AERMOD is a steady-state plume dispersion model that simulates transport and dispersion from multiple point, area, or volume sources based on an up-to-date characterization of the atmospheric boundary layer. AERMOD uses Gaussian distributions in the vertical and horizontal for stable conditions, and in the horizontal for convective conditions; the vertical distribution for convective conditions is based on a bi-Gaussian probability density function of the vertical velocity. For elevated terrain AERMOD incorporates the concept of the critical dividing streamline height, in which flow below this height remains horizontal, and flow above this height rises over terrain. AERMOD also uses the advanced PRIME algorithm to account for building wake effects.

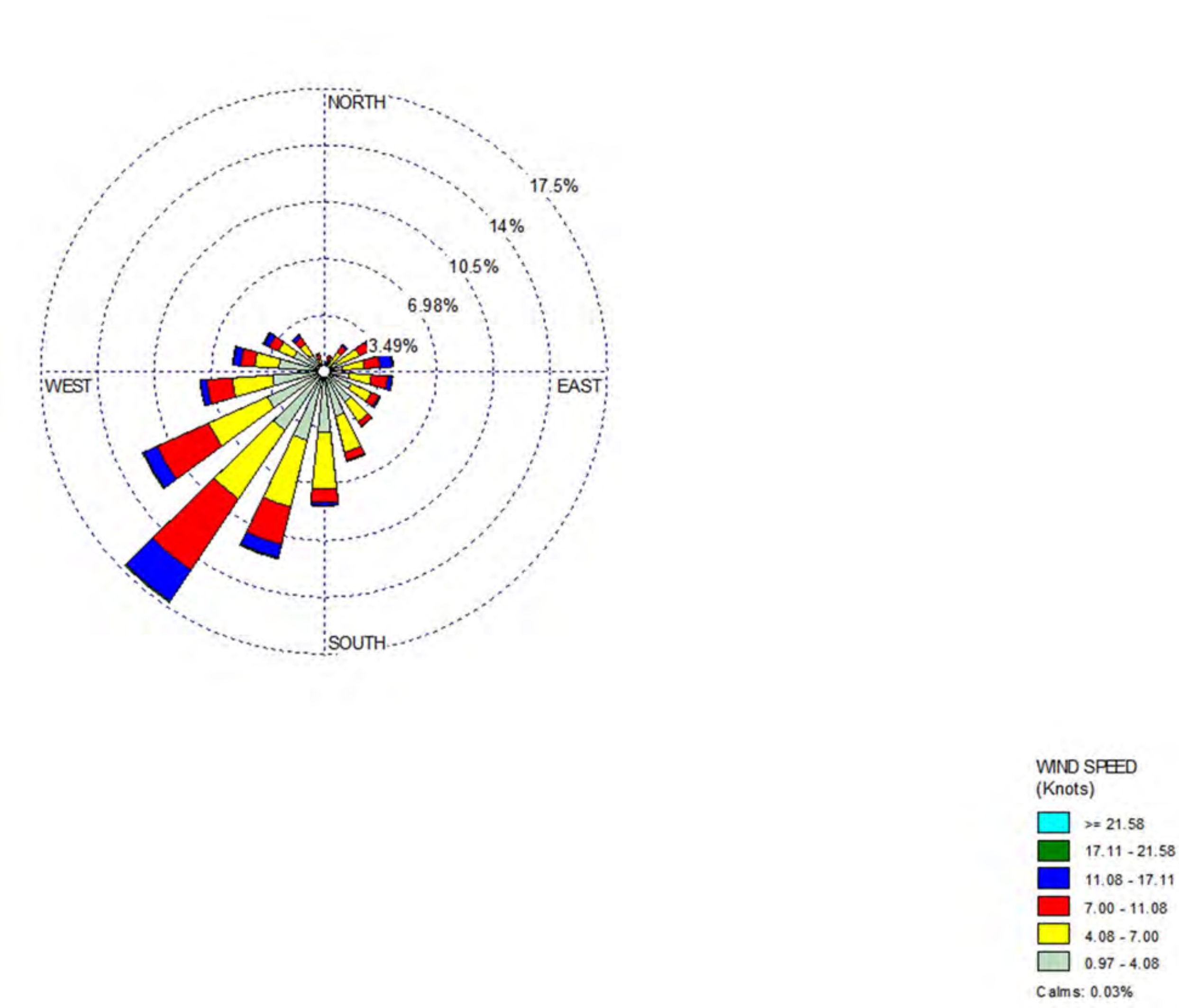
5.2 Meteorological Data and AERMET Processing

Meteorological data from the PVGS tower was processed using EPA's AERSURFACE and AERMET programs, following procedures and guidance in EPA's GAQM and the AERMET manual. The meteorological data set for the period 2020-2024 consisted of "ONSITE" 10-meter and 60-meter wind speed and direction data from the PVGS 60-meter meteorological tower, "SURFACE" meteorological data from the nearest representative ASOS station (Sky Harbor airport station with IDs of WBAN-23183 and WMO-722780), and "UPPER AIR" data from the Tucson station (WBAN 23160 and WMO-722740).

The stage 1 AERMET processing extracted the onsite, surface, and upper air data sets and performed the standard Quality Assessment reviews. The threshold wind speed used for the onsite data set was 0.5 m/s. EPA's AERSURFACE program was then used to derive surface characteristics for the stage 2 AERMET processing. The 2016 National Land Cover Database (NLCD) was used as input data to AERSURFACE. For the Primary PVGS site, two surface characteristic sectors were utilized, one from 70 to 173 degrees (to address the land surface characteristics around the adjacent PVGS plant), and the remaining sector addresses the natural land surfaces in the area. For the Sky Harbor met tower, the ADEQ processed AERSURFACE data was used. The definition of seasons was based on ADEQ's definitions for AERSURFACE processing of the Phoenix Sky Harbor airport data. An annual surface moisture setting of "average" was used. Monthly primary surface characteristics were processed.

To address issues with underprediction of the surface friction velocity (u*) during light wind, the ADJ_U* option was used in the stage 2 processing. The final valid AERMET meteorological data set has approximately 3% missing data which meets EPA requirements. Figure 2 presents the 10-meter wind rose for the PVGS data set.

Figure 3 - Wind Rose for PVGS Meteorological Data



Note: Data is for the 10-meter level wind data.

5.3 AERMOD Receptors

A receptor grid, or network, defines the locations of predicted air concentrations that are used to assess compliance with the relevant standards or guidelines. All coordinates used in the modeling are referenced to North American Datum 1983 (NAD83), Zone 12. The latest version of the AERMAP program was used to develop the model receptor grids. USGS National Elevation Data (NED) was used as the elevation data source for the AERMAP processing. The ADEQ Guidance for receptor grid placement is shown in Table 2.

Table 2– ADEQ Recommended Receptor Grid Coverage

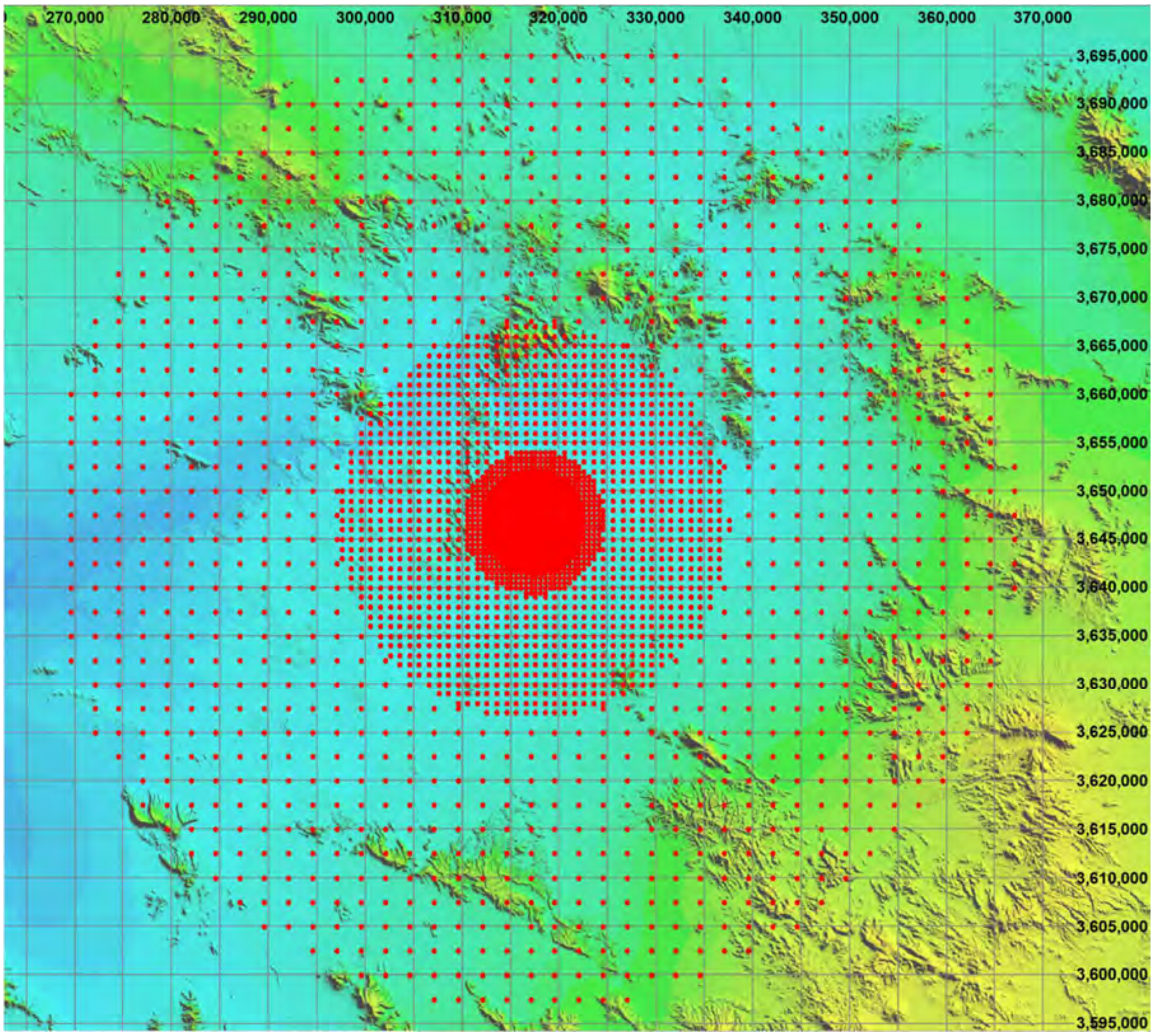
Type of Receptors	Suggested Receptor Spacing (meters)	Receptor Coverage Area
Tight	25	Along ambient air boundary (AAB)
Fine	100	From AAB to 1 km
Medium	200 - 500	From 1 km to 5 km away from AAB
Coarse	500 - 1,000	From 5 km to 20 km away from AAB
Very Coarse	1,000-2,500	From 20 km to 50 km away from AAB
Discrete	Not Applicable	Place at areas of concern such as nearby residences, schools, worksites or daycare centers

The main receptor network used for the air modeling consisted of the following grids:

- 25-meter spaced grid on the facility boundary,
- 100-meter spaced grid out to a distance of 1 km in all directions,
- 300-meter spaced grid from 1 km out to a distance of 5 km in all directions,
- 750-meter spaced grid from 5 km out to a distance of 20 km in all directions,
- 2000-meter spaced grid from 20 km out to a distance of 50 km in all directions.

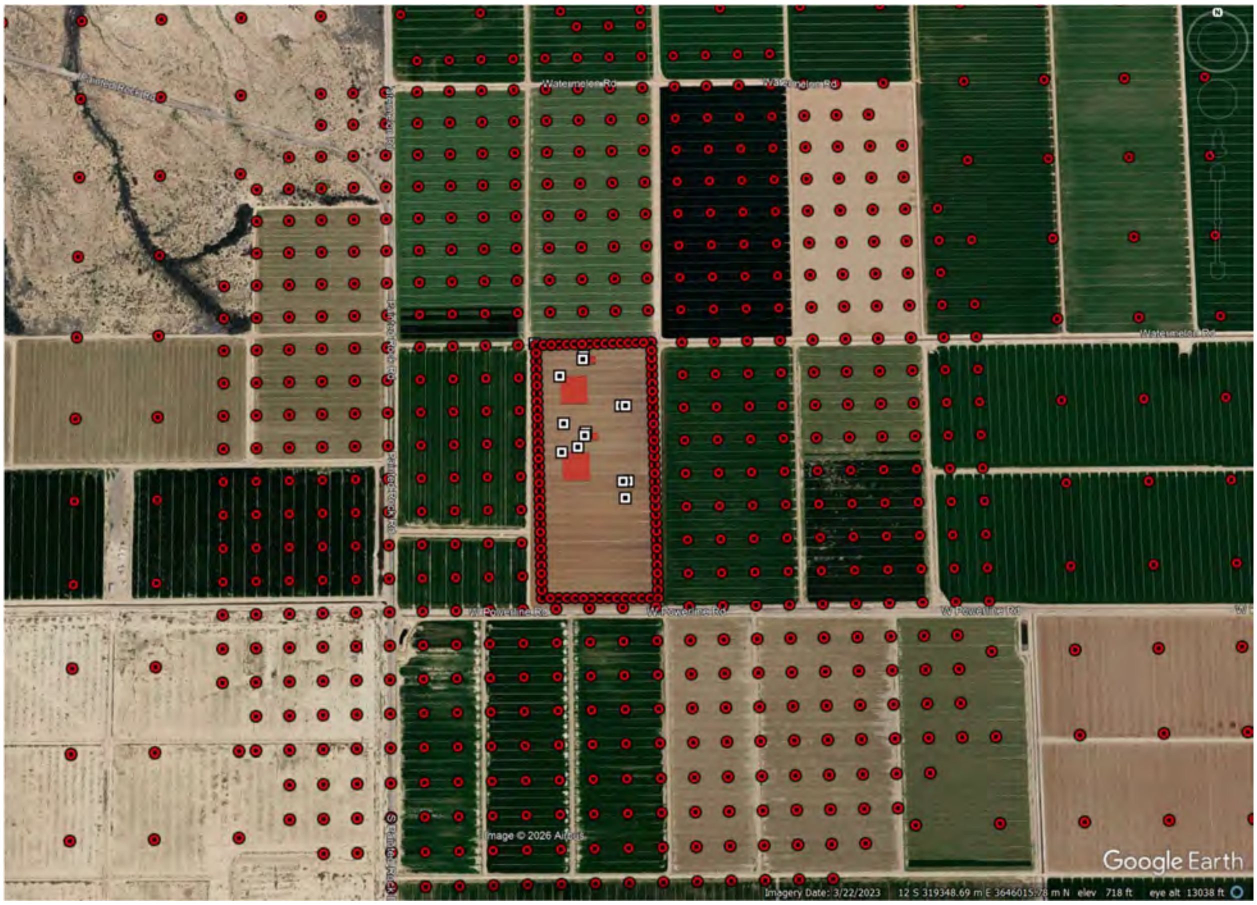
Figures 4 and 5 present views of the receptor data grids.

Figure 4- Full AERMAP Receptor Grid



Coordinates are UTM NAD 83 Zone 12. Red dots are receptors.

Figure 5- Close-in AERMAP Receptor Grid



Coordinates are UTM NAD 83 Zone 12. Red dots are receptors.

5.4 Urban versus Rural Dispersion Coefficients

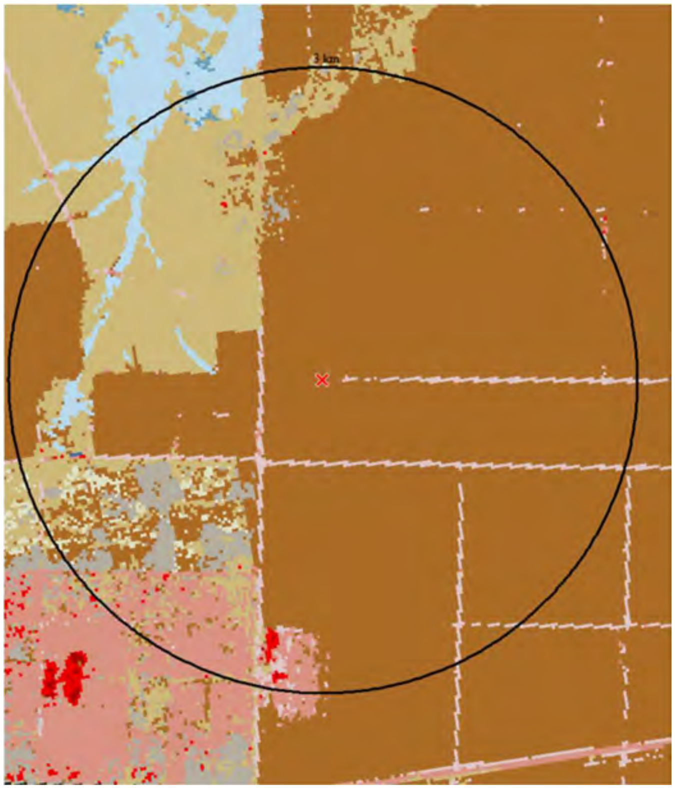
The AERMOD model allows the user to incorporate the effects of increased surface heating from an urban area on pollutant dispersion under stable atmospheric conditions. The selection of either rural or urban dispersion coefficients follows the procedures listed in Appendix W. The preferred Land Use Procedure classifies the land use within a 3km radius circle about the source using the meteorological land use typing scheme. If land use types I1, I2, C1, R2, and R3 account for 50 percent or more of the circle area, urban dispersion coefficients should be used. Sources located in areas defined as rural should be modeled using the rural dispersion parameters.

The land use typing scheme was used to determine the proper land use classification and AERMOD dispersion option for the Project. The USGS NLCD for 2016 for a 3 km radius centered on the plant presented in Figure 5 was reviewed. In accordance with Appendix W, an urban dispersion classification is to be used if the Auer land use types I1 (heavy industrial), I2 (light-moderate industrial), C1 (commercial), R2 (compact residential) and R3 (compact residential) account for 50% or more of the area within the 3 km radius around the site. The Auer land use classifications I1, I2, C1, R2 and R3 are no longer used by USGS, and these Auer classes correspond to the post-1992 NLCD land cover classes 23 (developed, medium intensity) and 24 (developed, high intensity), as shown in Table 3. Land cover classes 23 and 24 are shown as bright red and dark red areas in Figure 6.

Table 3- Land Cover Class Cross-Referencing

Auer – "Urban" Classes			NLCD 2011 Equivalent Classes		
Type	Use	Vegetation	Pervious	Use	No.
I1	Heavy Industrial	<5 %	0-20 %	Developed, high intensity	24
I2	Light Industrial	<5 %			
C1	Comm.	<15 %			
R2	Compact Residential	<30 %	20-50 %	Developed, medium intensity	23
R3	Compact Residential	<35 %			

Figure 6 – NLCD 2016 Land Use Categories near Project



The estimated total area for land cover classes 23 and 24 (bright and dark red areas) within the 3km circle in Figure 6 is a small fraction of the total area within the 3 km circle. Therefore, the area is designated as "rural" and the AERMOD RURAL modeling option was used.

5.5 GEP and Building Downwash

AERMOD can account for building downwash effects. The stack locations, stack heights, and structure locations and dimensions at the Project were input to EPA's "Building Profile Input Program – PRIME" (BPIP-PRIME) computer program. BPIP-PRIME processes this data in two steps. The first step determines and reports on whether a stack meets Good Engineering Practice (GEP) requirements and is subject to wake effects from a structure or structures. The second step calculated the "equivalent building dimensions" if a stack is influenced by structure wake effects in a format that is accepted by AERMOD. Since some stacks at the Project are influenced by wake effects, the BPIP-PRIME output for those stacks was input to the AERMOD model input file. Given that the heights of the proposed stacks are less than the de-minimus GEP height of 65 meters, the proposed stacks meet GEP requirements.

5.6 Modeling of NO_2 Impacts

The majority of NO_X emissions from combustion sources are in the form of nitric oxide (NO), whereas EPA has established air quality standards for NO_2. Therefore, a methodology must be used to convert model estimates of ambient NO concentrations into equivalent ambient NO_2 concentrations. The ARM2 ratio method option in AERMOD was used to account for the ambient conversion of emitted NO_X to ambient NO_2. In accordance with the EPA's GAQM, the minimum ARM2 ratio was set to 0.5 and the maximum ratio was set to 0.9 to result in a conservative analysis.

5.7 $PM_{2.5}$ Secondary Impact Analysis

The Project triggers PSD-review for $PM_{2.5}$, and the $PM_{2.5}$ air quality analysis followed the procedures described in EPA's "*Guidance for Ozone and Fine Particulate Matter Permit Modeling*", July 29, 2022 (herein referred to as the "Final Ozone and PM Guidance"). Because the Project emission increases of both direct $PM_{2.5}$ emissions and NO_X precursor emissions are above the PSD Significant Emission Rates, the $PM_{2.5}$ analysis for the Project is a "Case 2" analysis as described in the EPA Final Guidance. Case 2 analyses require the Project direct $PM_{2.5}$ emissions to be modeled using AERMOD, and the Project secondary emissions of NO_X and SO_2 (i.e., the "holistic" approach) to be evaluated using the Tier 1 methodology (Modeled Emission Rates of Precursor or "MERPs" methodology) to determine the Project's $PM_{2.5}$ total impacts.

The MERPs methodology uses empirical relationships between precursors and secondary $PM_{2.5}$ formation derived from photochemical grid modeling studies; it provides a simple way to calculate the maximum secondary $PM_{2.5}$ impacts from the NO_X and SO_2 precursor emission rates. MERPs have been derived by EPA for various areas of the country. The MERPs used for this secondary $PM_{2.5}$ impacts analysis were taken from EPA's "MERPs VIEW Qlik" webpage that provides access to EPA's hypothetical single source modeled impacts of $PM_{2.5}$ to support PSD permit modeling analyses. MERPs are provided for La Paz County, Arizona, which is representative of the Project location, and the lowest MERPs (which results in the highest predicted impact) for either 10 or 90 meter stack heights and 500 tpy emissions or less were used in the analysis. The daily $PM_{2.5}$ MERP NO_X value is 15,260 tpy and for SO_2 the value is 1,918 tpy. The annual $PM_{2.5}$ MERP NO_X value is 243,487 tpy and for SO_2 the value is 31,245 tpy. Given the Project emission increases of 327 tpy of NO_X and 21 tpy of SO_2, the calculated 24-hr secondary $PM_{2.5}$ impact is 0.02 $\mu g/m^3$ and the calculated annual secondary $PM_{2.5}$ impact is 0.002 $\mu g/m^3$. These values were considered in the Project's modeling analyses for $PM_{2.5}$, although both secondary formation concentrations are so low that they are within the rounding error of the primary $PM_{2.5}$ modeled concentrations.

5.8 $PM_{2.5}$ SILs Verification

In EPA's 2018 "Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program" (herein referred to as the SILs Guidance), EPA discusses developments regarding the use of $PM_{2.5}$ SILs after the January 22, 2013, the U.S. Court of Appeals for the District of Columbia Circuit decision. EPA does not interpret the court's decision to preclude the use of SILs for $PM_{2.5}$ as part of a demonstration that a source will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS. However, to ensure that PSD permitting decisions meet the requirements of the CAA, permitting authorities that use SILs for $PM_{2.5}$ must ensure that they apply the SILs on a case-by-case basis and in a manner that is consistent with the court's decision and the SILs Guidance.

The SILs are used both to define when a cumulative air quality analysis is required, and in a cumulative analysis of multiple sources to determine which sources are culpable for any NAAQS or PSD increment violations (i.e., a "culpability analysis"). For this air quality analysis, the $PM_{2.5}$ SILs are used only to determine when a cumulative analysis is required. EPA's SILs Guidance states "(p)ermitting authorities may elect to use the SIL values reflected in this guidance in a preliminary (single-source) analysis that considers only the impact of the proposed source in the permit application on air quality to determine whether a full (or cumulative) impact analysis is necessary". Based on this guidance, the $PM_{2.5}$ SILs are acceptable for use in this air quality analysis.

ADEQ modeling guidance recommends that the Permit applicant should determine whether a substantial portion of the NAAQS has already been consumed by evaluating background concentrations against the respective $PM_{2.5}$ NAAQS. If the source impact is below the applicable SIL and the difference between the NAAQS and the measured $PM_{2.5}$ background in the area is greater than the SIL, a full (cumulative) impact analysis can be exempted.

Background $PM_{2.5}$ monitoring data have been identified in Section 3.4 of this report, and the data is summarized along with the NAAQS and SILs in Table 4. This data indicates that the difference between the NAAQS and existing $PM_{2.5}$ air quality concentrations is greater than the $PM_{2.5}$ SILs. Therefore, there is adequate headroom between the existing air quality and the NAAQS to permit the use of the SILs for the modeling analyses.

Table 4– $PM_{2.5}$ Background Concentrations, NAAQS, and SILs

	NAAQS	Existing Air Quality	Difference between NAAAQS and Existing	SIL
$PM_{2.5}$ 24-hr	35	19.3	15.7	1.2
$PM_{2.5}$ Annual	9	7.1	1.9	0.2

Note: All values are expressed in units of ug/m3.

5.9 Source Characteristics

This section describes how the Project emission sources were characterized for modeling. The Project emission sources were modeled as POINT sources in AERMOD, as each emission unit exhausts vertically through stacks without any obstructions. Attachment A presents a plot plan of the layout of the new emission sources and structures at the facility as input into the AERMOD model.

The Permit Application contains detailed information on the Project hourly and annual emissions, considering both normal operation and startup/shutdown emissions. The normal emissions are based on the maximum rated heat input, the proposed BACT emission limits, and the fuel use limits.

Because emission rates and stack parameters for CTs can vary over a range of operating conditions, the modeling analysis must consider various operating load scenarios. The modeling analysis considered various operating load cases for the new turbines, which are calculated for over twenty combinations of ambient temperature, operating load, duct burner firing, and evaporative cooler status. It would be cumbersome to model each of these cases separately, therefore the data was grouped in operating load ranges (100% with duct burner, 100%, 75%, 50%, and minimum operating loads). For each of these five load ranges or "scenarios", the minimum stack flow and exhaust temperature across all ambient temperatures at that load were modeled with the maximum emission rates at that load. This results in a simplified yet conservative load screening analysis.

The NO_X and CO emission rates are greatest during startup operations, therefore for the NO_X and CO modeling the minimum load stack parameters were modeled along with the startup emission rates. Additional "compliance margin" was added to the NO_X and CO startup emission rates to calculate the final modeled maximum 1-hr rates; the modeled NO_X hourly rate is 300 lb/hr and the CO rate is 1500 lb/hr. As will be shown later, these modeled 1-hr emission rates do not cause or contribute to an exceedance of any NAAQS or PSD increment. In fact, the Project CO impacts are below the SILs, even using this higher modeled CO emission rate.

The emissions for PM_{10}, $PM_{2.5}$, and SO_2 do not increase during startups and are a function of the fuel flow (i.e., heat input rate); the emissions of these pollutants for the five load scenarios were calculated using the highest heat input rates for each load scenario.

Each of these five load scenarios was modeled, and the load scenario with the highest ambient impact was used for the subsequent SIL, NAAS, and PSD increment modeling.

5.10 Load Screening Results

Attachment A presents the stack parameters and emission rates that were used in the load screening analysis, along with the AERMOD results ("highest-first-high" concentrations for a single CT across the complete 5-year meteorological data set for each load scenario). These results indicate that the startup minimum load condition for NO_X and CO results in the maximum impacts for those pollutants, while the

100% with duct burner load scenario results in the highest impacts for PM_{10}, $PM_{2.5}$, and SO_2. These worst-case impact scenarios were used for all subsequent short-term modeling analyses. The annual impact analyses used the annual emission rates along with 100% load stack parameters.

5.11 PSD Class II SIL Modeling Results

The first step in the PSD modeling analysis is the significant impact analysis, which estimates ambient concentrations resulting from the Project emission increases. The Project-only impacts are summarized in Table 5.

All Project impacts are below the SILs except for the 1-hr NO_2 impacts, and the 24-hr and annual $PM_{2.5}$ impacts. Therefore, a cumulative NAAQS analysis is required for these pollutants and averaging intervals, and a cumulative PSD increment analysis is required for the same pollutants and averaging intervals except 1-hr NO_2 (there are no 1-hr NO_2 PSD increments that have been established).

Table 6 also presents the SMCs, as discussed in Section 3.1 of this report. The NO_2, CO, PM_{10}, and SO_2 Project impacts are below the SMCs, therefore pre-construction air quality data is not required for these pollutants.

Table 5 – Significant Impact Modeling Results

Pollutant	Avg Period	Maximum Modeled Impact (ug/m3)	Significant Impact Level (ug/m3)	Exceeds SIL?	Significant Impact Area (SIA km)	Significant Monitoring Conc. (SMC) ug/m3
NO_2	1-hr	133	7.5	Yes	50	N/A
	Annual	0.9	1	No	N/A	14
$PM_{2.5}$	24-hr	2.4	1.2	Yes	1.6	N/A
	Annual	0.38	0.13	Yes	2.0	N/A
PM_{10}	24-hr	3.7	5	No	N/A	10
	Annual	0.4	1	No	N/A	N/A
CO	1-hr	1439	2000	No	N/A	N/A
	8-hr	383	500	No	N/A	575
SO_2	1-hr	2.1	7.8	No	N/A	N/A
	3-hr	1.2	25	No	N/A	N/A
	24-hr	0.4	5	No	N/A	13
	Annual	0.08	1	No	N/A	N/A

5.12 PSD Class II NAAQS Modeling and Results

A cumulative NAAQS analysis is required for the 1-hr NO_2 and 24-hr and annual $PM_{2.5}$ pollutants/averaging intervals. The cumulative analysis expands the Project-only modeling by adding other nearby sources to the Project emission sources. The impacts of more distant sources and other sources not explicitly modeled are accounted for by adding monitored air quality data (i.e., background concentrations) to the model predicted concentrations. The resultant total concentrations are then compared to the NAAQS.

In Section 8.3.3 of EPA's GAQM, EPA provides guidance on the nearby sources to include in the cumulative NAAQS analysis. EPA states:

> *The number of nearby sources to be explicitly modeled in the air quality analysis is expected to be few except in unusual situations. In most cases, the few nearby sources will be located within the first 10 to 20 km from the source(s) under consideration. Owing to both the uniqueness of each modeling situation and the large number of variables involved in identifying nearby sources, no attempt is made here to comprehensively define a "significant concentration gradient". Rather, identification of nearby sources calls for the exercise of professional judgment by the appropriate reviewing authority.*

An important consideration for the development of the nearby source inventory is the size of the Project Significant Impact Area (SIA). The SIA defines the maximum distance for which a project's impacts are above the SILs. The Project's SIA are 2 km or less for the $PM_{2.5}$ impacts and 50 km for the 1-hr NO_2 impact (the larger 1-hr NO_2 SIA is a result of the low SIL value and use of the highest 1-hr concentration over 5 years of meteorological data). While the historical approach for deterministic NAAQS has been to evaluate all sources within the SIA for possible explicit modeling, EPA has noted in the probabilistic 1-hr NO_2 NAAQS modeling guidance that "inclusion of all sources within 50 kilometers of the project location, the nominal distance for which AERMOD is applicable, is likely to produce an overly conservative result in most cases", and that "the emphasis on determining which nearby sources to include in the modeling analysis should focus on the area within about 10 kilometers of the project location in most cases".

Given the above EPA guidance, the $PM_{2.5}$ and NO_X emissions sources within 20 km of the Project were identified. The only source within 20 km is the Aluminum Dynamics (AD) facility, located 16 km distant from the facility. In addition, the Gila River Power Plant (GRPP) was identified at a distance of 24 km from the Project. Additional cumulative sources initially considered included the Mesquite, Arlington Valley Energy, and Redhawk power plants, however these sources are located 45 km to the north; based on EPA guidance quoted above, these distant sources were not included in the cumulative modeling. The AD and GRPP sources were screened using the common "20D" procedure to identify sources that can be excluded from cumulative modeling because they are not anticipated to impact receptors in the Project's SIA. Under the "20D" screening procedure, sources are excluded if the facility's emissions (tpy) are less than 20 times the distance (km) from the proposed Project. The ADEQ permitted PTE emissions of the AD facility are 94 tpy for NO_X and 52.2 tpy of $PM_{2.5}$. Given a distance of 16 km, the Q/D ratio for both of these pollutants is significantly less than 20 and this source was excluded for cumulative modeling. The GRPP PTE are 720 tpy for NO_X and 402.5 tpy of $PM_{2.5}$. Given a distance of 24 km, the Q/D ratio for both of these pollutants is greater than 20 and this source was included in the cumulative modeling. The GRPP was permitted in 2001 and began operation before the $PM_{2.5}$ PSD baseline date of May 10, 2015. Therefore, the GRPP was not included in the $PM_{2.5}$ PSD increment analyses.

The stack parameters and emission rates modeled for all cumulative emission sources are presented in Attachment A.

Table 6 presents the results from cumulative NAAQS analysis which demonstrates that the Project impacts, in combination with other nearby sources, are below the NAAQS.

Table 6 – NAAQS Modeling Results

Pollutant	Maximum Modeled Impact (μg/m³)	Background Concentration (μg/m³)	Total Concentration (μg/m³)	NAAQS	Percent of NAAQS
NO_2 1-hr	106	60	165.5	188	88%
$PM_{2.5}$ 24-hr	1.8	19.3	21.1	35.0	60%
$PM_{2.5}$ Annual	0.4	7.1	7.5	12.0	62%

5.13 PSD Class II PSD Increment Modeling and Results

Table 7 presents the results from cumulative PSD increment analysis which demonstrates that the highest-2nd-high 24-hr impact and the highest annual impact are below the $PM_{2.5}$ PSD Increments.

Table 7 – Class II PSD Increment Modeling Results

Pollutant	Maximum Modeled Impact (μg/m³)	PSD Increment (μg/m³)	Percent of Increment
$PM_{2.5}$ 24-hr	2.7	9	30%
$PM_{2.5}$ Annual	0.4	4	10%

5.14 Ozone Impact Assessment

EPA's *Guidance for Ozone and Fine Particulate Matter Permit Modeling* (EPA-454/R-22-005, July 2022) describes the PSD ozone NAAQS compliance demonstration that is required when a proposed project's NO_X or VOC emissions exceed the PSD Significant Emission Rates (SERs). EPA has developed a two-tiered approach for conducting a single-source ozone impact analysis for PSD permitting. The Tier 1 ozone assessment relies on the Modeled Emission Rate Precursors (MERPs) methodology. If a Tier 1 MERPs analysis cannot demonstrate that the Project will either (1) result in ozone impacts below the applicable ozone SIL or (2) result in combined Project and representative background ozone concentrations below the ozone NAAQS, a more refined Tier 2 ozone impact analysis may be performed.

A Tier 1 ozone impact analysis was performed for the Project. The MERPs used were taken from EPA's "MERPs VIEW Qlik" webpage. MERPs are provided for La Paz County, Arizona, which is representative of the Project location, and the lowest MERPs (which results in the highest predicted impact) for either 10 or 90 meter stack heights and 500 tpy emissions or less were used in the analysis. The 8-hr ozone MERP NO_X value is 214 tpy and the VOC value is 24,649 tpy. Given the Project emission increases of 327 tpy of NO_X and 106 tpy of VOC, the calculated 8-hr ozone impact is 1.5 ppb; this is the maximum MERP predicted ozone impact which occurs within approximately 10 km of the Project location. This impact exceeds the ozone SIL of 1.0 ppb, therefore a cumulative Tier 1 ozone analysis was conducted using data from the nearest representative ozone background monitor, the Buckeye monitor operated by Maricopa County. The 2023-2025 ozone design concentration at the Buckeye monitor is 0.0677 ppm; when combined with the Project impact, the resulting total ozone concentration is 0.0692 ppm, which is below the ozone NAAQS of 0.07 ppm. Therefore, the Tier 1 cumulative analysis demonstrates the Project will not cause or contribute to a violation of the ozone NAAQS.

Given the fact that the 2015 8-hr ozone NAA is located 13 km to the east/northeast of the Project, additional analyses were performed to determine the Project's ozone impacts specifically in the NAA. When designating a NAA area, EPA includes both the area that is violating the standard, and also those nearby areas that do not show violations but may contribute to violations in the violating area. In EPA's *Phoenix-Mesa and Yuma Nonattainment Areas Intended Area Designations for the 2015 Ozone National Ambient Air Quality Standards Technical Support Document (TSD)*, EPA states:

> "The EPA must designate as nonattainment any area that violates the NAAQS, and any nearby areas that contribute to the violation in the violating area. (T)here are 15 violating monitors that are located in the area of analysis. The violating monitors are located in or near the city of Phoenix in Maricopa County as well as bordering areas in northern Pinal County and western Gila County. Monitors that are attaining the 2015 ozone NAAQS are generally located in the western and northwestern portion of the Phoenix Metro area within Maricopa County. Additional attaining monitors are located in the western and southern portions of Pinal County, near the cities of Casa Grande and the Pinal-Pima County border, respectively."

Based on EPA's designation report, the violating portion of the Maricopa ozone NAA includes the central Phoenix urban core as well as bordering suburbs to the east and north. The non-violating portion of the NAA includes the western and northwestern portion of the Phoenix Metro area within Maricopa County. The Buckeye ozone monitor is located 56 km from the Project in the non-violating portion of the NAA, and current monitoring data at that station still demonstrates attainment at this location. The nearest ozone monitor within the violating portion of the NAA is the West Phoenix monitor, located approximately 100 km distant from the Project site. The NO_X MERP value at a 50 km distance is approximately 616 tpy and given the Project's emissions the Project ozone impact at the Buckeye monitor is 0.5 ppb. The NO_X MERP value at a 100 km is 1,456 tpy and given the Project's emissions the Project ozone impact at the West Phoenix violating monitor is approximately 0.2 ppb. Therefore, when the distant-dependent MERP values are used, the Tier 1 ozone impacts in both the violating and non-violating portions of the NAA are below the ozone SIL of 1ppb.

Even though the Tier 1 analysis demonstrates the Project will not "cause or contribute" to ozone NAAQS violations, APS elected to perform a more refined Tier 2 analysis of Project ozone impacts within the Phoenix ozone NAA for the purpose of demonstrating that Project impacts throughout the entire NAA are less than the 1 ppb ozone SIL. This Tier 2 analysis supplements the Tier 1 assessment and provides additional evidence that the Project will not cause or contribute to a violation of the ozone NAAQS. Attachment B presents the Tier 2 analysis, which demonstrates that the Project ozone impacts are below the ozone SIL throughout the NAA.

In summary, both Tier 1 and Tier 2 analyses demonstrate that the Project will not cause or contribute to a violation of the ozone NAAQS in either the attainment area or the Phoenix ozone NAA.

6.0 Additional Impacts Analysis

An additional impact analysis is required for pollutants that trigger PSD review. The purpose of this analysis is to assess the potential impact the proposed project will have on visibility, soils, and vegetation, as well as the impact of general commercial, residential, and industrial growth associated with the proposed project.

6.1 Analysis on Vegetation and Soils

The analysis of NO_X, CO, PM_{10}, and $PM_{2.5}$ impacts on vegetation and soils of commercial or recreational value was based on an inventory of vegetation and soils in the Project area, and a comparison of AERMOD predicted air quality impacts of the Project to various effects thresholds.

The Project is at an elevation of approximately 720 feet above mean sea level and located in a broad valley historically used for agriculture. The primary land use continues to be agricultural, and two irrigation canals owned by the Palomas Irrigation District cross the property from east to west. Painted Rock Dam and Reservoir, a U.S. Army Corps of Engineers (USACE) flood control facility, is approximately five miles north of the Project site. Adjacent lands to the north, east, and west are predominately agricultural with some residential communities. Land uses beyond adjacent agricultural uses to the south are mostly open desert. The Project site is not in any federally proposed or designated critical habitat areas.

The soil characteristics for the Project site include Mohall and Wellton loams which are considered prime farmland soils if irrigated. The Project site has native vegetation characteristics of the Lower Colorado River Valley subdivision of the Sonoran Desert scrub biome; however, the entire project site has previously been mostly cleared of native vegetation to support row crops. Google Earth imagery dating back to 1984 shows that this land has been used for agriculture since at least that time. Due to the extensive past land manipulation of active farms, native plant species are limited in the Project site. Common plant species associated with the Lower Colorado River Valley generally consist of creosote, white bursage, ironwood, and blue palo verde. It is anticipated that no native trees or cacti would be removed as part of this Project.

The air quality impacts from the Project were compared to vegetation and soils threshold impact criteria in EPA's *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals*, December 12, 1980, EPA 450/2-81-078. This document contains screening levels for NO_2 and CO impacts. The CO screening threshold for sensitive vegetation is listed as 1000 ppm (1,200,000 µg/m3) for a 1-week exposure. The NO_2 screening threshold for sensitive vegetation is listed as 2 ppm (3,760 µg/m3) for a 4-hour exposure. The Project CO and NO_2 impacts are orders of magnitude lower than these thresholds. In addition, because the Project combusts only natural gas, there are no appreciable emissions of metals and the Project metals impacts are far below any listed screening thresholds for soils and vegetation.

Information on the sensitivities of vegetation to NO_2 ambient concentrations is also found in EPA's "Air Quality Criteria for Oxides of Nitrogen, Summary of Vegetation Impacts" Volume II, August 1993 (EPA

600/8-91/049bF). For susceptible plant species, 1-hr NO_2 exposures to approximately 7,500 μg/m3 can cause 5% foliar injury. Once again, the Project NO_2 impacts are orders of magnitude lower than this threshold.

In summary, based on a comparison of Project air quality impacts to various screening thresholds, it can be concluded that the Project will not have an adverse impact on nearby soils and vegetation.

6.2 Analysis on Visibility

A Class II area visibility analysis was performed for the Maricopa County park that is closest to the Project, the Buckeye Hills Regional Park. VISCREEN was used to assess visibility impacts at this location. Note that there are no established adverse effects thresholds for Class II visibility analyses.

The VISCREEN model is a screening technique used to estimate the mass of pollutants in the atmosphere and its ability to scatter or absorb light and, therefore, to affect visibility. The VISCREEN model calculates rudimentary scattering and absorption coefficients, and these values are compared to screening threshold levels to determine the potential magnitude and type of coherent plume visibility impairment. Two measures of potential plume effects are used. One is a measure of plume contrast, which is the change in light extinction coefficient between views against a background feature (either sky or terrain) and views against the plume. The other measure is delta E, the total color contrast, which takes into account plume intensity, color, and brightness. If the plume is brighter than its background, it will have a positive contrast. If the plume is darker than its background, it will have a negative contrast. VISCREEN assumes that a terrain object is black, which maximizes the contrast. VISCREEN was run with simple "worst-case" meteorology, referred to as a "Level 1" analysis.

The emissions used for the VISCREEN analysis are based on both CTs operating at 100% load concurrently. Other VISCREEN inputs include the default particle characteristics, wind speed of 1 m/sec and worst-case daytime stability class of E, and an estimated existing background visual range in the Phoenix area of 90 km. Table 8 presents the VISCREEN Class II analysis results for "Inside the Class II area". There are no specific impact thresholds to compare against these Class II visibility modeling results, however these results do not exceed recommended Class I area thresholds.

Table 8 - VISCREEN Class II Visibility Analysis Results

Parameter	Buckeye Hills Park
Distance to Park Boundary (km)	45
Maximum Delta E	1.4
Maximum Contrast	0.014

6.3 Associated Growth and Secondary Emissions Analysis

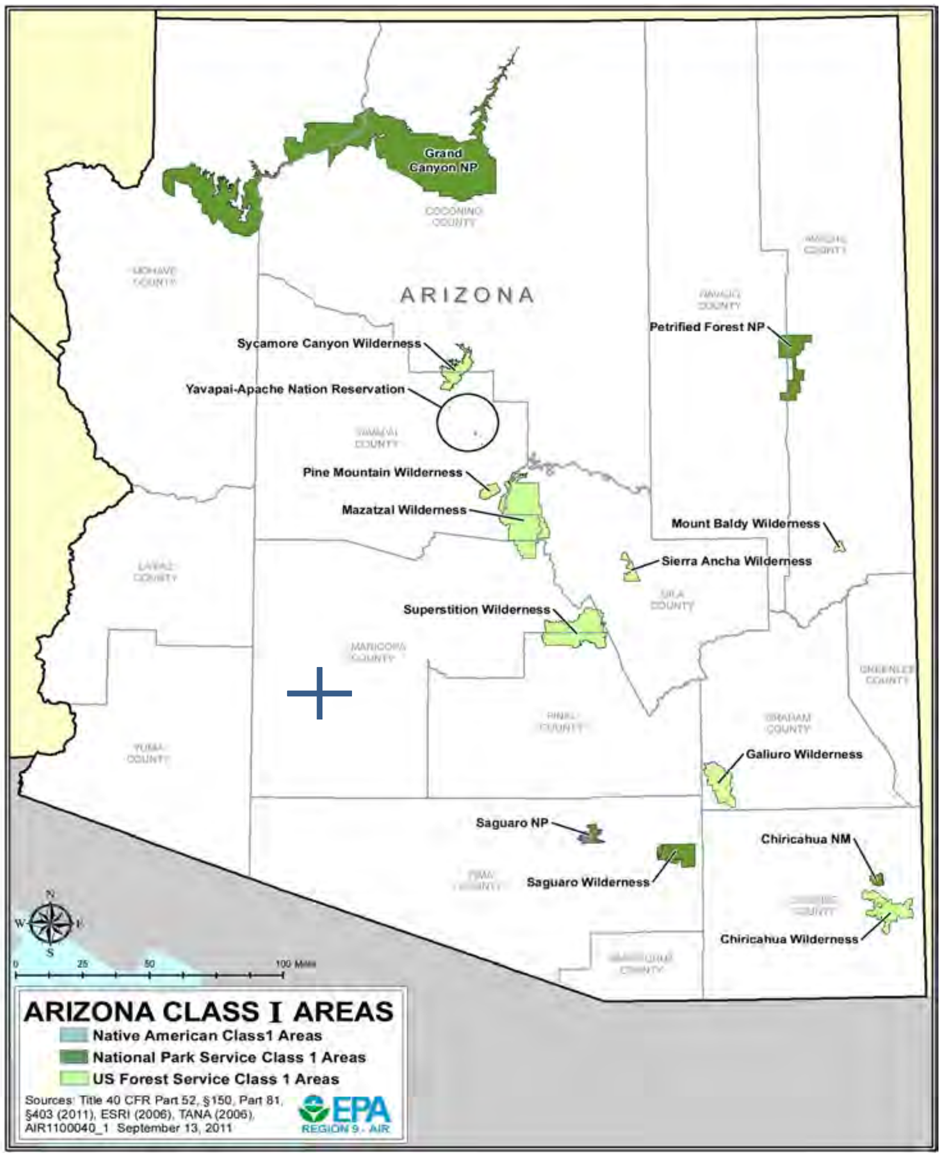
The emissions resulting from residential, commercial, and industrial growth associated with, but not directly a part of the project, must also be considered when conducting the air quality analysis. Given the availability of construction services and employees from the nearby greater Phoenix area, the Project will not have a significant impact on the local population growth, nor will local municipal services be adversely impacted by this Project. Therefore, the Project is not expected to have a measurable effect on the residential, commercial, or industrial growth of the area.

7.0 Class I Area Analyses

The PSD regulations require that permitting agencies should notify the Federal Land Managers (FLMs) of a project which may affect a Class I area (i.e., are generally located within 100 km of a Class I area). The permit applicant may be required to perform a Class I PSD Increment analysis and an Air Quality Related Values (AQRVs) analysis. The FLM's *Air Quality Related Values Work Group (FLAG) Phase I Report – Revised* (FLAG 2010) provides guidance on methodologies for conducting Class I air quality impact analyses.

Figure 7 presents a map showing the locations of Class I areas within Arizona relative to the Project location (shown as a blue cross). None of these Class I areas are within 100 km of the Project location. The closest Class I area is the Superstition Wilderness area located 148 km distant.

Figure 7 – Locations of Class I Areas relative to the Project



7.1 Class I AQRV Analysis Requirements

The FLAG 2010 guidance has developed an initial screening method that exempts a project from AQRV impact analysis and review based on its annual emissions and distance from a Class I area. The FLMs will consider a source locating greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if the total SO_2, NO_X, PM_{10}, and H_2SO_4 annual emissions in tpy, divided by the distance (in km) from the Class I, area (Q/D) is 10 or less. The Agencies would not request any Class I AQRV impact analyses from such sources.

The Project is a base load facility and the annual tpy emissions reflect 100% capacity factor. Therefore, the Project PTE annual emissions in tpy can be used in the Q/D analysis. Given annual tpy emissions of 325 for NO_X, 21 for SO_2, 159 for PM_{10}, and 5 for sulfuric acid mist, the total combined emission rate is 510 tpy, and the distance to the nearest Class I area is 148 km. The calculated Q/D value is 3.4, which is significantly less than the FLAG AQRV analysis threshold of 10. Therefore, AQRV analyses will not be required for the Project.

7.2 Class I SIL Analyses

The Project triggers PSD review for the criteria pollutants NO_2, CO, PM_{10}, and $PM_{2.5}$. Class I PSD increments and SILs have been established for NO_2, PM_{10}, and $PM_{2.5}$, as shown in Table 9. Therefore, a Class I area significant impact analysis was performed for these pollutants and averaging intervals.

Table 9 – Class I SILs and PSD Increments

Pollutant	Avg Period	PSD Class I Increment (µg/m^3)	Class I Significant Impact Level (µg/m^3)
NO_2	Annual	2.5	0.1
$PM_{2.5}$	24-hr	2.0	0.27
	Annual	1.0	0.05
PM_{10}	24-hr	8	0.3
	Annual	4	0.2

When performing a Class I increment analysis for Class I areas located more than 50 km from the source, EPA's GAQM recommends that AERMOD be used to determine the Project-only significant impacts at a distance of 50 km from the source (the maximum range for which AERMOD can adequately estimate air quality impacts). Given the locations of Class I areas in Arizona, the 50 km receptor ring was limited to the directions of 18 through 178 degrees (north-northeast through southerly directions) , to capture the directions to all the Class I areas in Arizona (except Grand Canyon National Park, which is located 350 km distant from the Project and will not be impacted by the Project because of this great distance). If this analysis at 50 km indicates there are no significant impacts at that distance, then further assessment of the Class I PSD increments is not necessary. Given the fact that transport of Project emissions to the nearest Class I area, the Superstition Wilderness area, travels across the central Phoenix Valley, the Sky Harbor meteorological data set was selected as the most representative meteorological data set for the transport from the Project site to the closest Class I area.

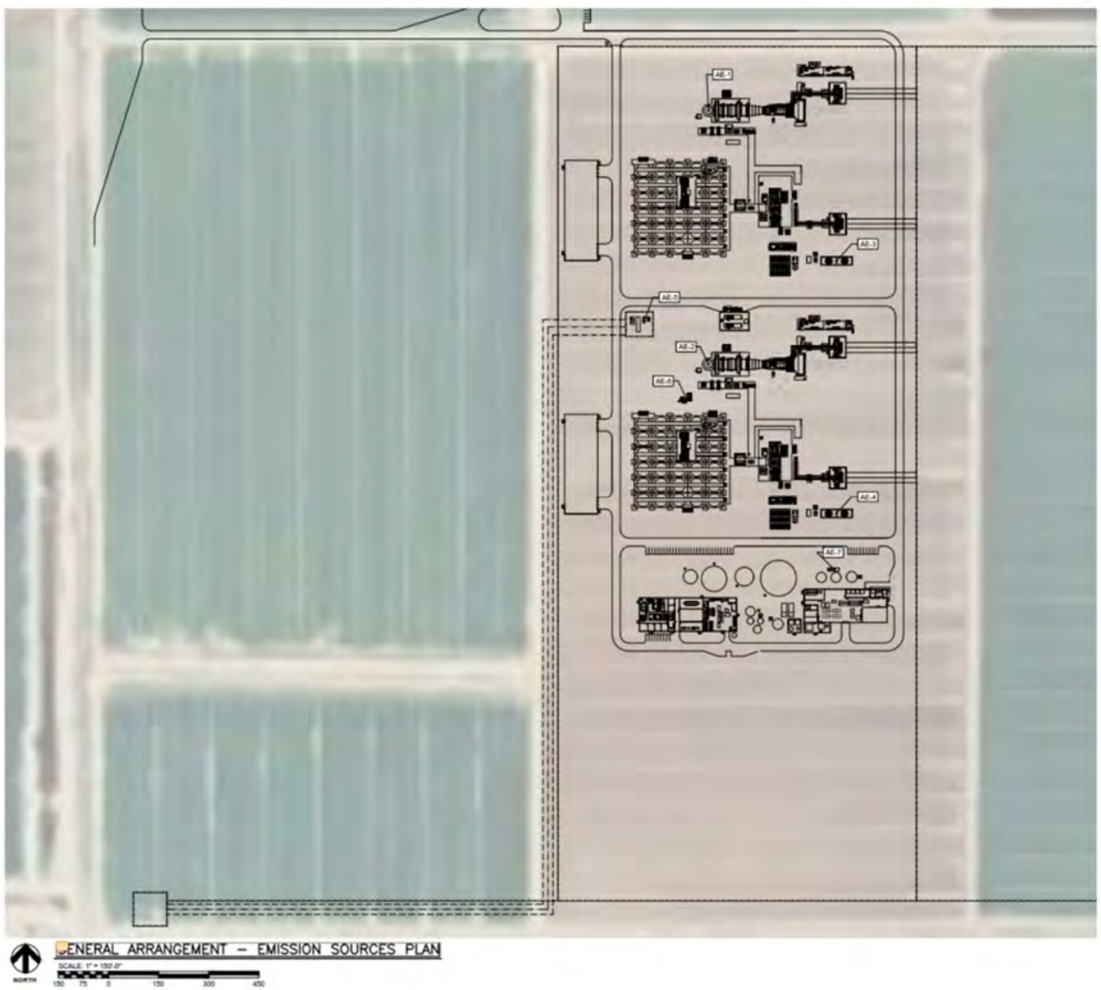
Table 10 presents the results from the Class I screening analysis. The $PM_{2.5}$ impacts include the maximum MERP-calculated secondary formation $PM_{2.5}$ concentrations (which are very conservative, because a more accurate calculation would use distance-adjusted MERPs at 100km or beyond). All predicted impacts are below the Class I SILs; therefore, no additional Class I PSD increment modeling is necessary.

Table 10 – Class I Screening Modeling Results

Pollutant	Avg Period	Maximum Predicted Impacts (µg/m3)	Class I Significant Impact Level (µg/m^3)
NO_2	Annual	0.02	0.1
$PM_{2.5}$	24-hr	0.23	0.27
	Annual	0.014	0.05
PM_{10}	24-hr	0.19	0.3
	Annual	0.012	0.1

Attachment A – Plot Plan and Emission and Stack Information

Facility Plot Plan



AIR EMISSION (AE) SOURCES	
MARK	DESCRIPTION
AE-1	CC HRSG STACK UNIT 1
AE-2	CC HRSG STACK UNIT 2
AE-3	WET COOLING TOWER UNIT 1
AE-4	WET COOLING TOWER UNIT 2
AE-5	FUEL GAS HEATER 1
AE-6	CCGT AUXILIARY BOILER
AE-7	DIESEL FIRE PUMP

NOTES:

1. LAYOUT IS CONCEPTUAL AND INTENDED FOR DISCUSSION PURPOSES ONLY. NOT FOR CONSTRUCTION.

Emission and Stack Data used in Load Screening Analyses

Scenario	Source Description	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Stack Height (ft)	Temperature (F)	Exit Velocity (ft/s)	Stack Diameter (ft)	PM10 lb/hr	CO lb/hr	NO2 lb/hr	SO2 lb/hr
100DB	100DB	317385	3646915	720	165	172.7	58.8	23	28.5	21.4	35.2	2.85
100	100	317385	3646915	720	165	183.0	60.3	23	15.0	16.8	27.7	2.24
75	75	317385	3646915	720	165	183.6	51.2	23	11.8	13.0	21.4	1.77
50	50	317385	3646915	720	165	180.1	42.8	23	9.0	10.0	16.4	1.36
Min/SU	Min/SU	317385	3646915	720	165	178.2	37.0	23	6.9	1500	300	1.03

Load Screening Analysis Results

Scenario/Pollutant-Interval	NO2 1-hr	NO2 Annual	SO2 1-hr	SO2 3-hr	SO2 24-hr	SO2 Annual	PM10/PM25 24hr	PM10/PM25 Annual	CO 1-hr	CO 8-hr
100% Load + Duct B	10.2	N/A	**2.695**	**1.911**	**0.356**	**0.05963**	**1.42**	**0.2383**	8.1	2.4
100% Load	7.7	**0.188**	2.047	1.367	0.255	0.04231	0.68	0.1131	6.1	1.7
75% Load	6.2	0.175	1.862	1.428	0.269	0.03990	0.72	0.1070	5.5	1.7
50% Load	5.9	0.170	2.270	1.465	0.281	0.03913	0.74	0.1036	6.7	1.8
Min Load/Startup	**121.0**	N/A	1.957	1.351	0.262	0.03597	0.70	0.0955	**1129.0**	**347.2**

NOTE: The worst-case impact is highlighted in bold.

Project Emission and Stack Data used in SIL, NAAQS, and PSD Increment Analyses

Source ID	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Stack Height (ft)	Temperature (F)	Exit Velocity (ft/s)	Stack Diameter (ft)	PM10/PM25 lb/hr	NO2 lb/hr	CO lb/hr	SO2 lb/hr	PM10/PM25 tpy	NO2 tpy	SO2 tpy
CC1	317384	3647145	720	165	183	60	23	29	300.0	1500.0	2.85	79.06	161.22	21.01
CC2	317385	3646915	720	165	183	60	23	29	300.0	1500.0	2.85	79.06	161.22	21.01
AUXBLR	317365	3646884	720	50	300	8	4	0	3.3	3.6	0.05	0.23	1.67	0.03
CC1CT1	317498	3647008	720	10	105	32	7	0	0.0	0.0	0.00	0.03	0.00	0.00
CC1CT2	317513	3647008	720	10	105	32	7	0	0.0	0.0	0.00	0.03	0.00	0.00
CC2CT1	317500	3646779	720	10	105	32	7	0	0.0	0.0	0.00	0.03	0.00	0.00
CC2CT2	317515	3646780	720	10	105	32	7	0	0.0	0.0	0.00	0.03	0.00	0.00
DPHTR1	317324	3646956	720	35	150	14	3	0	0.5	1.8	0.03	0.99	2.17	0.12
FIREPUMP1	317506	3646729	720	12.2	880	77	1	0	0.1	2.9	0.01	0.02	0.34	0.00

Note: The CC1 and CC2 stack temperature and flow rate data is for the 100% load case.

Other Source data used in Cumulative Modeling

Source ID	Easting (X) (m)	Northing (Y) (m)	Base Elevation (ft)	Stack Height (ft)	Temperature (F)	Exit Velocity (ft/s)	Stack Diameter (ft)	PM25 lb/hr	NO2 lb/hr	PM25 tpy
GR01	341640	3649638	214	130	172	62	18	12	19.0	47.8
GR02	341640	33649684	214	130	172	62	18	12	19.0	47.8
GR03	341640	3649761	214	130	172	62	18	12	19.0	47.8
GR04	341640	3649807	214	130	172	62	18	12	19.0	47.8
GR05	341640	3649945	214	130	172	62	18	12	19.0	47.8
GR06	341640	3649991	214	130	172	62	18	12	19.0	47.8
GR07	341640	3650068	214	130	172	62	18	12	19.0	47.8
GR08	341640	3650114	214	130	172	62	18	12	19.0	47.8

Attachment B – Tier 2 Ozone Impact Analysis

Prepared for:

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Desert Sun Tier 2 Ozone Impacts Modeling Report

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Executive Summary

This report presents a Tier 2 ozone impact assessment prepared for the Arizona Public Service (APS) to support Prevention of Significant Deterioration (PSD) permitting for the proposed Desert Sun Generating Station (the Project), a new natural gas-fired combined-cycle facility to be located in Gila Bend, Arizona, approximately 10 miles (13 km) west of the western boundary of the Phoenix–Mesa 2015 8-hour ozone nonattainment area (NAA). Because the Project's nitrogen oxides (NOx) and volatile organic compound (VOC) emissions exceed PSD Significant Emission Rates (SERs), an ozone impact analysis is required under EPA's Guideline on Air Quality Models and related single-source ozone permitting guidance. Although a Tier 1 screening using Modeled Emission Rates for Precursors (MERPs) indicated a screening-level impact above the 1 ppb ozone Significant Impact Level (SIL) at the Project location, the Tier 1 cumulative check using representative monitored background ozone remained below the 2015 ozone National Ambient Air Quality Standard (NAAQS). To provide a more refined and spatially explicit demonstration within the NAA, APS elected to perform this Tier 2 photochemical grid model (PGM) evaluation focused on Project-attributable changes in Maximum Daily 8-hour Average (MDA8) ozone across the Phoenix–Mesa NAA.

The Tier 2 evaluation leveraged the Maricopa Association of Governments (MAG) CAMx-based ozone modeling platform originally developed for MAG's Clean Air Act (CAA) Section 179B(b) demonstration. The platform uses the Comprehensive Air Quality Model with Extensions (CAMx) with three nested horizontal domains (36/12/4 km) and 23 vertical layers. CAMx simulates the 2023 summer ozone season (April 1 through September 30, 2023) using the Carbon Bond 7 revision 1 (CB7r1) chemistry, WRF-based meteorology, and emissions inventories processed with the Sparse Matrix Operator Kernel Emissions (SMOKE) processing system. Initial and boundary conditions for the outer domain are based on the GEOS-Chem global model. Project emissions were incorporated as two combustion turbine point sources (Units U1 and U2) with stack parameters and hourly emissions supplied by RTPEnv and processed into model-ready inputs using SMOKE (including chemical speciation and temporal allocation consistent with the platform). A conservative "worst-case" daily operating scenario was assumed to maximize potential ozone impacts, combining full-load operation with startup and shutdown activity; the resulting daily-average precursor emissions for the combined turbines are 91 lb/hr NOx and 41 lb/hr VOC (with NOx conservatively rounded up to 95 lb/hr). Two CAMx scenarios were modeled: a Base Case representing existing conditions and a New Source Case identical to the Base Case except for the inclusion of the Project emissions. Project ozone impacts were quantified using a "brute force" approach that pairs space-and-time differences in MDA8 ozone between the New Source Case and Base Case (New Source minus Base). Impacts were evaluated for grid cells within the Phoenix–Mesa ozone NAA in a manner consistent with EPA's ozone permitting guidance for interpreting Tier 2 results and comparing source-attributable impacts to the 1 ppb SIL. The evaluation focused on impacts to the 4th highest MDA8 ozone concentrations, which are directly relevant to the ozone design value, while also considering additional rankings because ozone concentrations may exceed the NAAQS at higher-ranked values.

Key findings and conclusions are summarized below:

- Across the Phoenix–Mesa NAA, the modeled Project-attributable ozone impacts are below EPA's 1.0 ppb ozone SIL for the key regulatory comparison metrics evaluated, including the 4th-highest MDA8 concentrations.

- The maximum modeled Project impact within the NAA is 0.85 ppb (occurring on the fifth highest MDA8 concentrations), and all other ranked maximum impacts summarized in this report are below 1 ppb.
- Although modeled Base Case and New Source Case MDA8 ozone concentrations can exceed the ozone NAAQS at some NAA grid cells (reflecting regional conditions), the incremental change attributable to the Project remains below the SIL, indicating the Project's contribution is sufficiently small to be considered not meaningful for PSD purposes.
- Based on the Tier 2 CAMx results using conservative emissions assumptions and a known and accepted regional modeling platform, the Project is not expected to cause or contribute to an ozone NAAQS violation within the Phoenix–Mesa ozone NAA.

1.0 Introduction

RTP Environmental Associates, Inc. (RTPEnv) is assisting Arizona Public Service (APS) in permitting the proposed Desert Sun Generating Station (the Project), a new source of nitrogen oxides (NOx) to be located in Gila Bend, Maricopa County, Arizona. The Project will consist of two natural gas-fired combined-cycle combustion turbine electric generating units equipped with dry low-NOx combustors and selective catalytic reduction (SCR) for NOx control, and oxidation catalysts for carbon monoxide (CO) and volatile organic compound (VOC) control. The Project is proposed in an area classified as attainment or unclassified for all criteria air pollutants and approximately 10 miles (13 km) west of the western boundary of the Phoenix-Mesa 2015 8-hour ozone nonattainment area (NAA). Because the Project is outside the ozone NAA, it requires a Prevention of Significant Deterioration (PSD) permit. Ozone impacts for PSD permitting are typically assessed using Modeled Emission Rates for Precursors (MERPs)[1] as a Tier 1 demonstration that the source would have an insignificant effect on ozone concentrations. Given the Project's proximity to the Phoenix ozone NAA, RTPEnv retained Ramboll to conduct explicit photochemical grid model (PGM) modeling to estimate Project-related ozone impacts within the NAA.

The Maricopa Association of Governments (MAG) prepared a Clean Air Act (CAA) Section 179B(b)[2] retrospective demonstration concluding that the Phoenix–Mesa nonattainment area (NAA) would have attained the 2015 ozone National Ambient Air Quality Standards (NAAQS) by August 3, 2024, but for emissions emanating from outside of the United States. Ramboll conducted the modeling for the MAG Section 179B(b) demonstration using a CAMx modeling platform with 36/12/4 km nested domains for the summer of 2023. Ramboll evaluation of the explicit ozone impacts of the Project using the MAG PGM platform are described in this report.

1.1 Air Quality Impact Analysis Requirements

The Project will be a major stationary source under the Prevention of Significant Deterioration (PSD) program for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM), PM_{10}, $PM_{2.5}$, and volatile organic compounds (VOC), and is therefore subject to PSD review requirements for these pollutants. One of the PSD requirements under 40 CFR §§ 51.166(k) or 52.21(k) is to perform an air quality impact analysis that demonstrates the Project will not cause or contribute to a violation of any National Ambient Air Quality Standard (NAAQS). The U.S. Environmental Protection Agency (EPA) has developed Significant Impact Levels (SILs) to define circumstances under which a source is not considered to contribute to a NAAQS violation, representing air quality impacts that are sufficiently small to be considered not meaningful (e.g., described by EPA as "trivial" or "de minimis").

EPA has published the Guideline on Air Quality Models (GAQM), codified at 40 CFR Part 51, Appendix W, which provides guidance for conducting PSD air quality impact analyses. EPA

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[1] EPA Guidance on the Development of MERPs.

[2] MAG 2025 CAA Section 179B(b) Retrospective Demonstration

states in the GAQM that "advances in chemical transport modeling science indicate that it is now reasonable to provide more specific, generally applicable guidance that identifies particular models or analytical techniques that may be used under specific circumstances for assessing the impacts of an individual source on secondary formation of ozone." When either a proposed project's NOx or VOC emissions exceed the applicable PSD Significant Emission Rates (SERs), an ozone NAAQS compliance demonstration is required. The Desert Sun Project's proposed NOx and VOC emissions are greater than the SERs, therefore an ozone impact analysis is required for the project.

1.2 Tier 1 and 2 Ozone Impact Analysis Methodologies

EPA has developed a two-tiered approach for conducting a single-source ozone impact analysis for PSD permitting. The Tier 1 ozone assessment relies on technically credible relationships between precursor emissions and ozone impacts derived from numerous PGM analyses of single sources and is implemented through the Modeled Emission Rate Precursors (MERPs) methodology as a screening-level compliance demonstration tool under the PSD program. If a Tier 1 MERPs analysis cannot demonstrate that the Project will either (1) result in ozone impacts below the applicable ozone Significant Impact Level (SIL) or (2) result in combined Project and representative background ozone concentrations below the ozone NAAQS, a more refined Tier 2 ozone impact analysis may be performed. A Tier 2 assessment involves the direct application of a PGM consistent with EPA's *Guidance on the Use of Models for Assessing the Impacts of Emissions from Single Sources on the Secondarily Formed Pollutants: Ozone and* $PM_{2.5}$ (EPA-454/R-16-005, December 2016), herein referred to as EPA's Single Source guidance. PGM models simulate chemical and physical processes within grid cells in a computational domain where Eulerian diffusion and transport represent the movement of chemical species between grid cells. One publicly available and well-documented PGM is the Comprehensive Air Quality Model with Extensions (CAMx)[3]. As described in the Single Source guidance, PGM models may be used to assess single-source contributions to ozone formation using several techniques, including the "brute-force" method. This method involves comparing model results from a base case including all existing emissions to a new source case that includes all existing plus the proposed source emissions. The difference between these absolute model results[4] provides an estimate of the ozone impacts attributable to the new source.

1.3 Interpretation of Tier 2 Model Results and Comparison to Ozone SIL

EPA's *Guidance for Ozone and Fine Particulate Matter Permit Modeling* (EPA-454/R-22-005, July 2022) describes the recommended processing of Tier 2 modeling results from the baseline and project scenarios for comparison of Project impacts to the ozone SIL. Section 5.3 of the guidance states:

First, estimate the maximum daily 8-hr ozone concentration (MDA8) at each receptor (grid cell) for each modeled day using the baseline scenario. Second, calculate the MDA8 at each

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[3] Comprehensive Air Quality Model with Extensions (CAMx)

[4] While CAMx model results are typically post-processed to estimate relative response factors at key monitors to adjust model results to better match actual measured concentrations, EPA states that for PSD permitting single source analyses the project source emissions are well characterized, therefore the use of the difference in absolute modeled impact is appropriate.

receptor for each modeled day for the project scenario (using the same 8-hr period used to estimate MDA8 in the baseline scenario). Third, estimate the difference in MDA8 between the project scenario and baseline scenario for each receptor and model simulation day. This difference is the impact from the project source.

Additional EPA guidance is provided in the 2022 *Guidance for Ozone and Fine Particulate Matter Permit Modeling* (herein referred to as the Ozone Modeling Guidance), where Section IV.4 states that (edited for clarity):

For a predicted violation of the ozone NAAQS at any grid cell, the predicted Project fourth-highest MDA8 ozone concentrations[5] *at the affected grid cell should be compared to the ozone SIL.*

While Section IV.4 of this EPA guidance focuses the SIL comparison on the 4th highest MDA8 ozone concentrations when an ozone NAAQS exceedance occurs, higher-ranked MDA8 concentrations at a grid cell may also remain above the ozone NAAQS; therefore, a more rigorous assessment would evaluate Project impacts at all MDA8 ranks at each grid cell starting with the 4th highest and continuing until the new source case MDA8 concentration is below the NAAQS. This is consistent with the approach used in the AERMOD model MAXDCONC option for source contribution analyses when there are modeled exceedances of the NAAQS.

1.4 Tier 1 Analysis of the Project's Ozone Impacts

The Project has completed a Tier 1 ozone impact assessment. Using the MERPs methodology, the Project's estimated ozone impact is 1.54 ppb (0.00154 ppm), which exceeds the ozone SIL of 1.0 ppb. Consequently, a cumulative Tier 1 ozone analysis was conducted using data from the nearest representative ozone background monitor, the Buckeye monitor operated by Maricopa County. The 2023-2025 ozone design concentration at the Buckeye monitor is 0.0677 ppm; when combined with the Project impact, the resulting total ozone concentration is 0.0692 ppm, which is below the ozone NAAQS of 0.07 ppm. The Buckeye monitor is located in the western portion of the Phoenix ozone NAA. The nearest ozone monitor within the NAA that violates the ozone NAAQS is the West Phoenix monitor, located approximately 100 km from the Project site. The NOx MERP value at a 100 km is 1,456 tons per year and based on the Project's NOx and volatile organic compound (VOC) emission rates, the estimated Project-related ozone impact at the nearest violating monitor is approximately 0.2 ppb. Therefore, the Tier 1 analysis demonstrates the Project will not cause or contribute to a violation of the ozone NAAQS in either the attainment area or the Phoenix ozone NAA.

1.5 Tier 2 Analysis Purpose and General Description

APS has elected to perform a more refined Tier 2 analysis of Project-related ozone impacts within the Phoenix ozone NAA for the purpose of demonstrating that Project impacts throughout the NAA are less than the 1 ppb ozone SIL. This Tier 2 analysis supplements the

[5] Based on EPA definitions above, the *Project fourth-highest MDA8 ozone concentration* at a grid cell is equal to the difference between the base case fourth-highest MDA8 at the grid cell and the new source case concentration for the same 8-hr period as in the base case.

Tier 1 assessment and provides additional evidence that the Project will not cause or contribute to a violation of the ozone NAAQS.

Development of a Tier 2 CAMx modeling platform, including grid configuration, regional emissions inventory, meteorological inputs, and other required data, is a resource-intensive process; therefore, the Project's Tier 2 analysis was constructed using the existing CAMx modeling platform developed by the Maricopa Association of Governments (MAG) to support the MAG's Section 179B(b) demonstration analysis that was recently approved by EPA. MAG has prepared extensive documentation[2] for this CAMx platform and conducted a detailed model performance evaluation demonstrating that the model meets performance objectives for State Implementation Plan (SIP) analyses. The Project's Tier 2 analysis uses the same base case as in the MAG 179b(b) demonstration[6], with a new source scenario that incorporates emissions from the Desert Sun Generating Station. Model simulations for the base and new source scenarios are compared to quantify differences in predicted ozone concentrations, paired in space and time, for all grid cells within the Phoenix ozone NAA boundary, including grid cells that are partially within the NAA.

[6] One additional source was included in the base case scenario on the recommendation of MAG, the Solana Generating Station which is located outside of the ozone NAA.

2.0 Methodology

This chapter describes how the MAG photochemical grid model (PGM) platform was adapted for this evaluation. The discussion provides a brief overview of the modeling platform, the approach used to incorporate the Project emission sources, and the modeling configuration applied consistently across the PGM simulations.

2.1 MAG Modeling Platform

CAMx simulations were configured following the setup of the MAG Ozone SIP modeling platform, which is summarized below. Additional details regarding the MAG modeling platform configuration are provided in Appendix B of the MAG 2025 Clean Air Act Section 179B(b) demonstration[7].

The MAG modeling platform consists of three nested grids, including a master domain covering southwestern North America at 36 km horizontal resolution, an intermediate Arizona domain at 12 km resolution, and a fine-resolution domain covering the Maricopa ozone nonattainment area (NAA) at 4 km resolution (Figure 2-1). Table 2-1 and Table 2-2 show the horizontal grid resolution parameters. The vertical resolution for all domains spans 23 layers extending from the surface to the tropopause.

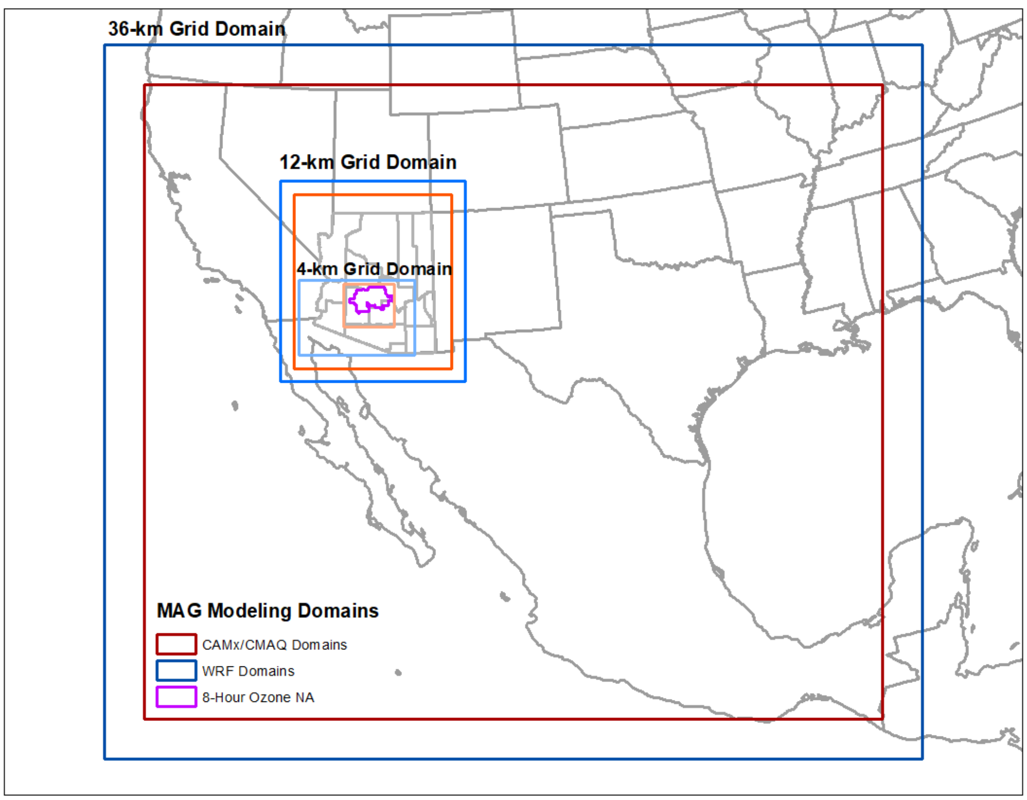

Figure 2-1. CAMx modeling domains for the MAG ozone modeling platform.

[7] MAG 2025 CAA 179B(b) Retrospective Demonstration-Appendices

Table 2-1. Projection parameters for the 36/12/4 km horizontal modeling domains.

Parameter	Value
Projection	Lambert-Conformal
1st True Latitude	33 degrees N
2nd True Latitude	45 degrees N
Central Longitude	112 degrees W
Central Latitude	33.5 degrees N

Table 2-2. Grid definitions for the 36/12/4 km modeling domains

Domain	Origin (SW) (km)	Extent (NE) (km)	NX	NY
36 km	(-1,026, -1,879.2)	(2,286, 964.8)	92	79
12 km	(-354, -1620)	(354, 472.8)	59	65
4 km	(-130, -324)	(94, 68.8)	56	47

The modeling period encompasses the summer ozone season from April 1 through September 30, 2023. Atmospheric chemical processes were represented using the Carbon Bond version 7 revision 1 (CB7r1) chemical mechanism. The modeling system includes three-dimensional meteorological fields generated using the Weather Research and Forecasting (WRF) model, as well as anthropogenic, biogenic, and fire emissions inventories developed with the Sparse Matrix Operator Kernel Emissions (SMOKE) processing system. Three-dimensional initial and boundary conditions for the master domain were derived from Ramboll's application of the GEOS-Chem global chemistry model for calendar year 2023. Emission inputs for the platform include:

- On-road Mobile Sources: Developed using the MOVES4 model with 2023 local travel activity data and vehicle age distributions.
- Non-road and Point Sources: Based on the 2023 emissions inventories provided by the Maricopa and Pinal County air quality departments to ensure high spatial accuracy in the 4 km domain.
- Aviation: Comprehensive emissions for 20 airports within the study area were generated using the Federal Aviation Administration's Aviation Environmental Design Tool (AEDT)version 3g.
- International Emissions: A high-resolution 2023 inventory was specifically developed for the northern Mexico border states (Sonora, Baja California, and Chihuahua) to accurately account for cross-border transport.
- Biogenic Sources: Natural emissions from vegetation and soils were estimated using the MEGAN version 3.2 model.
- Wildfire Activity: Day-specific wildfire emissions from the EPA 2023 National Emissions Inventory beta platform for domestic fires and the Fire INventory from NCAR (FINN) database for international fires

All emissions inventories were processed using SMOKE version 5.1 to produce the spatially, temporally, and chemically resolved inputs required for the CAMx simulations.

MAG evaluated the CAMx performance for 2023 ozone in the Maricopa NAA using statistical metrics including normalized mean bias (NMB), normalized mean error (NME), and the Index of Agreement, with performance targets of ±15% for NMB and <35% for NME. MAG found that CAMx generally met these targets, except for the one-hour ozone in June, which slightly exceeded the NMB goal. The Index of Agreement indicated good overall agreement between modeled and observed concentrations, although performance was worse at higher ozone levels (MDA8 > 60 ppb). The five controlling monitors (i.e., those with the highest 2023 ozone values) met the statistical goals and exhibited performance comparable to the overall monitoring network. Graphical analyses further supported these findings: time series comparisons showed that the models generally captured day-to-day MDA8 variability but tended to overpredict in June and underpredict in August; spatial evaluations indicated generally consistent performance across sites, with typical mean errors of 4 to 7 ppb and mean biases between −3 and 4 ppb, except at the Fountain Hills site where biases were higher (8 to 9 ppb). Scatter and "soccer goal" plots showed good alignment between modeled and observed ozone, with modest positive bias at higher concentrations, and distributional comparisons demonstrated that predicted ozone broadly matched observed patterns across percentiles, days of week, and diurnal cycles, while indicating month-to-month and time-of-day tendencies toward underprediction in April and August and overprediction during other months and most hours outside the afternoon. These results indicate that the model is suitable for SIP analysis and related applications. Project-related impacts are evaluated using the difference between absolute ozone concentrations between two CAMx scenarios. This brute force approach mitigates the influence of systematic model performance biases because the impacts represent the modeled ozone response to changes in the precursor emissions rather than absolute concentration levels.

2.2 Facility Emissions

Project-specific emissions information was provided by RTPEnv for use in the photochemical grid modeling analysis. The information supplied included the source type (natural gas-fired combined-cycle combustion turbine electric generating units), the number of emission units (two combustion turbines, designated U1 and U2), geographic coordinates indicating a location approximately 10 miles west of the Phoenix–Mesa ozone nonattainment area, and detailed stack parameters (including stack height, diameter, and flow rates). Emissions were specified as steady-state, continuous operation (24 hours per day, seven days per week), with no diurnal or seasonal variation.

The emissions modeled for the Project focused on the combustion turbine units, which account for approximately 99 percent of total Project NOx emissions. The turbines will be equipped with dry low-NOx combustors and selective catalytic reduction (SCR) for NOx control, as well as oxidation catalysts for CO and VOC control. To conservatively estimate maximum daily 8-hour ozone impacts, the modeled emissions include both full-load operational emissions and emissions associated with startup and shutdown activities. The Project permit application proposes up to 16 cold starts per year and 350 hot starts per turbine. For modeling purposes, a conservative worst-case daily operating scenario was assumed that maximized emissions. The scenario consists of one cold start (the highest emissions of any operating scenario), one shutdown, one additional hot start per turbine, combined with operation at 100 percent load with duct burner firing for the remaining hours of the day. Under this scenario, the resulting daily average emission rates for the primary ozone precursors are 91 lb/hr of NOx and 41 lb/hr of VOC for both turbines combined, and the NOx emissions were conservatively rounded up to 95 lb/hr. Table 2-3 summarizes the modeled emission rates and stack parameters for each turbine modeled.

Table 2-3. The Project's hourly emissions and stack parameters

Source ID	Stack Height (ft)	Temperature (°F)	Exit Velocity (fps)	Stack Diameter (ft)	PM_{10} (lb/hr)	$PM_{2.5}$ (lb/hr)	NO_2 (lb/hr)	SO_2 (lb/hr)	VOC (lb/hr)	CO (lb/hr)
U1	165	182.4	59.20	23	23.2	23.2	47.5	6.5	20.6	118
U2	165	182.4	59.20	23	23.2	23.2	47.5	6.5	20.6	118
Emission Totals					**46.4**	**46.4**	**95.0**	**13.0**	**41.2**	**236**

Ramboll compiled the Project emissions information into point-source inventory formats compatible with SMOKE and processed to generate model-ready, temporally allocated, and chemically speciated input files consistent with the EPA 2022v2 modeling platform and the CB7r1 chemical mechanism used in CAMx. Source Classification Code (SCC) 20100201 was assigned to both U1 and U2, representing natural gas-fired turbines used for electric generation, and this SCC assignment was used by SMOKE to apply the appropriate chemical speciation profiles for VOC and PM. A flat temporal profile was applied, consistent with the assumption of constant emissions across all hours and days. Standard SMOKE quality assurance procedures were performed, including verification of emission totals, stack parameter consistency, temporal allocation, and chemical speciation, to ensure that the processed emissions accurately reflect the Project inputs and are suitable for use in the CAMx simulations. Figure 2-1 illustrates the location of the Project emission sources relative to the Phoenix−Mesa ozone nonattainment area and the CAMx 4-km grid.

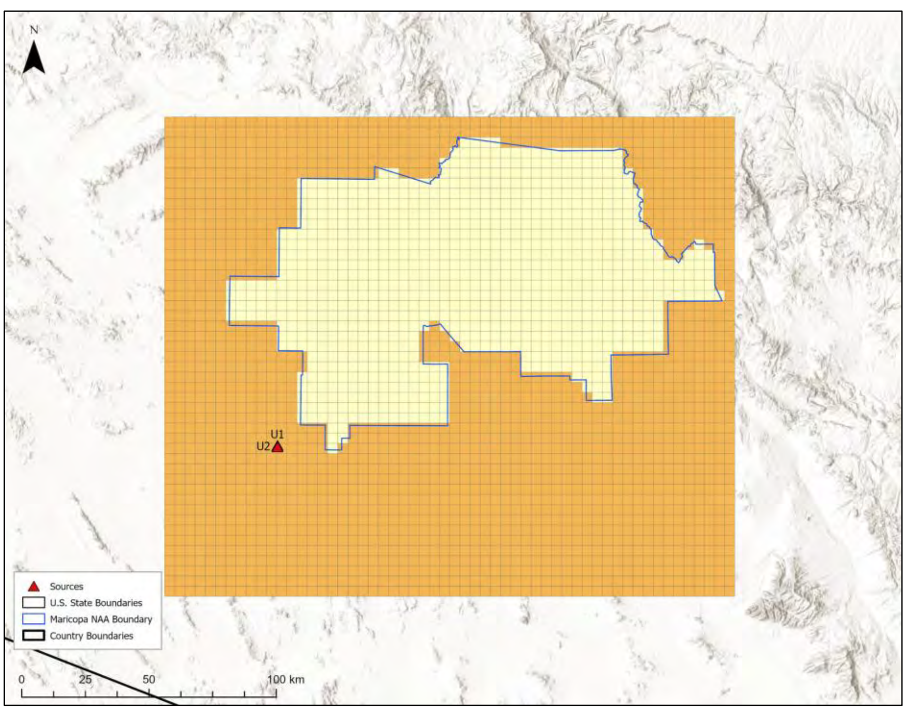

Figure 2-2. Project units' location (red triangles) relative to Phoenix-Mesa NAA (pale yellow) boundary on CAMx 4-km grid (orange).

2.3 CAMx Modeling

This section describes the CAMx modeling setup and configuration applied consistently to both the base case and the new source scenarios. Ramboll configured the 36/12/4-km CAMx scenarios using a modeling approach consistent with MAG 179B(b) demonstration. Simulations were conducted for the modeling period of April 1 through September 30, 2023, using meteorological fields, emissions inventories, initial and boundary conditions, and other ancillary input data provided by MAG. The CAMx scientific options and key configuration settings used in both simulations are summarized in Table 2-4.

As noted previously, the 2023 New Source Case CAMx simulation is configured identically to the 2023 Base Case, with the sole difference being the inclusion of additional emission sources representing the Project's worst-case emissions from Units U1 and U2. This approach ensures that any differences in simulated ozone concentrations between the two scenarios are attributable exclusively to the Project-related emissions.

Table 2-4. CAMx model options for simulations in the 2023 Tier 2 evaluation.

Science Options	CAMx	Comment
Model Codes	CAMx v7.32	Latest version of CAMx at time of study
Horizontal Grid Mesh	36/12/4 km	
36 km grid	92 x 79 cells	36/12/4 km two-way grid nesting
12 km grid	59 x 65 cells	With buffer
4 km grid	56 x 47 cells	With buffer
Vertical Grid Mesh	23 vertical layers defined by WRF	
Grid Interaction	36/12/4 km two-way nesting	
Initial Conditions (ICs)	GEOS-Chem, GEOS2CAMX v4.1	
Boundary Conditions (BCs)	GEOS-Chem, GEOS2CAMX v4.1	
Emissions	EPA's 2022 Emissions Modeling Platform, MAG 2023 emissions inventory, SMOKE v5.1	
Chemistry		
Gas Phase Chemistry	CB7r1	
Aerosol Thermodynamics	ISORROPIA	
Secondary Organic Aerosol	SOAP3	
Particle Size Distribution	Coarse/Fine	
Meteorological Processor	WRFCAMx v5.2, YSU Kv, KVPATCH v6	
Horizontal Diffusion	Explicit simultaneous 2-D solver	K-theory 1st order closure
Vertical Diffusion	Implicit backwards-Euler centered solver	Standard K-theory approach.
Deposition Schemes		
Dry Deposition	Zhang dry deposition scheme	
Wet Deposition	Exponential decay as a function of scavenging coefficient	
Numerics		
Gas Phase Chemistry Solver	Euler Backward Iterative (EBI)	EBI fast and accurate solver
Vertical Advection Scheme	Implicit backward-Euler hybrid centered/upstream solver	Eulerian continuity equation
Horizontal Advection Scheme	Piecewise Parabolic Method scheme	Eulerian continuity equation

3.0 Modeling Results

After completion of both 2023 CAMx simulations (Base Case and New Source Case scenarios), the hourly gridded ozone output fields were processed to derive Maximum Daily 8-hour Average (MDA8) ozone metrics for each day in the full April through September simulation period. Project-related ozone impacts within the Phoenix–Mesa ozone nonattainment area (NAA) were quantified using the brute force method, that is as the difference between the New Source Case and Base Case MDA8 results.

The resulting gridded MDA8 ozone concentrations were compiled into comma-separated value (CSV) summary files that captures the *n*th-highest MDA8 ozone concentration at each grid cell for both the New Source Case, the Base Case and the corresponding Project ozone impact (New Source minus Base) ensuring that the impacts are paired both in space and time. To support regulatory review, each grid cell was assigned a geographic indicator, developed using geographic information system (GIS) methods, identifying those cells located inside the Phoenix–Mesa NAA boundary (Figure 3-1).

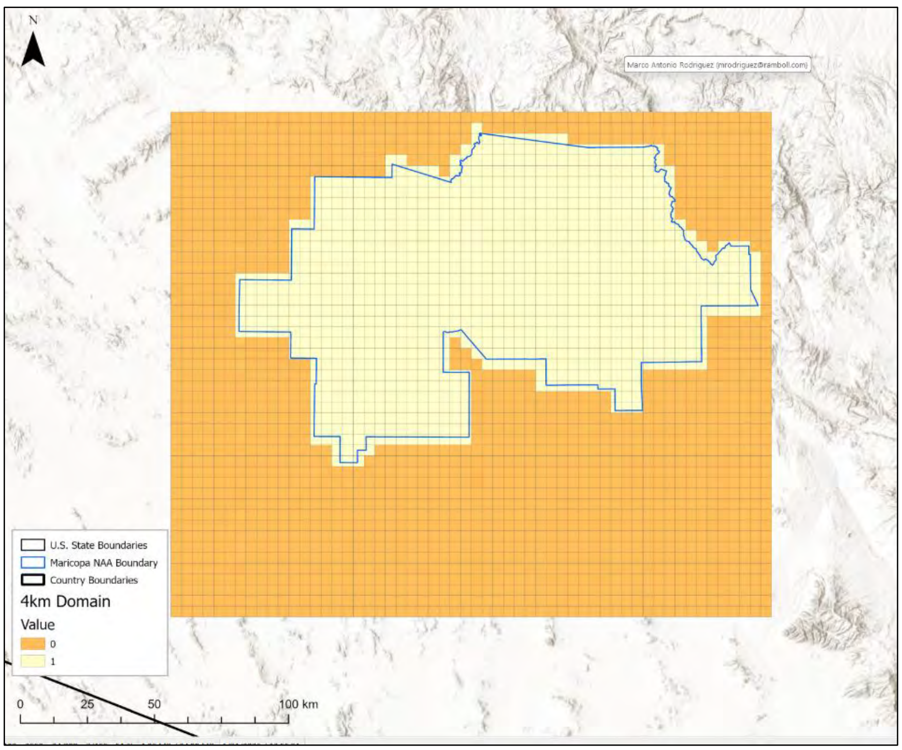

Figure 3-1. CAMx-4km grid cells that indicate whether they are located outside (0 flag) or within (1 flag) the NAA boundary.

The processed modeling results were evaluated to identify Project-related ozone impacts occurring within the NAA. A key regulatory metric is the impact on the 4th highest MDA8 ozone concentrations, as this determines the ozone design value and is the most directly comparable to the ozone NAAQS. Table 3-1 summarizes the ten highest Project-related ozone impacts within the NAA for the 4th highest MDA8 concentrations, derived using the brute force method as the difference between the New Source Case and Base Case simulations. For each ranked impact, the table reports the modeled date, 4 km grid cell location (column and row), Base Case and New Source Case MDA8 ozone concentrations, and the resulting Project impact. Although the table is limited to the ten highest impacts for clarity, the complete post-processed dataset includes results for all grid cells within the NAA but is not reproduced here.

Table 3-1. Ten highest Project-impacts to the 4th highest MDA8 ozone concentrations within the NAA.

Date	Col	Row	Base Case (ppb)	New Source Case (ppb)	Project Impacts* (ppb)
6/24/2023	14	18	75.00	75.39	0.40
6/24/2023	14	19	74.92	75.27	0.35
6/24/2023	13	19	75.06	75.40	0.34
6/24/2023	15	18	75.06	75.38	0.33
6/24/2023	15	17	75.44	75.76	0.33
6/3/2023	13	16	73.76	74.08	0.32
6/24/2023	14	20	75.04	75.36	0.32
6/24/2023	16	19	75.01	75.32	0.31
6/24/2023	15	19	75.02	75.32	0.31
6/3/2023	14	16	74.68	74.98	0.30

*Project impacts defined as difference in values Base − New Source

As shown in Table 3-1, both the Base Case and New Source Case 4th highest MDA8 ozone concentrations at these grid cells exceed the ozone NAAQS. It must be noted that these results are the absolute, unadjusted concentrations predicted by CAMx; they do not include the typical relative response factor (RRF) adjustments used for SIP modeling purposes. Even though the modeled concentrations exceed the ozone NAAQS, the incremental impacts attributable to the Project for the ten most affected cells within the NAA are all below the SIL. Since MDA8 ozone concentrations may exceed the NAAQS at rankings other than the 4th highest value, Project impacts associated with those exceedance instances within the NAA were also examined as part of this analysis. Summary tables like Table 3-1 were created for evaluating Project impacts for the first, second, and subsequent rankings through the tenth highest MDA8 concentrations within the NAA, and are included in Appendix A.

Table 3-2 summarizes the maximum Project-related ozone impacts within the Phoenix−Mesa NAA, ranked from the first through the tenth highest MDA8 concentrations for the New Source Case scenario. The table presents, for each ranked event, the date, grid cell location, Base Case and New Source Case MDA8 ozone concentrations, and the resulting Project impact calculated using the brute force difference method. As shown, all ranked Project impacts within the NAA are below the SIL, with the highest modeled Project impact of 0.85 ppb occurring for the fifth highest concentration of 73.7 ppb (highlighted in orange). These results indicate that, for the highest ozone concentration days and locations within the NAA, the modeled contribution from the Project are estimated to remain below the ozone SIL.

Table 3-2. Largest Overall Project-impacts to the 1st through the 10th highest MDA8 ozone concentrations within the NAA.

Ozone Ranking	Date	Col	Row	Base Case (ppb)	New Source Case (ppb)	Project Impacts* (ppb)
First	6/4/2023	13	16	79.08	79.73	0.66
Second	6/3/2023	16	16	76.38	76.65	0.27
Third	6/24/2023	13	16	75.60	76.10	0.50
Fourth	6/24/2023	14	18	75.00	75.39	0.40
Fifth	**7/1/2023**	**15**	**14**	**72.81**	**73.66**	**0.85**
Sixth	7/1/2023	15	15	72.75	73.54	0.79
Seventh	7/1/2023	16	14	72.35	73.08	0.73
Eighth	7/1/2023	17	14	72.50	73.13	0.63
Ninth	7/1/2023	18	17	72.15	72.54	0.39
Tenth	6/17/2023	17	16	70.80	71.19	0.39

*Project impacts defined as difference in values Base − New Source

4.0 Conclusions

This report documents a Tier 2 ozone impact analysis prepared to support Prevention of Significant Deterioration (PSD) permitting for the proposed Desert Sun Generating Station, a new NOx and VOC source to be located in Gila Bend, Arizona, near the western boundary of the Phoenix–Mesa 2015 8-hour ozone nonattainment area (NAA). Because the Project's precursor emissions exceed PSD significant emission rates, EPA guidance allows a two-tier approach to evaluate potential single-source ozone impacts: an initial Tier 1 screening using Modeled Emission Rates for Precursors (MERPs) and, if needed, a more refined Tier 2 photochemical grid model (PGM) assessment. Given the Project's proximity to the NAA and the desire to explicitly quantify impacts across the NAA, Ramboll applied the Maricopa Association of Governments' CAMx-based PGM platform (developed for MAG's CAA Section 179B(b) demonstration) to compare baseline and new-source scenarios and estimate Project-attributable changes in Maximum Daily 8-hour Average (MDA8) ozone concentrations.

Overall, the Tier 2 CAMx modeling indicates that the Desert Sun Project's incremental contribution to ozone within the Phoenix–Mesa NAA is below EPA's 1 ppb ozone Significant Impact Level (SIL) for key regulatory comparisons. Project impacts were quantified using the brute force difference between the New Source and Base Case simulations for the 4th-highest MDA8 concentrations (the relevant metric for ozone design values) as well as for other high-rank MDA8 days where modeled concentrations exceeded the ozone NAAQS. In all cases, the highest modeled Project-impacts within the NAA remain below the SIL, with an overall maximum impact of 0.85 ppb observed for the fifth highest MDA8 concentrations. The findings in this report support the conclusion that, at the proposed emissions levels and under the modeled worst-case operating assumptions, the Project is not expected to cause or contribute to an ozone NAAQS violation within the Phoenix–Mesa NAA.

APPENDIX A

Table A-1. Ten highest Project-impacts to the 1st highest MDA8 ozone concentrations within the NAA.

Date	Col	Row	Base Case (ppb)	New Source Case (ppb)	Project Impacts* (ppb)
6/4/2023	13	16	79.08	79.73	0.66
6/4/2023	14	16	79.45	80.01	0.56
6/4/2023	13	17	79.37	79.93	0.56
6/4/2023	13	18	79.61	80.08	0.47
6/4/2023	14	17	79.74	80.21	0.47
6/4/2023	15	16	80.27	80.72	0.45
6/4/2023	15	17	80.45	80.86	0.41
6/4/2023	15	15	80.72	81.14	0.41
6/4/2023	14	18	80.05	80.45	0.39
6/4/2023	15	18	80.27	80.66	0.39

*Project impacts defined as difference in values Base – New Source

Table A-2. Ten highest Project-impacts to the 2nd highest MDA8 ozone concentrations within the NAA.

Date	Col	Row	Base Case (ppb)	New Source Case (ppb)	Project Impacts* (ppb)
6/3/2023	16	16	76.38	76.65	0.27
6/3/2023	16	17	77.20	77.47	0.27
6/3/2023	16	18	76.56	76.82	0.26
6/3/2023	17	16	76.62	76.88	0.26
6/3/2023	16	19	76.51	76.75	0.25
6/3/2023	18	16	76.50	76.75	0.25
6/3/2023	17	17	77.63	77.87	0.24
6/3/2023	15	19	76.71	76.95	0.24
6/3/2023	18	17	77.66	77.90	0.24
6/3/2023	17	20	77.58	77.81	0.23

*Project impacts defined as difference in values Base – New Source

Table A-3. Ten highest Project-impacts to the 3rd highest MDA8 ozone concentrations within the NAA.

Date	Col	Row	Base Case (ppb)	New Source Case (ppb)	Project Impacts* (ppb)
6/24/2023	13	16	75.60	76.10	0.50
6/24/2023	13	17	75.47	75.93	0.46
6/24/2023	14	17	75.45	75.87	0.41
6/24/2023	14	16	75.68	76.07	0.39
6/24/2023	13	18	75.13	75.52	0.38
6/3/2023	15	16	75.67	75.96	0.29
6/3/2023	15	17	76.01	76.29	0.28
6/3/2023	15	18	75.76	76.02	0.25
6/3/2023	14	18	75.41	75.66	0.25
6/24/2023	15	15	75.63	75.85	0.22

*Project impacts defined as difference in values Base − New Source

Table A-4. Ten highest Project-impacts to the 4th highest MDA8 ozone concentrations within the NAA.

Date	Col	Row	Base Case (ppb)	New Source Case (ppb)	Project Impacts* (ppb)
6/24/2023	14	18	75.00	75.39	0.40
6/24/2023	14	19	74.92	75.27	0.35
6/24/2023	13	19	75.06	75.40	0.34
6/24/2023	15	18	75.06	75.38	0.33
6/24/2023	15	17	75.44	75.76	0.33
6/3/2023	13	16	73.76	74.08	0.32
6/24/2023	14	20	75.04	75.36	0.32
6/24/2023	16	19	75.01	75.32	0.31
6/24/2023	15	19	75.02	75.32	0.31
6/3/2023	14	16	74.68	74.98	0.30

*Project impacts defined as difference in values Base − New Source

Table A-5. Ten highest Project-impacts to the 5th highest MDA8 ozone concentrations within the NAA.

Date	Col	Row	Base Case (ppb)	New Source Case (ppb)	Project Impacts* (ppb)
7/1/2023	15	14	72.81	73.66	0.85
7/1/2023	16	15	73.16	73.90	0.73
6/24/2023	17	21	74.79	75.06	0.26
6/24/2023	19	23	74.43	74.69	0.26
6/24/2023	17	22	74.70	74.96	0.25
6/24/2023	19	22	74.42	74.67	0.25
6/24/2023	18	23	74.59	74.85	0.25
6/24/2023	18	21	74.59	74.84	0.25
6/24/2023	20	25	74.52	74.77	0.25
6/24/2023	18	22	74.52	74.77	0.25

*Project impacts defined as difference in values Base – New Source

Table A-6. Ten highest Project-impacts to the 6th highest MDA8 ozone concentrations within the NAA.

Date	Col	Row	Base Case (ppb)	New Source Case (ppb)	Project Impacts* (ppb)
7/1/2023	15	15	72.75	73.54	0.79
7/1/2023	17	15	73.48	74.21	0.72
7/1/2023	18	15	74.01	74.63	0.62
7/1/2023	18	16	73.43	74.02	0.59
7/1/2023	21	16	74.08	74.44	0.36
7/1/2023	22	16	73.78	74.11	0.33
6/3/2023	15	14	73.06	73.35	0.29
6/3/2023	16	14	73.22	73.50	0.28
7/1/2023	24	16	73.33	73.59	0.26
6/24/2023	19	24	74.46	74.72	0.25

*Project impacts defined as difference in values Base – New Source

Table A-7. Ten highest Project-impacts to the 7th highest MDA8 ozone concentrations within the NAA.

Date	Col	Row	Base Case (ppb)	New Source Case (ppb)	Project Impacts* (ppb)
7/1/2023	16	14	72.35	73.08	0.73
7/1/2023	17	16	72.94	73.57	0.63
7/1/2023	19	16	73.66	74.20	0.54
7/1/2023	16	16	72.67	73.17	0.50
7/1/2023	15	16	72.47	72.93	0.45
7/1/2023	20	16	73.80	74.22	0.43
7/1/2023	14	16	72.35	72.71	0.36
7/1/2023	20	17	73.21	73.56	0.35
7/1/2023	23	16	73.34	73.65	0.31
7/1/2023	25	16	73.22	73.45	0.23

*Project impacts defined as difference in values Base – New Source

Table A-8. Ten highest Project-impacts to the 8th highest MDA8 ozone concentrations within the NAA.

Date	Col	Row	Base Case (ppb)	New Source Case (ppb)	Project Impacts* (ppb)
7/1/2023	17	14	72.50	73.13	0.63
7/1/2023	19	17	72.48	72.89	0.40
7/1/2023	17	17	72.73	73.09	0.35
7/1/2023	23	17	71.77	72.02	0.25
7/1/2023	21	17	72.50	72.75	0.25
6/24/2023	23	26	74.58	74.81	0.23
6/24/2023	25	27	74.76	74.98	0.22
7/1/2023	20	18	72.86	73.08	0.22
6/24/2023	24	27	74.65	74.86	0.21
6/24/2023	24	25	74.15	74.35	0.21

*Project impacts defined as difference in values Base – New Source

Table A-9. Ten highest Project-impacts to the 9th highest MDA8 ozone concentrations within the NAA.

Date	Col	Row	Base Case (ppb)	New Source Case (ppb)	Project Impacts* (ppb)
7/1/2023	18	17	72.15	72.54	0.39
6/24/2023	24	26	74.05	74.27	0.23
6/24/2023	25	26	74.17	74.39	0.22
7/1/2023	19	18	72.24	72.45	0.22
7/1/2023	24	17	70.82	71.04	0.22
7/1/2023	21	18	72.26	72.46	0.20
6/24/2023	25	25	73.12	73.31	0.20
7/1/2023	18	18	72.67	72.86	0.19
6/9/2023	18	24	72.49	72.66	0.16
6/10/2023	13	20	70.34	70.48	0.15

Table A-10. Ten highest Project-impacts to the 10th highest MDA8 ozone concentrations within the NAA.

Date	Col	Row	Base Case (ppb)	New Source Case (ppb)	Project Impacts* (ppb)
6/17/2023	17	16	70.80	71.19	0.39
6/17/2023	18	16	71.19	71.54	0.34
6/30/2023	15	14	70.81	71.13	0.31
7/1/2023	22	17	71.69	71.96	0.27
6/30/2023	15	15	70.72	70.97	0.25
6/17/2023	25	17	70.16	70.40	0.24
6/17/2023	24	16	70.74	70.98	0.24
6/17/2023	27	17	70.26	70.48	0.22
6/17/2023	26	16	70.69	70.91	0.22
6/17/2023	27	16	70.58	70.80	0.21

*Project impacts defined as difference in values Base − New Source

Appendix C.

Control Technology Review for the Combined Cycle Combustion Turbine Electric Generating Units.

Desert Sun Power Plant

Construction and Title V Air Quality Operating Permit Application

Appendix C: Control Technology Review for the Combined Cycle Combustion Turbine Electric Generating Units.

May 2026

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Chapter 1. Executive Summary.

The Prevention of Significant Deterioration of Air Quality (PSD) program in the Code of Federal Regulations, 40 CFR §52.21 and County Rule 240, Section 305 requires that a new major stationary source within an attainment area must undergo PSD review and obtain a construction permit prior to commencing construction. The Desert Sun Power Plant will be subject to PSD review and will require the application of the Best Available Control Technology (BACT) for the control of carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM), PM_{10}, $PM_{2.5}$, volatile organic compounds (VOC), and greenhouse gas (GHG) emissions. This document is a control technology review or BACT analysis for the proposed combined cycle combustion turbine (CT) electric generating units.

Proposed BACT emission limits for the combined cycle CT electric generating units.

Pollutant	BACT Emission Limit	
	Normal Operation	Startup and Shutdown
Carbon Monoxide (CO)	2.0 ppmdv at 15% O_2 based on a 3-hour average	1. The total number of cold startup events may not exceed 16 events in any consecutive 12-month period. 2. The total number of warm and hot startups events combined may not exceed 350 events in any consecutive 12-month period. 3. The total CO emissions may not exceed 159.9 tons per year, based on a 12-month average.
Nitrogen Oxides (NO_x)	2.0 ppmdv at 15% O_2 based on a 3-hour average	1. The total number of cold startup events may not exceed 16 events in any consecutive 12-month period. 2. The total number of warm and hot startups events combined may not exceed 350 events in any consecutive 12-month period. 3. The total NO_x emissions may not exceed 161.2 tons per year, based on a 12-month average.
Particulate Matter (PM, PM_{10}, and $PM_{2.5}$)	15.0 lb/hour with duct firing 28.5 lb/hour without duct firing, based on a 3-hour average	

Proposed BACT emission limits for the combined cycle CT electric generating units.

Pollutant	BACT Emission Limit	
	Normal Operation	**Startup and Shutdown**
Volatile Organic Compounds (VOC)	5.0 pounds per hour without duct firing, based on a 3-hour average 12.1 pounds per hour with duct firing, based on a 3-hour average	1. The total number of cold startup events may not exceed 16 events in any consecutive 12-month period. 2. The total number of warm and hot startups events combined may not exceed 350 events in any consecutive 12-month period. 3. The total VOC emissions may not exceed 52.2 tons per year, based on a 12-month average.
Greenhouse Gas (GHG) Emissions	800 lb CO_2 per megawatt-hour of gross electric output based on a 12-month average (890 lb CO_2 per megawatt-hour of gross electric output based on a 12-month average if Subpart TTTTa is repealed)	
Startup Shutdown Events	"Hot startup" is defined as taking place within 8 hours after the previous shutdown. A hot startup is the period beginning with the ignition of fuel and ending 30 minutes later. "Warm startup" is defined as taking place more than 8 hours but less than 72 hours after the previous shutdown. A warm startup is the period beginning with the ignition of fuel and ending 60 minutes later. "Cold startup" is defined as taking place more than 72 hours after the previous shutdown. A cold startup is the period beginning with the ignition of fuel and ending 70 minutes later. "Shutdown" is defined as the period beginning with the initiation of gas turbine shutdown sequence and lasting until fuel combustion has ceased.	

Chapter 2. Purpose and Need.

The purpose of the Desert Sun Power Plant combined cycle electric generating units is to supply reliable, high-capacity electric service needed to serve the rapidly growing large customer load in Maricopa County, including data centers and other energy-intensive users. Demand from these customers has increased significantly in recent years and now exceeds the capacity that can be served by the existing electric generating infrastructure. These units are needed to provide firm, dispatchable electric power capable of operating during periods of grid stress and extreme weather conditions, ensuring system reliability and supporting continued economic development. These high-efficiency units will complement renewable electric power generation including solar and wind power by providing dependable capacity, fast response, and grid support needed to maintain stable service as the load of the APS system grows.

A critical component of this Project is that the proposed combined cycle units are very high efficiency, baseload units which can provide much-needed energy during any time of the day and for continuous periods, creating a strong complement to renewable energy resources such as solar. The proposed units will also provide dynamic voltage control for the electric grid. Dynamic voltage control is the ability of a generating resource to maintain voltage levels within acceptable limits. This Project will also provide system electric inertia (kinetic energy stored during the units' operation) and frequency response (the ability of a generating resource to aid balance between generation and load on the grid) necessary for electric system stability. Batteries and renewable energy systems such as wind and solar cannot provide this necessary grid support. These attributes of the proposed combined cycle units are critical when the electric supply resource portfolio includes more and more intermittent, renewable resources such as wind and solar.

Chapter 3. Control Technology Review Methodology.

3.1 Best Available Control Technology (BACT).

The Clean Air Act defines “best available control technology” (BACT) as:

> “…an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of ‘best available control technology’ result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act. Emissions from any source utilizing clean fuels, or any other means, to comply with this paragraph shall not be allowed to increase above levels that would have been required under this paragraph as it existed prior to November 15, 1990.”

Under the Maricopa County Air Pollution Control Regulations, Rule 100, Section 200.25, “best available control technology” (BACT) means:

200.25 BEST AVAILABLE CONTROL TECHNOLOGY (BACT): An emissions limitation, based on the maximum degree of reduction for each pollutant, subject to regulation under the Act, which would be emitted from any proposed stationary source or modification, which the Control Officer, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combination techniques for control of such pollutant. Under no circumstances shall BACT be determined to be less stringent than the emission control required by an applicable provision of these rules or of any State or Federal laws (“Federal laws” include the EPA approved State Implementation Plan (SIP)). If the Control Officer determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

The BACT requirement applies for a given pollutant to each individual new or modified emission unit when the project, on a facility-wide basis, has a significant net emissions increase for that pollutant. Individual BACT determinations are performed on a unit-by-unit, pollutant-by-pollutant basis.

3.2 Top Down BACT Methodology.

The United States Environmental Protection Agency (U.S. EPA) recommends a "top-down" approach in conducting a BACT or Lowest Available Emission Rate (LAER) analysis. This method evaluates progressively less stringent control technologies until a level of control considered BACT is reached, based on the environmental, energy, and economic impacts. The five steps of a top-down BACT analysis are:

1. Identify all available control technologies with practical potential for application to the emission unit and regulated pollutant under evaluation;
2. Eliminate all technically infeasible control technologies;
3. Rank remaining control technologies by effectiveness and tabulate a control hierarchy;
4. Evaluate most effective controls and document results; and
5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

The impact analysis of any BACT review includes an evaluation of environmental, energy, technical, and economic impacts. The net environmental impact associated with a control alternative may be considered if dispersion modeling analyses are performed. The energy impact analysis estimates the direct energy impacts of the control alternatives in units of energy consumption. If possible, the energy requirements for each control option are assessed in terms of total annual energy consumption. The economic impact of a control option is assessed in terms of cost effectiveness and ultimately, whether the option is economically reasonable. The economic impacts are reviewed on a cost per ton controlled basis, as directed by the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Cost Control Manual, Fifth Edition.

The EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which EPA believes must be met by any BACT determination, irrespective of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available technologies: i.e., those that provide the "maximum degree of emissions reduction." Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts" contained in the record of the permit decisions.

3.3 Technical Feasibility.

Step 2 of the BACT analysis involves the evaluation of all of the identified available control technologies from Step 1 to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar emission source, or there is technical agreement that the technology can be applied to the emission source. Technical infeasibility is demonstrated through clear physical, chemical, or other engineering principles that demonstrate that technical difficulties preclude the successful use of the control option.

The technology must be commercially available for it to be considered as a candidate for BACT. EPA's New Source Review Workshop Manual, page B.12 states, "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."

In general, if a control technology has been "demonstrated" successfully for the type of emission source under review, then it would normally be considered technically feasible. For an undemonstrated technology, "availability" and "applicability" determine technical feasibility. Page B.17 of the New Source Review Workshop Manual states:

> Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.
>
> Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:
>
> - concept stage;
> - research and patenting;
> - bench scale or laboratory testing;
> - pilot scale testing;
> - licensing and commercial demonstration; and
> - commercial sales.

Applicability involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission source), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission source may not be applicable to a similar source depending on differences in gas stream characteristics.

3.4 Economic Feasibility.

Economic feasibility is normally evaluated according to the average and incremental cost effectiveness of the control option. From the U.S. EPA's New Source Review Manual, page B.31, average cost effectiveness is the dollars per ton of pollutant reduced. The incremental cost effectiveness is the cost per ton reduced from the technology being evaluated as compared to the next lower technology. The EPA NSR Review Manual states that, "where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if any, between the application of the control technology on those sources and the particular source under review".

In addition to the average and incremental cost effectiveness analysis, EPA has also used direct comparisons of control technology costs to overall project costs as part of recent GHG BACT determinations. Regarding economic impacts, in its PSD GHG BACT guidance EPA states[1]:

[1] EPA, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases,* (Mar. 2011), page 42.

EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible.

The U.S. EPA evaluated the costs of CCS in its Response to Public Comments (October, 2011) for the Palmdale Hybrid Power Project, a 570 MW power plant based on approximately 520 MW of natural gas-fired combined cycle units and 50 MW of solar photovoltaic systems. In the EPA's analysis, the estimated capital costs for the Project are $615-$715 million, equal to an annualized cost of about $35 million over the 20-year lifetime of the facility. In comparison, the estimated annual cost for CCS for this Project is about $78 million, ***or more than twice the value of the facility's annual capital costs***. Based on these very high costs, EPA eliminated CCS as an economically infeasible control option. The EPA's decision to reject CCS based on these very high annual costs was upheld on appeal by the U.S. EPA's Environmental Appeals Board (EAB), PSD Appeal No. 11 -07, decided September 17, 2012.

The EAB also rejected a challenge to a PSD permit for the construction of a new ethylene production unit in Baytown, Texas. The EAB upheld the determination that the installation of CCS was too expensive, on a total cost basis, to be selected as BACT for limiting GHG emissions from the proposed unit.

3.4.1 Average Cost Effectiveness.

In the EPA's New Source Review Manual, page B.37, average cost effectiveness is calculated as:

$$\text{Average Cost Effectiveness (\$ per ton removed)} = \frac{\text{Control option annualized cost}}{\text{Baseline emission rate} - \text{Control option emissions rate}}$$

The average cost effectiveness is based on the overall reduction in the air pollutant from the baseline emission rate. In the draft Workshop Manual, the EPA states that the baseline emission rate represents uncontrolled emissions for the source. However, the manual also states that when calculating the cost effectiveness of adding controls to inherently lower emitting processes, baseline emissions may be assumed to be the emissions from the lower emitting process itself.

3.4.2 Incremental Cost Effectiveness.

In addition to determining the average cost effectiveness of a control option, the U.S. EPA's New Source Review Manual states that the incremental cost effectiveness between dominant control options should also be calculated. The incremental cost effectiveness compares the costs and emissions performance level of a control option to those of the next most stringent control option:

$$\text{Incremental Cost (\$ per incremental ton removed)} = \frac{\text{Control option annualized cost} - \text{Next control option annualized cost}}{\text{Next control option emission rate} - \text{Control option emissions rate}}$$

3.5 Alternative to Top-Down BACT Analysis

In the Maricopa County Air Quality Permitting Handbook, August 2023, MCAQD states that to streamline the BACT selection process, MCAQD will accept BACT for the same or similar source category as listed by the South Coast Air Quality Management District (SCAQMD), San Joaquin Valley Air Pollution Control District (SJVAPCD), the Bay Area Air Quality Management District (BAAQMD), or another regulatory agency accepted by MCAQD as a viable alternative.

If an owner or operator of a source opts to select control technology for the same or similar source category accepted by the air quality management districts in California, the owner or operator may forego conducting the top-down BACT analysis.

3.6 Scope of the Control Technology Review.

The U.S. EPA has a longstanding policy regarding the scope of control technology options which the review agency may consider in a control technology review or BACT analysis. The scope of potential options relates directly to a proposed project's basic purpose or design. In short, the list of options should not include processes or options that would fundamentally redefine the source proposed by the applicant.

In the U.S. EPA EAB decision on the Prairie State Generating Station, PSD Appeal No. 05-05, the EAB explained (pages 27-28) that the facility's "basic purpose" or basic design," as defined by the applicant, is the fundamental touchstone of EPA's policy on "redefining the source":

> …Congress intended the permit applicant to have the prerogative to define certain aspects of the proposed facility that may not be redesigned through application of BACT and that other aspects must remain open to redesign through the application of BACT. The parties' arguments, properly framed in light of their agreement on this central proposition, thus concern the proper demarcation between those aspects of a proposed facility that are subject to modification through the application of BACT and those that are not.
>
> We see no fundamental conflict in looking to a facility's basic "purpose" or to its "basic design" in determining the proper scope of BACT review, nor do we believe that either approach is at odds with past Board precedent.

This EAB decision was upheld by the United States Court of Appeals, 7th Circuit.[2]

When EPA issued guidance in 2011 for conducting control technology reviews for greenhouse gas (GHG) emissions, EPA confirmed that a BACT analysis should not redefine the source's purpose:[3]

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[2] *Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007).

[3] U.S. EPA, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases* 26 (Mar. 2011) (citing *Prairie State*, 13 E.A.D. at 23).

> While Step 1 [of a BACT process] is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include lower pollution processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.

The EAB has analyzed the redefinition of the source concept in the context of a past permitting proceeding similar to the proposed Project. In their challenges to a PSD permit issued for the Pio Pico Energy Center, petitioners asserted before the EAB that EPA had erred in eliminating combined-cycle gas turbines in Step 2 of its BACT analysis for GHG emissions. Like the proposed project, Pio Pico is a simple cycle gas-fired facility designed to back up renewable generation by providing peaking and load-shaping capability. As the EAB recognized in its Pio Pico decision and consistent with EPA guidance, a permitting authority can consider peaking facilities, intermediate load facilities and base load facilities to be different electricity generation source types. The EAB explained how "plants operating in 'peaking mode' typically remain idle much of the time but can be started up when power demand increases … and, unlike base load plants, typically use simple-cycle rather than combined-cycle units as well as smaller turbines."[4]

The U.S. EPA has also addressed the issue of whether a peaking facility must consider energy storage such as batteries in the control technology review. In the U.S. EPA's Environmental Appeals Board (EAB) decision for the APS Ocotillo Power Plant[5], the EAB stated that "Maricopa County did not abuse its discretion when it determined that pairing energy storage at this facility would "redefine the source", making the following statements and conclusions.

> But Step 1's broad look is "not without limits." *Id*. Consideration of fundamentally different facility types than those proposed by permit applicants generally is not required. Indeed, EPA guidance and Board precedent, affirmed by the U.S. Court of Appeals for the Seventh Circuit, give permitting authorities the discretion to exclude a proposed control alternative from consideration in the BACT analysis, if that proposed alternative would "redefine the design of the source."

The EAB went on to state (page 336):

> As explained in *La Paloma*, to determine whether an emissions control option would fundamentally redefine a proposed source, permit issuers should begin by examining how the permit applicant defines the proposed facility's "end, object, aim, or purpose," i.e., its "basic design." That "basic design" typically is set forth in the permit application and supporting materials in the administrative record. *Id*. at 286; *accord Palmdale*, 15 E.A.D. at 731; *Desert Rock*, 14 E.A.D. at 530; *Prairie State*, 13 E.A.D. at 21-23. The permit issuer should then take a "hard look" at the applicant's "basic design," identifying design elements that are "inherent" to the applicant's purpose and design elements that possibly could be altered to achieve pollutant emissions reductions without disrupting that purpose.

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[4] *In re Pio Pico Energy Center*, PSD Appeal Nos. 12-04 through 12-06, slip op. at 63 (EAB Aug. 2, 2013).

[5] In Arizona Public Services Company, PSD Appeal No. 16-01, Order Denying Review, September 1, 2016 page 328.

The EAB concluded this issue by stating:

> The administrative record in this case supports Maricopa County's conclusion that integrating energy storage into the Ocotillo project would interfere with Arizona Public Service's ability to meet its customers' needs for "rapid, reliable power," as that option likely would not allow Arizona Public Service to meet "short peak demand[s]," "several short peak demands in a row," or "extended peak demand[s]" on an "immediate basis." *See* RTC at 8-9. For example, Sierra Club concedes on appeal that the paired energy storage option it advocates would not allow Arizona Public Service to fire the turbines to maximum capacity in 2 minutes. Pet. at 16 & n.12. As such, the option would not fulfill Arizona Public Service's project purpose. Maricopa County reasonably determined that energy storage would not be adequate to stabilize the electrical grid, as necessary in a situation with a large and growing proportion of intermittent power sources such as solar and wind. *See* RTC at 11-12. The record supports a determination that these aspects of the facility's design are inherent ones, central to Arizona Public Service's business purpose in proposing the Ocotillo Modernization Project, and Maricopa County appropriately identified them as such. *Id*. at 8-9, 11-12.

In the U.S. EPA's Response to Comments on the Red Gate PSD Permit for GHG Emissions, PSD-TX-1322-GHG, February 2015,[6] issued for a peaking facility to be comprised of reciprocating internal combustion engines (RICE), EPA determined that "energy storage cannot be required in the Step 1 BACT analysis as a matter of law." *Id.* at 1 (explaining that "'incorporating energy storage' in Step 1 of the BACT analysis for a [RICE] resource would constitute the consideration of an alternative means of power production in violation of long-established principles for what can occur in Step 1 of the BACT analysis") (citing *Sierra Club v. EPA*, 499 F.3d 653, 655 (7th Cir. 2007)). EPA concluded that energy storage, either "to replace all or part of the proposed . . . project," would fundamentally redefine the source. *Id.* at 2.

Like this Project, the purpose of the Red Gate project was to provide reliable, rapidly dispatchable power to support renewables and the transmission grid. Because "energy storage first requires separate generation and the transfer of the energy to storage to be effective . . . [it] is a fundamentally different design than a RICE resource that does not depend upon any other generation source to put energy on the grid." *Id.* Energy storage could not meet that production purpose for the duration or scale needed. *Id.* at 2-3. As EPA correctly observed, "[t]he nature of energy storage and the requirement to replenish that storage with another resource goes against the fundamental purpose of the facility." *Id.* at 3.

Similarly, in another PSD permit for a peaking facility for the Shady Hills Generating Station (Jan 2014), this time with natural gas-fired simple cycle units, EPA also concluded that energy storage would not meet the purpose of the facility and therefore should not be considered in the BACT analysis. [7]

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[6] *Response to Public Comments* for the South Texas Electric Cooperative, Inc. – Red Gate Power Plant PSD Permit for Greenhouse Gas Emissions, PSD-TX-1322-GHG (Nov. 2014), http://www.epa.gov/region6/6pd/air/pd-r/ghg/stec-redgate-resp2sierra-club.pdfNov%2014 .

[7] Responses to Public Comments, Draft Greenhouse Gas PSD Air Permit for the Shady Hills Generating Station at 10-11 (Jan 2014), http://www.epa.gov/region04/air/permits/ghgpermits/shadyhills/ShadyHillsRTC%20_011314.pdf.

Chapter 4. Carbon Monoxide (CO) Control Technology Review.

Carbon monoxide (CO) is emitted from combustion turbines as a result of incomplete combustion. Therefore, the most direct approach for reducing CO emissions and also reduce the other related pollutants is to improve combustion. Incomplete combustion also leads to emissions of volatile organic compounds (VOC) and organic hazardous air pollutants (HAP) such as formaldehyde. CO emissions as well as VOC and organic HAP emissions may also be reduced using post combustion air quality control systems.

4.1 BACT Baseline.

Maricopa County SIP Rule 322 § 307 limits CO emissions to no more than 400 ppmvd corrected to 15% oxygen for stationary gas turbines. For these proposed CTs, this would be equal to 0.9 lb/mmBtu and 4,212 pounds per hour at the maximum rated heat input with duct firing.

4.2 STEP 1. Identify All Available Control Technologies.

Table C4-1 is a summary of CO emission limits for large natural gas-fired combined cycle CTs from the U.S. EPA's RACT/BACT/LAER, the South Coast Air Quality Management District's (SCAQMD) BACT guidelines, and from recently issued permits.

TABLE C4-1. CO BACT limits for natural gas-fired combined cycle CTs during normal operation.

Facility	State	Permit Date	CT Model or MW	Limit, ppmdv at 15% O_2	Averaging Period	Control Systems
Maple Creek Energy, LLC	IN	2023	GE 7HA.02 CC CTs	2.0	3-hour	DLN, OC
Entergy Orange County Power Station	TX	2023	Mitsubishi M501JAC	2.0	24-hour	DLN, OC
Mountain State Clean Energy LLC	WV	2022	GE 7HA.02 or GE 7HA.03	2.0	3-hour	DLN, OC
Nemadji Trail Energy Center	WI	2020	Siemens SGT6-8000 H	1.5	168-hour	DLN, OC
Virginia Electric and Power Company-Warren	VA	2019	Mitsubishi M501GAC	1.5 / 2.4*	1-hour	DLN, OC
Pasadena City Dept. of Water & Power	CA (SCAQMD)	2018	GE LM6000PG Sprint	2.0	1-hour	WI, OC
CPV Three Rivers, LLC	IL	2018	GE 7HA.02 CC CTs	2.0	3-hour	DLN, OC

Footnotes

DLN means dry low NO_x combustors; OC means oxidation catalyst system; WI means water injection.

* The limit of 1.5 ppmdv at 15% O_2 is without duct firing; the limit of 2.4 ppmdv is with duct firing.

Based on these recent decisions and a review of current CO control technologies, the available control options for CO (and VOC) emissions from natural gas-fired combined cycle CTs include the use of good combustion practices based on CT design and the use of oxidation catalysts as post combustion air quality control systems. Good combustion practices includes the use of dry low NO_x combustion or water injection.

4.2.1 Good Combustion Practices.

Good combustion practices, including the use of water injection or dry low NO_x combustors is an effective method for controlling CO (and VOC) emissions from these CTs. These combustion technologies are described below.

4.2.1.1 Water Injection.

Water injection is the most widely used combustion control technology for aero derivative CTs with capacities less than 100 MW. Aeroderivative CTs are adapted from aerospace jet engine technology and are characterized by a lightweight, modular design. Uncontrolled, conventional CT combustors are “diffusion controlled” where fuel and air are injected separately. Combustion occurs locally and in non-uniform mixing conditions which result in hot spots that can produce high levels of NO_x. The injection of water directly into the combustion section lowers the peak flame temperature and reduces thermal NO_x formation. Injection rates for both water or steam are usually described by a water-to-fuel ratio, referred to as omega (Ω), given on a weight basis (i.e., pounds of water per pound of fuel). By controlling combustion conditions, this process minimizes NO_x, CO and VOC emissions.

A significant advantage of water injection for simple cycle CTs is the ability to achieve higher peak power output levels with water injection. The use of water injection increases the mass flow through the CT which increases power output, especially at high ambient temperatures when peak power is often needed from the CTs, but is limited by the high ambient air temperature. However, water injection is not an available combustion technology for the proposed CTs which are much larger heavy duty CTs.

4.2.1.2 Dry Low NO_x Combustors.

As noted above, uncontrolled CT combustors are diffusion controlled where fuel and air are injected separately. Combustion occurs locally and in non-uniform mixing conditions which result in hot spots that can produce high levels of NO_x. For large, heavy duty CTs, dry low NO_x (DLN) combustors are an advanced combustion technology which premixes air and natural gas prior to injection into the CT. When the DLN combustors are operating in the full premixed mode, the uniform mixture of combustion air and fuel reduces hot spots and significantly reduces peak flame temperature. This combustion technology results in improved combustion efficiency, reduced CO and VOC emissions, and reduced NO_x formation.

Each CT will be equipped with state-of-the-art DLN combustion systems. GE Vernova’s DLN family (DLN 2/2.6/2.6+/2.6e) of combustion systems enables GE Vernova’s H-class gas turbines to reduce NO_x emissions while enabling high plant efficiency and extending outage intervals. The DLN 2.6e maintains many of the elements of GE Vernova’s DLN 2.6+ combustion system but introduces advanced premixing to the 7HA gas turbine combustor.

Like water injection, DLN combustors cannot achieve the full premix mode during periods of startup and shutdown. As a result, the CTs operate in diffusion combustion mode until sufficient air and fuel flow allow for full premix mode to occur. As a result, CO emissions can be elevated during startup and shutdown.

4.2.2 Oxidation Catalyst Systems.

The lowest CO (as well as VOC and organic HAP) emission levels have generally been achieved using oxidation catalysts installed as post combustion control systems. The typical oxidation catalyst is a rhodium or platinum (noble metal) catalyst on an alumina support material. This catalyst is typically installed in a reactor with flue gas inlet and outlet distribution plates. CO and VOC emissions react with oxygen (O_2) in the presence of the catalyst to form carbon dioxide (CO_2) and water (H_2O) according to the following general equations:

$2CO$	$+ O_2$	$\rightarrow$	$2CO_2$	(Carbon Monoxide Oxidation)
$2C_nH_{2n+2}$	$+ (3n + 1)O_2$	$\rightarrow$	$2nCO_2 + (2n+2)H_2O$	(VOC Oxidation)
CH_2O	$+ O_2$	$\rightarrow$	$CO_2 + H_2O$	(Formaldehyde Oxidation)

The generally acceptable catalyst operating temperatures range from 450 – 1,250 °F, with the optimum temperature range of 700 - 1,100 °F. Below approximately 450 ^oF, catalyst activity (and oxidation potential) is small. For this reason, the oxidation catalyst air quality control systems also are not operational during periods of startup and shutdown (SU/SD) because the exhaust gas temperatures are too low for these systems to function as designed. As a result, CO emissions may also be elevated during periods of startup and shutdown due to the inactivity of the oxidation catalyst systems.

4.3 STEP 2. Identify Technically Feasible Control Technologies.

Each of the available control options identified above including good combustion practices based on the CT combustor design and oxidation catalyst systems are technically feasible CO control technologies for the proposed combined cycle CT electric generating units.

4.4 STEP 3. Rank the Technically Feasible Control Technologies.

The highest level of control and lowest emission rate from the proposed combined cycle CTs is the use of good combustion practices in combination with oxidation catalysts. The lowest permitted emission limit is 1.5 ppmdv at 15% excess oxygen for the Nemadji Trail Energy Center (Wisconsin) and the Virginia Electric and Power Company Dominion Energy – Warren County Power Station (Virginia). Note that the new CTs for the Virginia Power CTs have a lower limit of 1.5 ppmdv with duct firing, and a higher limit of 2.4 ppmdv at 15% O_2 with duct firing. The Nemadji Trails permit includes a limit of 1.5 ppmdv, but is based on a much longer 168 hour (7 day) rolling average. The lower-ranked (less effective) control option is the use of good combustion practices based on CT design without oxidation catalysts.

4.5 STEP 4. Evaluate the Most Effective Controls.

The use of oxidation catalysts will cause a small back pressure increase to the CTs which will result in a small reduction in the CT efficiency. Oxidation catalysts will also increase the cost of electric power generated by reducing CT efficiency and increasing capital and O&M costs. However, these impacts are expected to be small. Therefore, it is appropriate that this strategy serve as the basis for establishing BACT for CO (and VOC) emissions.

As noted above, the air quality control systems including the dry low NO_x combustion systems and the oxidation catalyst systems are not operational during periods of startup and shutdown (SU/SD). During periods of startup and shutdown, the DLN combustors cannot achieve the full premix mode and the exhaust gas temperatures are too low for the oxidation catalyst systems to function as designed. As a result, CO emissions may be elevated during periods of startup and shutdown. For periods of startup and shutdown, APS proposes the use of good combustion practices designed to expeditiously startup and shutdown the CTs to minimize CO emissions.

4.5.1 Startup and Shutdown Emissions.

The CT air pollution control systems including the SCR and oxidation catalyst systems are not operational during periods of startup and shutdown (SU/SD) because the exhaust gas temperatures are too low for these systems to function as designed. In addition, the DLN combustors cannot operate in the full premix mode until sufficient flue flow is delivered to allow for full fuel and air premixing. As a result, CO, NO_x, and VOC emissions may be elevated during periods of startup and shutdown.

The time required to startup and shutdown a combined cycle CT is limited by the temperatures inside the heat recovery steam generator (HRSG) and the steam turbine. Severe and potentially hazardous plant conditions can occur if the HRSG or steam turbine are heated too rapidly. As a result, combined cycle CTs have three types of startup events, designated as cold, warm, and hot startup. These startup are defined as follows:

> ***Hot Startup*** is defined as taking place within 8 hours after the previous shutdown. The typical duration is 30 minutes.
>
> ***Warm Startup*** is defined as taking place more than 8 hours but less than 72 hours after the previous shutdown. The typical duration is 60 minutes.
>
> ***Cold Startup*** is defined as taking place more than 72 hours after the previous shutdown. The typical duration is 70 minutes.

Cold startup events are generally limited to occurring after a major unit outage such as a scheduled unit maintenance outage or a significant unit malfunction. Conversely, warm and hot startup events can occur much more frequently and can, in many cases, occur interchangeably. Shutdown events are essentially the same after any type of startup event with a typical duration of 12 minutes.

4.6 STEP 5. Proposed Carbon Monoxide (CO) BACT Determination.

4.6.1 Proposed BACT for Normal Operation.

Based on this analysis, APS has concluded that the use of good combustion practices including the use of dry low NO_x combustors in combination with the use of oxidation catalysts represents the best available control technology (BACT) for the control of CO emissions from the proposed GE Model 7HA.02 combined-cycle CTs. APS proposes the following limits as BACT for CO emissions from these CTs:

1. Carbon monoxide (CO) emissions may not exceed 2.0 parts per million on a dry volume basis (ppmdv), corrected to 15% O_2, based on a 3-hour average, when operated during periods other than startup/shutdown and tuning/testing.

APS proposes to demonstrate compliance with this emission limit by installing, operating, and maintaining a CO continuous emissions monitoring system (CEMS) installed and operated in accordance with the requirements of Performance Specification (PS) 4a for CO in 40 CFR 60, Appendix B and Appendix F.

4.6.2 Proposed BACT for Periods of Startup and Shutdown.

Please note that potential CO emissions for each unit, expressed in tons per year, are based on the following combustion turbine design specifications:

1. Total CO emissions during a cold startup event of 830 pounds.
2. Total CO emissions during a warm or hot startup event of 235 pounds.
3. Total CO emissions during a shutdown event of 185 pounds.
4. Total of 16 cold startup events in any consecutive 12-month period.
5. Total of 350 warm and hot startup events combined in any consecutive 12-month period.

Based on these design specifications, the potential startup and shutdown emissions for each unit are equal to 81.6 tons per year, and the total potential CO emissions for each unit, including normal operation, are equal to 159.9 tons per year. Therefore, limiting the total potential emissions for each unit to 159.9 tons per year will also ensure that the normal operation and SU/SD emissions are limited to represent BACT. Based on this analysis, APS proposes the following as BACT for the control of CO emissions from the proposed GE 7HA.02 combined cycle CTs during periods of startup and shutdown.

1. The total number of cold startup events may not exceed 16 events in any consecutive 12-month period.
2. The total number of warm and hot startups events combined may not exceed 350 events in any consecutive 12-month period.

3. The total CO emissions may not exceed 159.9 tons per year, based on a 12-month average.
4. “Hot startup” is defined as taking place within 8 hours after the previous shutdown. A hot startup is the period beginning with the ignition of fuel and ending 30 minutes later.
5. “Warm startup” is defined as taking place more than 8 hours but less than 72 hours after the previous shutdown. A warm startup is the period beginning with the ignition of fuel and ending 60 minutes later.
6. “Cold startup” is defined as taking place more than 72 hours after the previous shutdown. A cold startup is the period beginning with the ignition of fuel and ending 70 minutes later.
7. “Shutdown” is defined as the period beginning with the initiation of gas turbine shutdown sequence and lasting until fuel combustion has ceased.

Chapter 5. Nitrogen Oxides (NO_X) Control Technology Review.

Nitrogen oxides (NO_x) consist of both nitrogen oxide (NO), and nitrogen dioxide (NO_2). During combustion, NO usually accounts for about 90% of the total NO_x emissions. However, since NO is converted to NO_2 in the atmosphere, the mass emission rate of NO_x is usually reported as NO_2.

NO_x is formed during combustion by two major mechanisms; thermal formation (Thermal NO_x), and fuel formation (Fuel NO_x). Thermal NO_x results from the high temperature oxidation of nitrogen (N_2) and oxygen (O_2). In this mechanism, N_2 is supplied from air, which is 78% N_2 by volume. Thermal NO_x formation increases exponentially with temperature, becoming significant at temperatures above 2800 °F. Fuel NO_x results from the oxidation of organic nitrogen compounds in the fuel. Because fuel bound nitrogen is more easily converted to NO_x during combustion, nitrogen levels in fuel have a significant impact on NO_x formation. However, since natural gas has only trace organic nitrogen compounds, thermal NO_x is the primary source of NO_x emissions from natural gas-fired CTs.

5.1 BACT Baseline.

On January 9, 2026, the U.S. Environmental Protection Agency (U.S. EPA) finalized amendments to the *Standards of Performance for Stationary Combustion Turbines*, 40 CFR 60, Subpart KKKKa. These amendments set standards of performance for emissions of nitrogen oxide (NO_x) and sulfur dioxide (SO_2) from stationary CTs. The applicability requirements in 40 CFR § 60.4305a state:

> **§ 60.4305a Does this subpart apply to my stationary combustion turbine?**
>
> (a) Except as provided for in § 60.4310a, you are subject to this subpart if you own or operate a stationary combustion turbine that commenced construction, modification, or reconstruction after December 13, 2024, and that has a base load rating equal to or greater than 10.7 gigajoules per hour (GJ/h) (10 million British thermal units per hour (MMBtu/h)). Any additional heat input from duct burners used with heat recovery steam generating (HRSG) units or fuel preheaters is not included in the heat input value used to determine the applicability of this subpart to a given stationary combustion turbine. However, this subpart does apply to emissions from any associated HRSG and duct burner(s) that are associated with a combustion turbine subject to this subpart.
>
> (b) A stationary combustion turbine subject to this subpart is not subject to subpart GG or subpart KKKK of this part.

For large CTs with a base-load rated heat input greater than 850 mmBtu per hour and a utilization rate of more than 45%, the EPA set both an input based emission standard which are based on a 4-operating-hour rolling average basis and an optional output based emission standard which is based on a 30-operating-day average basis. In accordance with 40 CFR § 60.4350a(h), "Hours are not subcategorized by load for the purposes of determining the applicable output-based standard. The emissions standard for all hours, regardless of load, is the otherwise applicable full load emissions standard." For these combined cycle CTs, the output based performance standard is therefore 0.12 lb/MWh-gross for ALL hours of operation, and based on a 30-day average basis.

For compliance with the input based standards, 40 CFR § 60.4350a(g), states:

> (g) For each stationary combustion turbine demonstrating compliance on a heat input-based emissions standard, excess NOx emissions are determined on a 4-operating-hour averaging period basis using the NOx CEMS data and procedures specified in paragraphs (g)(1) and (2) of this section as applicable to the NOx emissions standard in table 1 to this subpart.
>
> (1) For each 4-operating-hour period, compute the 4-operating-hour rolling average NOx emissions as the heat input weighted average of the hourly average of NOx emissions for a given operating hour and the 3 operating hours preceding that operating hour using the applicable equation in paragraph (g)(2) of this section. Calculate a 4-operating-hour rolling average NOx emissions rate for any 4-operating-hour period when you have valid CEMS data for at least 3 of those hours (e.g., a valid 4-operating-hour rolling average NOx emissions rate cannot be calculated if 1 or more continuous monitors was out-of-control for the entire hour for more than 1 hour during the 4-operating-hour period).
>
> **(2) If you elect to comply with the applicable heat input-based emissions rate standard, calculate both the 4-operating-hour rolling average NOx emissions rate and the applicable 4-operating-hour rolling average NOx emissions standard, calculated using hourly values in table 1 to this subpart, using equation 4 to this section.**

Therefore, when demonstrating compliance with the heat input-based standard, you must calculate the heat input weighted actual emission rate AND the heat input weighted emission limit. In other words, both the actual emission rate and the emission limit are calculated for each hour of operation based on whether the CT was operating above or below 70% of the base load rating.

The applicable standards for these proposed GE 7HA.02 combined cycle CTs under 40 CFR § 60.4320 are summarized below.

1. 5 ppm at 15 percent O_2 (0.018 lb/mmBtu) based on a 4-hour rolling average, ***AND***

   96 ppm at 15 percent O_2 (0.35 lb/mmBtu) when operating at less than 70 percent of base load rating, or when operating at temperatures less than 0 °F.

   OR

2. 0.12 lb/MWh based on a 30-operating day rolling average.

Excerpts from Table 1 to Subpart KKKKa of Part 60 - Nitrogen Oxide Emission Standards for Stationary Combustion Turbines

Combustion Turbine Type	Combustion Turbine Base Load Rated Heat Input (HHV)	Input-Based NO_x Emission Standard[1]	Optional Output-Based NO_x Standard[2]
New, firing natural gas with utilization rate > 45 percent	**> 850 MMBtu/h**	**5 ppm at 15 percent O_2 or 7.9 ng/J (0.018 lb/MMBtu)**	**0.054 kg/MWh-gross (0.12 lb/MWh-gross) 0.055 kg/MWh-net (0.12 lb/MWh-net)**
New, firing natural gas with utilization rate ≤ 45 percent and with design efficiency ≥ 38 percent	> 850 MMBtu/h	25 ppm at 15 percent O_2 or 40 ng/J (0.092 lb/MMBtu)	0.38 kg/MWh-gross (0.83 lb/MWh-gross) 0.39 kg/MWh-net (0.85 lb/MWh-net)
New, firing natural gas with utilization rate ≤ 45 percent and with design efficiency < 38 percent	**> 850 MMBtu/h**	**9 ppm at 15 percent O_2 or 14 ng/J (0.033 lb/MMBtu)**	**0.17 kg/MWh-gross (0.37 lb/MWh-gross) 0.17 kg/MWh-net (0.38 lb/MWh-net)**
Located north of the Arctic Circle (latitude 66.5 degrees north), operating at ambient temperatures less than 0°F (-18°C), modified or reconstructed offshore turbines, operated during periods of turbine tuning, byproduct-fired turbines, and/or operating at less than 70 percent of the base load rating	**> 300 MMBtu/h**	**96 ppm at 15 percent O_2 or 150 ng/J (0.35 lb/MMBtu)**	**N/A**

[1] *Input-based standards are determined on a 4-operating-hour rolling average basis.*

[2] *Output-based standards are determined on a 30-operating-day average basis.*

5.2 BACT Control Technology Determinations.

Table C5-1 is a summary of NO_x emission limits for large natural gas-fired combined cycle CTs from the U.S. EPA's RACT/BACT/LAER database, the South Coast Air Quality Management District's (SCAQMD) BACT guidelines, and from recently issued permits. In accordance with the *Maricopa County Air Quality Permitting Handbook*, August 2023, MCAQD will accept BACT for the same or similar source category as listed by the South Coast Air Quality Management District (SCAQMD), San Joaquin Valley Air Pollution Control District (SJVAPCD), the Bay Area Air Quality Management District (BAAQMD), or another regulatory agency accepted by MCAQD as a viable alternative. We were only able to identify one BACT determination for NO_x emissions from the SCAQMD for combined cycle CTs larger than 40 MW. That determination was for the Pasadena City Department of Water & Power.

TABLE C5-1. NO_x BACT limits for combined-cycle, natural gas-fired combustion turbines during normal operation.

Facility	State	Permit Date	CT Model or MW	Limit, ppmdv at 15% O_2	Averaging Period	Control Systems
Maple Creek Energy, LLC	IN	2023	GE 7HA.02	2.0	3-hour	DLN, SCR
Entergy Orange County Power Station	TX	2023	Mitsubishi M501JAC	2.0	24-hour	DLN, SCR
Mountain State Clean Energy LLC	WV	2022	GE 7HA.02 or GE 7HA.03	2.0	3-hour	DLN, SCR
Nemadji Trail Energy Center	WI	2020	Siemens SGT6-8000 H	2.0	24-hour	DLN, SCR
Virginia Electric and Power Company	VA	2019	Mitsubishi M501GAC	2.0	1-hour	DLN, SCR
Pasadena City Dept. of Water & Power	CA (SCAQMD)	2018	GE LM6000PG Sprint	2.0	1-hour	WI, SCR
CPV Three Rivers, LLC	IL	2018	GE 7HA.02 CC CTs	2.0	3-hour	DLN, OC

Footnotes

DLN means dry low NOx combustors; WI means water injection; SCR means selective catalytic reduction.

5.3 STEP 1. Identify All Available Control Technologies.

Recent BACT determinations from the U.S. EPA's RACT/BACT/LAER Clearinghouse and the review of literature indicates five control technologies used to control NO_x emissions from combined cycle CTs:

1. Good Combustion Practices including:
    i. Water Injection (WI), or
    ii. Dry low NO_x (DLN) combustion,
2. Selective Catalytic Reduction (SCR), including hot SCR
3. EMx™ Catalytic Absorption process (EMx or SCONOx™)
4. Selective Non-Catalytic Reduction (SNCR).

5.3.1 Good Combustion Practices.

Good combustion practices, including the use of water injection or dry low NO_x combustors is an effective method for controlling CO (and VOC) emissions from these CTs. These combustion technologies are described below.

5.3.1.1 Water Injection.

Water injection is the most widely used combustion control technology for aero derivative CTs with capacities less than 100 MW. Aeroderivative CTs are adapted from aerospace jet engine technology and are characterized by a lightweight, modular design. Uncontrolled, conventional CT combustors are "diffusion controlled" where fuel and air are injected separately. Combustion occurs locally and in non-uniform mixing conditions which result in hot spots that can produce high levels of NO_x. The injection of water directly into the combustion section lowers the peak flame temperature and reduces thermal NO_x formation. Injection rates for both water or steam are usually described by a water-to-fuel ratio, referred to as omega (Ω), given on a weight basis (i.e., pounds of water per pound of fuel). By controlling combustion conditions, this process minimizes NO_x, CO and VOC emissions.

A significant advantage of water injection for simple cycle CTs is the ability to achieve higher peak power output levels with water injection. The use of water injection increases the mass flow through the CT which increases power output, especially at high ambient temperatures when peak power is often needed from the CTs, but is limited by the high ambient air temperature. However, water injection is not an available combustion technology for the proposed CTs which are much larger heavy duty CTs.

5.3.1.2 Dry Low NO_x Combustors.

As noted above, uncontrolled CT combustors are diffusion controlled where fuel and air are injected separately. Combustion occurs locally and in non-uniform mixing conditions which result in hot spots that can produce high levels of NO_x. For large, heavy duty CTs, dry low NO_x (DLN) combustors are an advanced combustion technology which premixes air and natural gas prior to injection into the CT. When the DLN combustors are operating in the full premixed mode, the uniform mixture of combustion air and fuel reduces hot spots and significantly reduces peak flame temperature. This combustion technology results in improved combustion efficiency, reduced CO and VOC emissions, and reduced NO_x formation.

Each CT will be equipped with state-of-the-art DLN combustion systems. GE Vernova's DLN family (DLN 2/2.6/2.6+/2.6e) of combustion systems enables GE Vernova's H-class gas turbines to reduce NO_x emissions while enabling high plant efficiency and extending outage intervals. The DLN 2.6e maintains many of the elements of GE Vernova's DLN 2.6+ combustion system but introduces advanced premixing to the 7HA gas turbine combustor.

Like water injection, DLN combustors cannot achieve the full premix mode during periods of startup and shutdown. As a result, the CTs operate in diffusion combustion mode until sufficient air and fuel flow allow for full premix mode to occur. As a result, CO emissions can be elevated during startup and shutdown.

5.3.2 Selective Catalytic Reduction (SCR).

Selective Catalytic Reduction (SCR) is a flue gas treatment technique for the reduction of NO_x emissions which uses an ammonia (NH_3) injection system and a catalytic reactor. An SCR system utilizes an injection grid which disperses NH_3 in the flue gas upstream of the catalyst. NH_3 reacts with NO_x in the presence of the catalyst to form nitrogen (gas) and water according to the following general equations:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$$

Catalysts are substances which evoke chemical reactions that would otherwise not take place, and act by providing a reaction mechanism that has a lower activation energy than the uncatalyzed mechanism. For SCR, the catalyst is usually a noble metal, a base metal (titanium or vanadium) oxide, or a zeolite-based material. Noble metal catalysts are not typically used in SCR because of their very high cost. To achieve optimum long-term NO_x reductions, SCR systems must be properly designed for each application. In addition to critical temperature considerations, the NH_3 injection must be carefully controlled to maintain an NH_3/NO_x molar ratio that effectively reduces NO_x. Excessive ammonia injection will result in NH_3 emissions, called ammonia slip.

SCR has the capability to make substantial reductions in NO_x emissions. For these CTs, the use of SCR is expected to reduce NO_x emissions by approximately 90%.

5.3.3 Selective Non-Catalytic Reduction (SNCR).

In a selective non-catalytic reduction (SNCR) control system, urea or ammonia is injected into boilers where the flue gas temperature is approximately 1,600 °F to 2,100 °F. At these temperatures, urea [$CO(NH_2)_2$] or ammonia [NH_3], reacts with NO_x, forming elemental nitrogen [N_2] and water without the need for a catalyst. The overall NO_x reduction reactions are similar to those for SCR. Multiple injection points are required to thoroughly mix the reagent into the boiler furnace. The limiting factor for an SNCR system is the ability to contact NO_x with the reagent without resulting in excessive ammonia slip, and without excessive ammonia decomposition before the NO_x emissions can be reduced.

SNCR has been widely used in circulating fluidized bed (CFB) boilers where the high alkaline ash loading of the CFB boilers makes 'high dust' loading SCR systems technically infeasible. However, the time and temperature range for SNCR is not compatible with CTs. We are not aware of the application of SNCR to any combustion turbine either in the U.S. or worldwide. Therefore, SNCR is not a technically feasible control technology for the proposed CTs.

5.3.4 EMx™ Catalytic Absorption/Oxidation (formerly SCONOx™).

EMx™ Catalytic Absorption/Oxidation (the second-generation of the SCONOx™ NOx Absorber technology) is based on a proprietary catalytic oxidation and absorption technology. EMx™ uses a potassium carbonate (K_2CO_3) coated catalyst to reduce CO to carbon dioxide (CO_2), and nitric oxide (NO) to nitrogen dioxide (NO_2). The NO_2 absorbs onto the catalyst to form potassium nitrite (KNO_2) and potassium nitrate (KNO_3). Dilute hydrogen gas is periodically passed across the surface of the catalyst to regenerate the K_2CO_3 catalyst coating. The regeneration cycle converts KNO_2 and KNO_3 to K_2CO_3, water (H_2O), and elemental nitrogen (N_2). This makes the K_2CO_3 available for further absorption and the water and nitrogen are exhausted.

ABB Alstom Power purchased a proprietary technology called SCONOx™ from Goal Line Environmental Technologies. A SCONOx™ system has been in operation since December of 1996 on the 30 MW Sun Law Energy Federal cogeneration plant in Vernon, California. Since August of 1999, SCONOx has been in operation on a 5 MW cogeneration plant at Genetics Institute in Andover, Massachusetts. The Redding Electric Utility in Redding, California installed a SCONOx™ system on a 43 MW combined cycle plant in 2002. ABB Alstom Power subsequently completed design of a scaled-up SCONOx™ system for 100 MW and greater combined cycle gas turbines.

A significant advantage of SCONOx™ is that it does not require ammonia or urea as a reagent. Limited data is available on the EMx™ Catalytic Absorption process, but the available data indicate that this technology cannot reliably reduce NO_x emissions below 3.0 ppmdv at 15% O_2. Furthermore, SCONOx™ is designed for temperatures of 300 °F to 700 °F. The EMx catalyst is also subject to reduced performance and deactivation due to exposure to sulfur oxides. Commercial experience with EMx is limited, with a majority of the units operating on units of 15 MW or less, and it appears at least one installation of EMx has reported trouble meeting permit limits (Grays Harbor BACT Analysis, WA).

Based on the above, we have concluded that EMx™ Catalytic Absorption/Oxidation (SCONOx™) is not a technically feasible control option for these proposed CTs.

5.4 STEP 2. Identify Technically Feasible Control Technologies.

Based on the discussion in Step 1, good combustion practices using dry low NO_x combustion and Selective Catalytic Reduction (SCR) are technically feasible control options. Selective non-catalytic reduction (SNCR) and EMx™ Catalytic Absorption/Oxidation are not a technically feasible control options for these proposed combined cycle CTs.

TABLE C5-2. Technical feasibility of the available NO_x control technologies.

Control Technology	Technical Feasibility	Basis
1. Good Combustion Practices using Water Injection (WI).	Infeasible	Water injection is not available for these large, heavy duty CTs.
2. Good Combustion Practices using Dry low NO_x (DLN) combustion.	Feasible	Proposed technology.
3. Selective Catalytic Reduction (SCR).	Feasible	Proposed technology.
4. EMx™ Catalytic Absorption process (EMx or SCONOx™).	Infeasible	Not demonstrated are large, heavy duty CTs.
5. Selective non-catalytic reduction (SNCR).	Infeasible	Time and temperature range required for SNCR is not compatible with CTs.

5.5 STEP 3. Rank the Technically Feasible Technologies.

DLN combustion combined with SCR is expected to achieve a NO_x emission rate of 2.0 ppmdv at 15% O_2 during normal operation.

5.6 STEP 4. Evaluate the Most Effective Controls.

APS proposes to utilize DLN combustion in combination with SCR which is the lowest emission rate technology. Therefore, further evaluation is unnecessary.

5.6.1 Startup and Shutdown Emissions.

The CT air pollution control systems including the SCR and oxidation catalyst systems are not operational during periods of startup and shutdown (SU/SD) because the exhaust gas temperatures are too low for these systems to function as designed. In addition, the DLN combustors cannot operate in the full premix mode until sufficient flue flow is delivered to allow for full fuel and air premixing. As a result, CO, NO_x, and VOC emissions may be elevated during periods of startup and shutdown.

The time required to startup and shutdown a combined cycle CT is limited by the temperatures inside the heat recovery steam generator (HRSG) and the steam turbine. Severe and potentially hazardous conditions can occur if the HRSG or steam turbine are heated too rapidly. As a result, combined cycle CTs have three types of startup events, designated as cold, warm, and hot startup. These startup are defined as follows:

> ***Hot Startup*** is defined as taking place within 8 hours after the previous shutdown. The typical duration is 30 minutes.
>
> ***Warm Startup*** is defined as taking place more than 8 hours but less than 72 hours after the previous shutdown. The typical duration is 60 minutes.
>
> ***Cold Startup*** is defined as taking place more than 72 hours after the previous shutdown. The typical duration is 70 minutes.

Cold startup events are generally limited to occurring after a major unit outage such as a scheduled unit maintenance outage or a significant unit malfunction. Conversely, warm and hot startup events can occur much more frequently and can, in many cases, occur interchangeably. Shutdown events are essentially the same after any type of startup event with a typical duration of 12 minutes.

5.7 STEP 5. Proposed Nitrogen Oxides (NO_x) BACT Determination.

5.7.1 Proposed BACT for Normal Operation.

Based on this analysis, APS has concluded that the use of good combustion practices including the use of dry low NO_x combustors in combination with the use of Selective Catalytic Reduction (SCR) represents the best available control technology (BACT) for the control of NO_x emissions from the proposed GE Model 7HA.02 combined-cycle CTs. APS proposes the following limits as BACT for NO_x emissions from these CTs during normal operation:

1. Nitrogen oxides (NO_x) emissions may not exceed 2.0 parts per million on a dry volume basis (ppmdv), corrected to 15% O_2, based on a 3-hour average, when operated during periods other than startup/shutdown and tuning/testing.

APS proposes to install and certify NO_x continuous emission monitoring systems (NO_x CEMS) consisting of a NO_x monitor and a diluent gas oxygen (O_2) monitor to determine the hourly NO_x emission rate in ppm corrected to 15% O_2 in accordance with the requirements of the Acid Rain Program in 40 CFR Part 75 to measure and report NOx emissions from these CTs.

5.7.2 Proposed BACT for Periods of Startup and Shutdown.

Please note that potential NO_x emissions for each unit, expressed in tons per year, are based on the following combustion turbine design specifications:

1. Total NO_x emissions during a cold startup event of 200 pounds.
2. Total NO_x emissions during a warm or hot startup event of 160 pounds.
3. Total NO_x emissions during a shutdown event of 16 pounds.
4. Total of 16 cold startup events in any consecutive 12-month period.
5. Total of 350 warm and hot startup events combined in any consecutive 12-month period.

Based on these design specifications, the potential startup and shutdown emissions for each unit are equal to 32.5 tons per year, and the total potential NO_x emissions for each unit, including normal operation, are equal to 161.2 tons per year. Therefore, limiting the total potential emissions for each unit to 161.2 tons per year will also ensure that the normal operation and SU/SD emissions are limited to represent BACT. Based on this analysis, APS proposes the following as BACT for the control of NO_x emissions from the proposed GE 7HA.02 combined cycle CTs during periods of startup and shutdown.

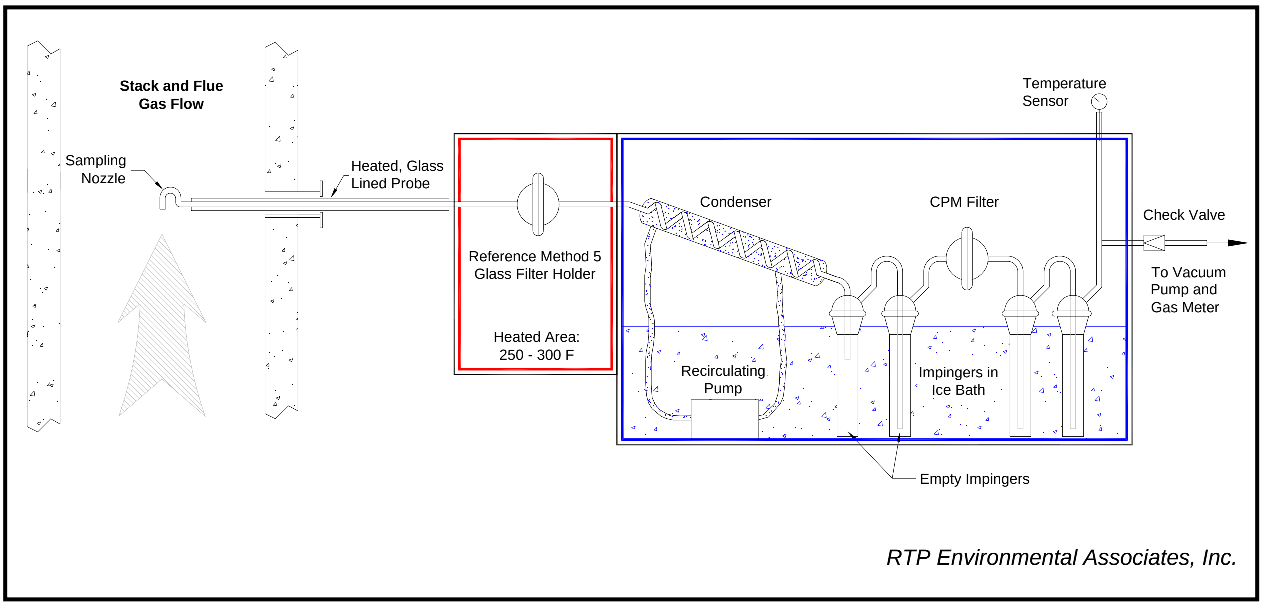
1. The total number of cold startup events may not exceed 16 events in any consecutive 12-month period.
2. The total number of warm and hot startups events combined may not exceed 350 events in any consecutive 12-month period.
3. The total NO_x emissions may not exceed 161.2 tons per year, based on a 12-month average.
4. “Hot startup” is defined as taking place within 8 hours after the previous shutdown. A hot startup is the period beginning with the ignition of fuel and ending 30 minutes later.
5. “Warm startup” is defined as taking place more than 8 hours but less than 72 hours after the previous shutdown. A warm startup is the period beginning with the ignition of fuel and ending 60 minutes later.
6. “Cold startup” is defined as taking place more than 72 hours after the previous shutdown. A cold startup is the period beginning with the ignition of fuel and ending 70 minutes later.
7. “Shutdown” is defined as the period beginning with the initiation of gas turbine shutdown sequence and lasting until fuel combustion has ceased.

Chapter 6. Particulate Matter, PM_{10}, and $PM_{2.5}$ Control Technology Review.

Emissions of particulate matter (PM), PM with particle sizes less than 10 microns (PM_{10}), and PM with particle sizes less than 2.5 microns ($PM_{2.5}$) from CTs result from PM in the combustion air, from ash in the fuel and, for water injected units, injected water, as well as from products of incomplete combustion. Since natural gas has virtually no inorganic ash, fuel ash is not a significant source of PM emissions. As a result, the primary sources of PM emissions from these CTs are expected to result from products of incomplete combustion, turbine wear, and particulate matter in the ambient air.

PM which exists as a solid or liquid at temperatures of approximately 250 ^{o}F are measured using U.S. EPA's Reference Method 5 or 17 and are commonly referred to as "front half" emissions. PM which exists as a solid or liquid at the lower temperature of 32 ^{o}F are measured using U.S. EPA's Reference Method 202, and is commonly referred to as "back half" or "condensable" PM. Condensable PM may include acid gases such as sulfuric acid mist, volatile organic compounds (VOC) and other materials, but does not include condensed water vapor. For this analysis, all PM emissions from these CTs are also assumed to be PM_{10} and $PM_{2.5}$ emissions.

FIGURE 8-1. Reference Method 5 and Reference Method 202 sample train.



6.1 BACT Baseline.

There are currently no emission standards for combustion or gas turbines under the New Source Performance Standards.

6.2 BACT Control Technology Determinations.

Table C6-1 is a summary of PM emission limits for natural gas-fired combined cycle CTs from the U.S. EPA's RACT/BACT/LAER database, the South Coast Air Quality Management District's (SCAQMD) BACT guidelines, and other permit determinations. Note that a number of the BACT emission limits are stated as a mass emission rate, expressed in pounds of PM per hour. In Table C6-1, these emission limits are also expressed in pounds per million Btu (lb/mmBtu). The emission limits for combined cycle CTs range from 0.0032 lb/mmBtu to 0.0078 lb/mmBtu. Several permits also establish higher PM emission limits – expressed both in lb/mmBtu and lb/hour - for duct firing as contrasted without duct firing. Please note that the BACT limits for the Virginia Electric and Power Company Warren County Power Station is for a smaller Mitsubishi Model M501 CT rated at 299,600 kW and 2,996 million Btu per hour heat input, and with a smaller duct burner rated at 500 mmBtu per hour.

TABLE C6-1. Recent PM BACT limits for combined-cycle, natural gas-fired gas turbines.

Facility	State	Permit Date	Throughput	Permit Limit, as Stated	Equivalent as lb/mmBtu
Maple Creek Energy, LLC	IN	2023	4,200 mmBtu/hr GEV 7HA.03	0.0074 lb/mmBtu	0.0074
Entergy Orange County Power Station	TX	2023	1,215 MW 3,756 mmBtu/hr	0.005 lb/mmBtu	0.005
Mountain State Clean Energy LLC	WV	2022	1,780 mmBtu/hr	0.0058 lb/mmBtu	0.0058
Lincoln Land Energy Center	IL	2022	3,647 mmBtu/hr	0.0032 lb/mmBtu	0.0032
Nemadji Trail Energy Center	WI	2020	229 MW 4,671 mmBtu/hr	36.3 lb/hour	0.0078
Virginia Electric and Power Company	VA	2019	2,748 mmBtu/hr 2,201 mmBtu/hr	14.0 lb/hour* 8.0 lb/hour*	0.0040* 0.0027*
CPV Three Rivers, LLC	IL	2018	GE 7HA.02 CC CTs	0.0069 lb/mmBtu	0.0069

Footnotes

*The limits of 14.0 lb/hour and 0.0040 lb/mmBtu are with duct firing; the limits of 8.0 lb/hour and 0.0027 lb/mmBtu are without duct firing.

6.3 STEP 1. Identify All Available Control Technologies.

The following PM, PM_{10}, and $PM_{2.5}$ control technologies were identified for natural gas-fired CTs:

1. Good Combustion Practices including:
   i. Water Injection (WI), or
   ii. Dry low NO_x (DLN) combustion,
2. Low Ash / Low Sulfur Fuel (i.e., natural gas and/or distillate fuel oil).
3. Post combustion control systems including fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, cyclones, and multiclones.

The proposed GE 7HA.02 CTs will be equipped with inlet air filters which remove dust and particulate matter from the inlet air. Note that these proposed heavy duty, industrial frame CTs will also be equipped with DLN combustors to enhance combustion efficiency, reduce flame temperatures, and reduce thermal NO_x formation. While water injection is an available control technology for smaller aeroderivative CTs, water injection is not an available control technology for these heavy duty CTs. The use of DLN combustion rather than water injection can actually help reduce PM emissions because while water injection uses very pure demineralized water, this water never-the-less does contain dissolved solids which can contribute to PM emissions.

CTs are internal combustion engines. Numerous other PM control systems are available for solid fuel-fired *external* combustion sources such as boilers and process heaters, including fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, and mechanical systems such as cyclones and multiclones. While these PM control systems are available technologies for solid fuel-fired *external* combustion sources such as boilers and process heaters, we are not aware of any examples where any of these post combustion PM control systems have been applied to natural gas-fired CTs. This is because natural gas-fired CTs already have very low PM emission rates similar to or even less than the *controlled* emission rates from solid fuel-fired boilers after the use of even the most advanced post combustion air quality control systems. In addition, the high exhaust gas flowrates and high exhaust gas temperatures from combined cycle CTs are not compatible with these PM control technologies intended for solid fuel-fired boilers and process heaters.

Because there is no evidence that the use of post combustion PM control systems such as fabric filter baghouses could actually reduce the already very low PM emission rates from CTs, fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, and mechanical systems such as cyclones and multiclones are not technically feasible control technologies for the control of PM emissions from the proposed CTs.

6.4 STEP 2. Identify Technically Feasible Control Technologies.

Based on the discussion in Step 1, Good Combustion Practices using Dry low NO_x combustion and the use of low ash and low sulfur fuels, i.e. natural gas, are technically feasible PM control options. Post combustion PM control systems including fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, and mechanical systems such as cyclones and multiclones are not technically feasible control technologies for the control of PM emissions from the proposed CTs.

6.5 STEP 3. Rank the Technically Feasible Technologies.

Based on the above analysis, the use of natural gas in combination with DLN combustion are technically feasible control options for these CTs. From Table C6-1, the use of these controls is expected to achieve PM, PM_{10}, and $PM_{2.5}$ emission rates in the range of 0.0032 to 0.0078 lb/mmBtu.

6.6 STEP 4. Evaluate the Most Effective Controls.

APS proposes utilizing the use of low ash and low sulfur fuel (natural gas) in combination with DLN combustion as the best available control technology (BACT). Because this is the highest level of control available for these CTs, further evaluation is unnecessary.

6.7 STEP 5. Proposed PM, PM_{10}, and $PM_{2.5}$ BACT Determination.

APS has concluded that the use of low ash and low sulfur fuel (natural gas) in combination with DLN combustion represents the best available control technology (BACT) for the control of particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions from the proposed GE 7HA.02 combined-cycle CTs. From the U.S. EPA's RACT/BACT/LAER database and other recently issued permits for large, combined cycle CTs, the emission limits for similar natural gas-fired CTs range from 0.0032 lb/mmBtu to 0.0078 lb/mmBtu. Based on the full load heat input rate for the proposed CTs of 4,680 mmBtu/hr with duct firing, these reported emission limits range from 15 to 37 lb/hr, and 12 to 29 lb/hour without duct firing.

The U.S. EPA Region 9 originally established the PM_{10} and $PM_{2.5}$ Pio Pico Energy Center (PPEC) BACT limit at 0.0065 lb/mmBtu. In response to an Environmental Appeals Board decision, EPA revised their BACT analysis by reviewing the lowest permitted emission limits and recent stack test data for similar sized natural gas-fired CTs. Region 9 considered a number of technical factors with the potential to impact the reliability and usefulness of the stack test data in projecting achievable emissions. EPA noted that there was significant variability in the test data from the three facilities analyzed. In addition, data for two of the three facilities reviewed was from the initial compliance tests on new units, while for the third facility the emission units were only four years old. EPA noted in its analysis that CTs are expected to last more than 20 to 30 years. It is unclear how much PM emissions may vary as the equipment ages and therefore it would be inappropriate to rely only on this emissions data to set a limit that is achievable on an ongoing basis over the life of the equipment. Setting a BACT limit based on limited testing of new units may not address long-term achievable emissions.

EPA’s review focused on three facilities that were all located in the same region and stated that because fuel sulfur content is one of the main contributors to PM emissions from gas turbines, and because the sulfur content in natural gas varies by region, it was appropriate to use data from the same region in California as the PPEC for setting the PM emission limit. Sulfur in the natural gas will be oxidized to form sulfur dioxide (SO_2), and it may also be oxidized to form sulfur trioxide (SO_3). When the exhaust gas temperature reaches the acid dew point (which will only occur in the atmosphere or in a stack testing reference method sample train), SO_3 will react spontaneously with water to form sulfuric acid (H_2SO_4, $H_2SO_4 \cdot H_2O$, or $H_2SO_4 \cdot 2H_2O$). Sulfuric acid is "condensable" particulate matter which is measured using Reference Method 202 used for determining PM_{10} and $PM_{2.5}$ emissions. In addition, some of the sulfur dioxide in the sample flue gas may dissolve in the Method 202 sample train and eventually react with water to form sulfuric acid. This unintended reaction of SO_2 to form condensable particulate matter creates particulate matter which is an artifact of the reference method. In this context "artifact" means something observed (i.e., condensable particulate matter) in a scientific investigation or experiment (i.e., the reference method test) that is not naturally present but occurs as a result of the investigative procedure or test method itself.

Because the proposed CTs have high excess oxygen levels, and because the CTs will be equipped with oxidation catalysts, relatively high percentages of SO_2 may be converted to SO_3. Based on information from the CT manufacturer, APS has concluded that the achievable long term PM, PM_{10}, and $PM_{2.5}$ emission rate for the proposed combined cycle CTs is 28.5 pounds per hour with duct firing, and 15.0 pounds per hour without duct firing. At the full rated heat input capacity for the proposed CTs of 4,680 mmBtu per hour when duct firing, this emission rate is equal to 0.0060 lb/mmBtu. At the full rated heat input capacity for the proposed CTs of 3,740 mmBtu per hour without duct firing, this emission rate is equal to 0.0040 lb/mmBtu.

Based on this analysis, APS proposes the following limits as the Best Available Control technology (BACT) for the control of particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions from the new GE 7HA.02 CTs.

1. Particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions may not exceed 28.5 pounds per hour, based on a 3-hour average with duct firing.
2. Particulate matter (PM), PM_{10}, and $PM_{2.5}$ emissions may not exceed 15.0 pounds per hour, based on a 3-hour average without duct firing.

Chapter 7. Volatile Organic Compound (VOC) Control Technology Review.

Like carbon monoxide (CO), volatile organic compound (VOC) is emitted from combustion turbines as a result of incomplete combustion. Therefore, the most direct approach for reducing VOC emissions and also reduce the other related pollutants is to improve combustion. Incomplete combustion also leads to emissions of organic hazardous air pollutants (HAP) such as formaldehyde. VOC and organic HAP emissions may also be reduced using post combustion air quality control systems.

7.1 BACT Baseline.

There are no NSPS or SIP requirements for stationary combustion turbines.

7.2 STEP 1. Identify All Available Control Technologies.

Table C7-1 is a summary of VOC emission limits for large natural gas-fired combined cycle CTs from the U.S. EPA's RACT/BACT/LAER database, the South Coast Air Quality Management District's (SCAQMD) BACT guidelines, and from recently issued permits.

TABLE C7-1. VOC BACT limits for natural gas-fired combined cycle CTs during normal operation.

Facility	State	Permit Date	CT Model or MW	Limit, ppmdv at 15% O_2	Averaging Period	Control Systems
Maple Creek Energy, LLC	IN	2023	GE 7HA.03 4,200 mmBtu/hr	1.0	3-hour	DLN, OC
Entergy Orange County Power Station	TX	2023	Mitsubishi M501JAC	2.0	3-hour	DLN, OC
Mountain State Clean Energy LLC	WV	2022	GE 7HA.02 or GE 7HA.03	2.0 / 1.0*	3-hour	DLN, OC
Nemadji Trail Energy Center	WI	2020	Siemens SGT6-8000 H	2.7 / 0.6*	168-hour	DLN, OC
Virginia Electric and Power Company-Warren	VA	2019	Mitsubishi M501GAC	1.6 / 0.7*	3-hour	DLN, OC
CPV Three Rivers, LLC	IL	2018	GE 7HA.02 CC CTs	10.8 / 4.4 lb/hour	3-hour	DLN, OC

Footnotes

DLN means dry low NO_x combustors; OC means oxidation catalyst system; WI means water injection.

* The first limit is with duct firing; the second limit is without duct firing..

Based on these recent decisions and a review of current VOC control technologies, the available control options for VOC emissions from natural gas-fired combined cycle CTs include the use of good combustion practices based on CT design and the use of oxidation catalysts as post combustion control systems. Good combustion practices include the use of dry low NO_x (DLN) combustion or water injection. Note that all of the CTs in Table A7-1 use good combustion practices consisting of DLN combustion in combination with oxidation catalysts to meet the VOC emission limits.

7.2.1 Good Combustion Practices.

Good combustion practices, including the use of water injection or dry low NO_x combustors is an effective method for controlling CO (and VOC) emissions from these CTs. These combustion technologies are described below.

7.2.1.1 Water Injection.

Water injection is the most widely used combustion control technology for aero derivative CTs with capacities less than 100 MW. Aeroderivative CTs are adapted from aerospace jet engine technology and are characterized by a lightweight, modular design. Uncontrolled, conventional CT combustors are “diffusion controlled” where fuel and air are injected separately. Combustion occurs locally and in non-uniform mixing conditions which result in hot spots that can produce high levels of NO_x. The injection of water directly into the combustion section lowers the peak flame temperature and reduces thermal NO_x formation. Injection rates for both water or steam are usually described by a water-to-fuel ratio, referred to as omega (Ω), given on a weight basis (i.e., pounds of water per pound of fuel). By controlling combustion conditions, this process minimizes NO_x, CO and VOC emissions.

A significant advantage of water injection for simple cycle CTs is the ability to achieve higher peak power output levels with water injection. The use of water injection increases the mass flow through the CT which increases power output, especially at high ambient temperatures when peak power is often needed from the CTs, but is limited by the high ambient air temperature. However, water injection is not an available combustion technology for the proposed CTs which are much larger heavy duty CTs.

7.2.1.2 Dry Low NO_x Combustors.

As noted above, uncontrolled CT combustors are diffusion controlled where fuel and air are injected separately. Combustion occurs locally and in non-uniform mixing conditions which result in hot spots that can produce high levels of NO_x. For large, heavy duty CTs, dry low NO_x (DLN) combustors are an advanced combustion technology which premixes air and natural gas prior to injection into the CT. When the DLN combustors are operating in the full premixed mode, the uniform mixture of combustion air and fuel reduces hot spots and significantly reduces peak flame temperature. This combustion technology results in improved combustion efficiency, reduced CO and VOC emissions, and reduced NO_x formation.

Each CT will be equipped with state-of-the-art DLN combustion systems. GE Vernova’s DLN family (DLN 2/2.6/2.6+/2.6e) of combustion systems enables GE Vernova’s H-class gas turbines to reduce NO_x emissions while enabling high plant efficiency and extending outage intervals. The DLN 2.6e maintains many of the elements of GE Vernova's DLN 2.6+ combustion system but introduces advanced premixing to the 7HA gas turbine combustor.

Like water injection, DLN combustors cannot achieve the full premix mode during periods of startup and shutdown. As a result, the CTs operate in diffusion combustion mode until sufficient air and fuel flow allow for full premix mode to occur. As a result, CO emissions can be elevated during startup and shutdown.

7.2.2 Oxidation Catalyst Systems.

The lowest CO (and VOC) emission levels have generally been achieved using oxidation catalysts installed as post combustion control systems. The typical oxidation catalyst is a rhodium or platinum (noble metal) catalyst on an alumina support material. This catalyst is typically installed in a reactor with flue gas inlet and outlet distribution plates. CO and VOC react with oxygen (O_2) in the presence of the catalyst to form carbon dioxide (CO_2) and water (H_2O) according to the following general equations:

$2CO$	$+ O_2$	$\rightarrow$	$2CO_2$	(Carbon Monoxide Oxidation)
$2C_nH_{2n+2}$	$+ (3n + 1)O_2$	$\rightarrow$	$2nCO_2 + (2n+2)H_2O$	(VOC Alkane Oxidation)
CH_2O	$+ O_2$	$\rightarrow$	$CO_2 + H_2O$	(Formaldehyde Oxidation)

The generally acceptable catalyst operating temperatures range from 450 – 1,250 °F, with the optimum temperature range of 700 - 1,100 °F. Below approximately 450 ^{o}F, catalyst activity (and oxidation potential) is negligible. For this reason, the oxidation catalyst air quality control systems also are not operational during periods of startup and shutdown (SU/SD) because the exhaust gas temperatures are too low for these systems to function as designed. As a result, VOC emissions may also be elevated during periods of startup and shutdown due to the inactivity of the oxidation catalyst systems.

7.3 STEP 2. Identify Technically Feasible Control Technologies.

Each of the available control options identified above including good combustion practices based on CT combustor design and oxidation catalyst systems are technically feasible VOC control technologies for the proposed combined cycle CT electric generating units.

7.4 STEP 3. Rank the Technically Feasible Control Technologies.

The highest level of control and lowest VOC emission rate from the proposed combined cycle CTs is the use of good combustion practices in combination with oxidation catalysts. The lowest permitted emission limit is for the Virginia Electric and Power Company – Warren facility for a Mitsubishi M501GAC CTs. The VOC limits include 1.6 ppmdv at 15% excess oxygen with duct firing, and 0.7 ppmdv at 15% excess oxygen without duct firing. Other emission limits for permitted facilities range from approximately 0.6 to 2.7 ppmdv at 15% O_2. The lower-ranked (less effective) control option is the use of good combustion practices based on CT design without oxidation catalysts.

7.5 STEP 4. Evaluate the Most Effective Controls.

The use of oxidation catalysts will cause a small back pressure increase to the CTs which will result in a small reduction in the CT efficiency. Oxidation catalysts will also increase the cost of electric power generated by reducing CT efficiency and increasing capital and O&M costs. However, these impacts are expected to be small. Therefore, it is appropriate that this strategy serve as the basis for establishing BACT for VOC emissions.

As noted above, the air quality control systems including the dry low NO_x combustion systems and the oxidation catalyst systems are not operational during periods of startup and shutdown (SU/SD). During periods of startup and shutdown, the DLN combustors cannot achieve the full premix mode and the exhaust gas temperatures are too low for the oxidation catalyst systems to function as designed. As a result, VOC emissions may be elevated during periods of startup and shutdown. For periods of startup and shutdown, APS proposes the use of good combustion practices designed to expeditiously startup and shutdown the CTs to minimize VOC emissions.

7.5.1 Startup and Shutdown Emissions.

The CT air pollution control systems including the SCR and oxidation catalyst systems are not operational during periods of startup and shutdown (SU/SD) because the exhaust gas temperatures are too low for these systems to function as designed. In addition, the DLN combustors cannot operate in the full premix mode until sufficient flue flow is delivered to allow for full fuel and air premixing. As a result, CO, NO_x, and VOC emissions may be elevated during periods of startup and shutdown.

The time required to startup and shutdown a combined cycle CT is limited by the temperatures inside the heat recovery steam generator (HRSG) and the steam turbine. Severe and potentially hazardous plant conditions can occur if the HRSG or steam turbine are heated too rapidly. As a result, combined cycle CTs have three types of startup events, designated as cold, warm, and hot startup. These startup are defined as follows:

> ***Hot Startup*** is defined as taking place within 8 hours after the previous shutdown. The typical duration is 30 minutes.
>
> ***Warm Startup*** is defined as taking place more than 8 hours but less than 72 hours after the previous shutdown. The typical duration is 60 minutes.
>
> ***Cold Startup*** is defined as taking place more than 72 hours after the previous shutdown. The typical duration is 70 minutes.

Cold startup events are generally limited to occurring after a major unit outage such as a scheduled unit maintenance outage or a significant unit malfunction. Conversely, warm and hot startup events can occur much more frequently and can, in many cases, occur interchangeably. Shutdown events are essentially the same after any type of startup event with a typical duration of 12 minutes.

7.6 STEP 5. Proposed Volatile Organic Compound (VOC) BACT Determination.

7.6.1 Proposed BACT for Normal Operation.

Based on this analysis, APS has concluded that the use of good combustion practices including the use of dry low NO_x combustors in combination with the use of oxidation catalysts represents the best available control technology (BACT) for the control of VOC emissions from the proposed GE Model 7HA.02 combined-cycle CTs. APS proposes the following limits as BACT for VOC emissions from these CTs:

1. Volatile organic compound (VOC) emissions may not exceed 12.1 pounds per hour, based on a 3-hour average with duct firing, when operated during periods other than startup/shutdown and tuning/testing.
2. Volatile organic compound (VOC) emissions may not exceed 5.0 pounds per hour, based on a 3-hour average without duct firing, when operated during periods other than startup/shutdown and tuning/testing.

7.6.2 Proposed BACT for Periods of Startup and Shutdown.

Please note that potential VOC emissions for each unit, expressed in tons per year, are based on the following combustion turbine design specifications:

1. Total VOC emissions during a cold startup event of 105 pounds.
2. Total VOC emissions during a warm or hot startup event of 70 pounds.
3. Total VOC emissions during a shutdown event of 55 pounds.
4. Total of 16 cold startup events in any consecutive 12-month period.
5. Total of 350 warm and hot startup events combined in any consecutive 12-month period.

Based on these design specifications, the potential startup and shutdown VOC emissions for each unit are equal to 23.2 tons per year, and the total potential VOC emissions for each unit, including normal operation, are equal to 52.2 tons per year. Therefore, limiting the total potential emissions for each unit to 52.2 tons per year will also ensure that the normal operation and SU/SD emissions are limited to represent BACT. Based on this analysis, APS proposes the following as BACT for the control of VOC emissions from the proposed GE 7HA.02 combined cycle CTs during periods of startup and shutdown.

1. The total number of cold startup events may not exceed 16 events in any consecutive 12-month period.
2. The total number of warm and hot startups events combined may not exceed 350 events in any consecutive 12-month period.

3. The total VOC emissions may not exceed 52.2 tons per year, based on a 12-month average.
4. “Hot startup” is defined as taking place within 8 hours after the previous shutdown. A hot startup is the period beginning with the ignition of fuel and ending 30 minutes later.
5. “Warm startup” is defined as taking place more than 8 hours but less than 72 hours after the previous shutdown. A warm startup is the period beginning with the ignition of fuel and ending 60 minutes later.
6. “Cold startup” is defined as taking place more than 72 hours after the previous shutdown. A cold startup is the period beginning with the ignition of fuel and ending 70 minutes later.
7. “Shutdown” is defined as the period beginning with the initiation of gas turbine shutdown sequence and lasting until fuel combustion has ceased.

Chapter 8. Greenhouse Gas (GHG) Emissions Control Technology Review.

On May 13, 2010, the U.S. EPA issued a final "tailoring" rule that establishes requirements for greenhouse gas (GHG) emissions from stationary sources under the Prevention of Significant Deterioration (PSD) program in 40 CFR §52.21. This rule sets thresholds for GHG emissions that establish when permits are required for new stationary sources under the PSD program. The final rule "tailors" the requirements of the PSD program to limit which facilities will be required to obtain PSD permits and meet substantive PSD program requirements for GHG emissions. After January 2, 2011, new major stationary sources that are subject to the PSD permitting program due to potential emissions of a pollutant other than GHGs would be subject to the PSD requirements for GHG emissions. GHG emission increases of 75,000 tons per year or more of total GHG, on a total CO_2 equivalent basis (CO_2e), will need to determine the Best Available Control Technology (BACT) for GHG emissions.

The final rule includes the following regulated GHG emissions:

1. Carbon dioxide (CO_2)
2. Methane (CH_4)
3. Nitrous oxide (N_2O)
4. Hydrofluorocarbons (HFCs)
5. Perfluorocarbons (PFCs)
6. Sulfur hexafluoride (SF_6)

From 40 CFR §98, Table A-1, the global warming potential for these pollutants are:

Name	Global Warming Potential (100 yr.)
1. Carbon dioxide (CO_2)	1
2. Methane (CH_4)	28
3. Nitrous oxide (N_2O)	265

The potential emission rate for each individual greenhouse gas is then multiplied by its global warming potential and summed to determine the total CO_2 equivalent emissions (CO_2e) for the source.

8.1 Project Operational Requirements.

The purpose of the Desert Sun Power Plant combined cycle electric generating units is to supply reliable, high-capacity electric service needed to serve the rapidly growing large customer load in Maricopa County, including data centers and other energy-intensive users. Demand from these customers has increased significantly in recent years and now exceeds the capacity that can be served by the existing electric generating infrastructure. These units are needed to provide firm, dispatchable electric power capable of operating during periods of grid stress and extreme weather conditions, ensuring system reliability and supporting continued economic development. These high-efficiency units will complement renewable electric power generation including solar and wind power by providing dependable capacity, fast response, and grid support needed to maintain stable service as the load of the APS system grows.

A critical component of this Project is that the proposed combined cycle units are very high efficiency, baseload units which can provide much-needed energy during any time of the day and for continuous periods, creating a strong complement to renewable energy resources such as solar. The proposed units will also provide dynamic voltage control for the electric grid. Dynamic voltage control is the ability of a generating resource to maintain voltage levels within acceptable limits. This Project will also provide system electric inertia (kinetic energy stored during the units' operation) and frequency response (the ability of a generating resource to aid balance between generation and load on the grid) necessary for electric system stability. Batteries and renewable energy systems such as wind and solar cannot provide this necessary grid support. These attributes of the proposed combined cycle units are critical when the electric supply resource portfolio includes more and more intermittent, renewable resources such as wind and solar.

8.2 Potential Greenhouse Gas (GHG) Emissions.

GHG emissions from natural gas-fired CTs include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). The federal *Mandatory Greenhouse Gas Reporting Requirements* under 40 CFR Part 98 requires reporting of greenhouse gas (GHG) emissions from large stationary sources. Under 40 CFR Part 98, facilities that emit 25,000 metric tons or more per year of GHG emissions are required to submit annual reports to EPA. Table C-1 of this rule includes default emission factors for CO_2. The CO_2 emission factor for natural gas combustion is 53.06 kg per mmBtu, equal to 116.98 pounds per million Btu, based on the higher heating value (HHV) of natural gas.

Methane (CH_4) emissions result from incomplete combustion of natural gas. The federal *Mandatory Greenhouse Gas Reporting rule*, 40 CFR Part 98, Table C-2 lists a methane emission factor for natural gas combustion of 0.001 kg/mmBtu (0.0022 lb/mmBtu). The potential emission rate for methane is then multiplied by its global warming potential of 28 to determine the total CO_2e emissions, equal to 0.062 lb CO_2e per mmBtu of heat input.

Nitrous oxide (N_2O) emissions from gas turbines result primarily from low temperature combustion. The federal *Mandatory Greenhouse Gas Reporting rule,* 40 CFR Part 98, Table C-2 lists a default N_2O emission factor for natural gas combustion of 0.0001 kg/mmBtu (0.00022 lb/mmBtu). The potential emission rate for N_2O is then multiplied by its global warming potential of 265 to determine the total CO_2e emissions, equal to 0.058 lb CO_2e per mmBtu of heat input.

Potential GHG emissions for each combined cycle CT based on 8,760 hours per year of continuous operation, including 2,000 hours per year of maximum operation with duct firing are summarized in Table C8-1. It is important to note that the emission rates for CO_2 and GHG emissions, expressed in pounds per million Btu of heat input (lb/mmBtu), are NOT elevated during periods of startup and shutdown. Therefore, total emissions may simply be based on the heat input of the CTs at their maximum rated heat input capacity during normal operation. ***Because CO_2 emissions account for 99.9% of the GHG emissions from these CTs, this control technology review for GHG emissions will focus on CO_2 emissions.***

TABLE C8-1. Potential GHG emissions for each CT based on the proposed emission limits in this application.

Pollutant		Emission Factor	Total GHG Emission Factor		NORMAL OPERATION WITHOUT DUCT BURNERS			NORMAL OPERATION WITH DUCT BURNERS			TOTAL
					Heat Input		Emissions	Heat Input		Emissions	
		lb/mmBtu	CO_2e Factor[4]	lb/mmBtu	mmBtu/hr	mmBtu/yr	ton/year	mmBtu/hr	mmBtu/yr	ton/year	ton/year
Carbon Dioxide	CO_2	116.98	1	116.976	3,740	25,282,400	1,478,718	4,750	9,500,000	555,636	2,034,354
Methane	CH_4	0.0022	28	0.062	3,740	25,282,400	780	4,750	9,500,000	293	1,074
Nitrous Oxide	N_2O	0.00022	265	0.058	3,740	25,282,400	739	4,750	9,500,000	278	1,016
TOTAL GHG EMISSIONS, AS CO_2e				**117.1**	**3,740**	**25,282,400**	**1,480,237**	**4,750**	**9,500,000**	**556,207**	**2,036,444**

Footnotes

The emission rates for CO_2 and GHG emissions, expressed in pounds per million Btu of heat input (lb/mmBtu), are NOT elevated during periods of startup and shutdown. Therefore, the total potential emissions may simply be based on the heat input of the CTs at their maximum rated heat input capacity during normal operation.

The annual heat input during normal operation is based on 8,760 hours per year of operation, including 2,000 hours per year of duct firing. The annual heat input without duct firing is equal to 3,740 mmBtu/hr and 6,760 hours of operation, equal to 25,282,400 mmBtu per year. The annual heat input with duct firing is equal to 4,750 mmBtu/hr and 2,000 hours of operation, equal to 9,500,000 mmBtu per year.

8.3 BACT Baseline.

8.3.1 Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units, 40 CFR 60 Subpart TTTTa.

On May 9, 2024, the U.S. EPA published a final rule establishing greenhouse gas standards and guidelines for new and reconstructed stationary combustion turbine electric generating units under 40 CFR 60, Subpart TTTTa. New stationary combustion turbines that commence construction or reconstruction after May 23, 2023 and meet the relevant applicability criteria will be subject to 40 CFR 60, subpart TTTTa.

For new and reconstructed fossil fuel-fired combustion turbines, the final rule creates three subcategories based on the function the combustion turbine serves. In accordance with 40 CFR § 60.5580a, *Base load combustion turbine* means "a stationary combustion turbine that supplies more than 40 percent of its potential electric output as net-electric sales on both a 12-operating month and a 3-year rolling average basis." These proposed CTs will be base load combustion turbines. The applicable emission limits for base load combustion turbines in Table 1 to Subpart TTTTa are included below. The proposed units at the Desert Sun Power Plant will be ***Base load combustion turbines*** with a rating of more than 2,000 mmBtu/hr. The applicable CO_2 emission standard for these units is 800 pounds of CO_2 per megawatt-hour (lb CO_2/MWh) of gross electric output, based on a 12-month average.

Table 1 to Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After May 23, 2023 (Gross or Net Energy Output-Based Standards Applicable as Approved by the Administrator)

[NOTE: NUMERICAL VALUES OF 1,000 OR GREATER HAVE A MINIMUM OF 3 SIGNIFICANT FIGURES AND NUMERICAL VALUES OF LESS THAN 1,000 HAVE A MINIMUM OF 2 SIGNIFICANT FIGURES]

Affected EGU category	CO_2 emission standard
Base load combustion turbines	For 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a. For 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (100 to 150 lb CO_2/MWh) of gross energy output; or 42 to 64 kg CO_2/MWh (97 to 139 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Intermediate load combustion turbines	530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 700 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output as determined by the procedures in § 60.5525a.
Low load combustion turbines	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in § 60.5525a.

Please note that on June 17, 2025, the U.S. EPA published a proposed rule to repeal all GHG emissions standards for fossil fuel-fired power plants. The EPA is proposing that the Clean Air Act (CAA) requires it to make a finding that GHG emissions from fossil fuel-fired power plants contribute significantly to dangerous air pollution, as a predicate to regulating GHG emissions from those plants. The EPA is further proposing to make a finding that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution. The EPA is also proposing, as an alternative, to repeal the emission standards under Subpart TTTTa that includes the emission guidelines for existing fossil fuel-fired steam generating units, the carbon capture and sequestration/storage (CCS)-based standards for coal-fired steam generating units undertaking a large modification, and the CCS-based standards for new base load stationary combustion turbines.

8.4 BACT Control Technology Determinations.

Table C8-2 is a summary of BACT determinations from the U.S. EPA's RACT/BACT/LAER Clearinghouse and other recent permit decisions for combined cycle CT electric generating units. Emission limits range from 826 to 852 lb/MWh. In addition, the BACT determination for the Entergy Orange County Power Station in Texas is the "Exclusive use of natural gas and a blend of 30 vol% hydrogen with natural gas as fuels, using a high efficiency combined cycle power generation method".

The Standards of Performance for Greenhouse Gas Emissions for *Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units*, 40 CFR 60 Subpart TTTTa requires Base load combustion turbines to achieve an emission rate of 800 to 1,250 lb CO_2/MWh based on a 12-operating month average.

TABLE C8-2. Recent GHG BACT limits for natural gas-fired combined-cycle gas turbines.

Facility	State	Permit Date	CT Model or MW	Limit, lb CO_2e/MWh(g)	Averaging Period
Maple Creek Energy, LLC	IN	2023	GE 7HA.03	826	12-month
Entergy Orange County Power Station	TX	2023	Mitsubishi M501JAC	Exclusive use of nat. gas and a blend of 30 vol% hydrogen with nat. gas, using a high efficiency combined cycle power generation.	
Mountain State Clean Energy LLC	WV	2022	GE 7HA.02 or GE 7HA.03	852	12-month
Lincoln Land Energy Center	IL	2022	Siemens SGT6-8000 H	850	12-month
Nemadji Trail Energy Center	WI	2020	Siemens SGT6-8000 H	850	12-month
CPV Three Rivers, LLC	IL	2018	GE 7HA.02 CC CTs	925	12-month

8.5 STEP 1. Identify All Potential Control Technologies.

The first step in a top-down BACT analysis is to identify all "available" control options. Available control options are those control technologies or techniques with a practical potential for application to the emissions unit and pollutant being evaluated. Air pollution control technologies and techniques include the application of production process or available methods, systems, controls, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for the affected pollutant.

Recent BACT emission limits have been expressed on a pound per MWh of electric output basis (either gross or net output) and/or a fuel composition requirement. The averaging periods for these emission limits are long term, 12-month limits. The available technologies for the control of CO_2 emissions from recently permitted combined cycle natural gas-fired CTs identified in this database includes the use of low carbon containing fuels and the use of energy efficient processes.

CO_2 emissions result from the oxidation of carbon in the fuel. When combusting natural gas, this reaction is responsible for much of the heat released in the combustion turbine and is therefore unavoidable. Broadly, there are four potential control options for reducing CO_2 emissions from these CTs:

1. **The use of low carbon containing or lower emitting primary fuels,**
2. **Good combustion, operating, and maintenance practices, including,**
    a. Steam injection,
    b. Water injection,
    c. Dry Low NO_x combustion.
3. **The use of energy efficient processes and technologies, including,**
    a. Efficient simple cycle CTs,
    b. Combined cycle CTs,
    c. Reciprocating internal combustion engine (RICE) generators,
    d. Energy storage option.
4. **Carbon capture and sequestration (CCS) as a post combustion control system.**

With respect to the use of energy efficient processes and technologies, as stated by the Bay Area Air Quality Management District in the Statement of Basis for the Russell City Energy Center, “The only effective means to reduce the amount of CO_2 generated by (a) fuel-burning power plant is to generate as much electric power as possible from the combustion, thereby reducing the amount of fuel needed to meet the plant’s required power output.” Energy efficient processes and technologies include reciprocating internal combustion engines (RICE), as well as efficient simple cycle gas (combustion) turbines (CT) and combined-cycle CTs. There are also various energy storage systems, including battery storage, liquid air energy storage (LAES), flywheel energy storage (FES), compressed air energy storage (CAES), and pumped hydroelectric storage.

APS is proposing to install natural gas-fired combined cycle CTs to meet the specific purpose and need of these baseload electric generating units. The use of simple cycle CTs or other energy storage options in place of these proposed combined cycle CTs would change the project in such a fundamental way that the requirement to use these technologies would redefine the design of the Project. As EPA noted in its guidance, *U.S. EPA, EPA-457/B-11-001, PSD and Title V Permitting Guidance for Greenhouse Gases 26 (Mar. 2011)*, page 26:

> While Step 1 is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.

8.5.1 Use of Low Carbon Containing or Lower Emitting Primary Fuels.

EPA's guidance document "*PSD and Title V Permitting Guidance for Greenhouse Gases*" notes that because the CAA includes "clean fuels" in the definition of BACT, clean fuels which would reduce GHG emissions but do not result in the use of a different primary fuel type or a redesign of the source should be considered in the BACT analysis. Table C8-3 is a summary of the CO_2 emission rate for coal, distillate fuel oil, and natural gas. With respect to the use of lower emitting or low carbon containing "clean" fuels, APS is proposing the use of natural gas as the primary fuel for these CTs. Because natural gas is the lowest CO_2 emitting fossil fuel available for this Project, further evaluation of clean fuels is not necessary.

TABLE C8-3. Potential CO_2 emissions for various fossil fuels.

Fuel	CO_2 Emission Rate, lb/mmBtu
Bituminous Coal	205.9
Subbituminous Coal	213.9
Distillate Fuel Oil	162.7
Natural Gas	116.9

Footnotes

The CO_2 emission rates are from *Mandatory Greenhouse Gas Reporting Requirements* 40 CFR Part 98.

8.5.1.1 Hydrogen Fuel.

In the preamble to the U.S. EPA's proposed *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*, 40 CFR 60 Subpart TTTTa, the EPA noted that the combustion of hydrogen (H_2) as a fuel in CTs would produce essentially zero direct CO_2 emissions, and EPA evaluated a number of cofiring scenarios for baseload electric generating units in the proposed rule. However, EPA also noted in the preamble that the manufacture of hydrogen can generate GHG emissions. And EPA did not propose cofiring of hydrogen for low load peaking units such as these proposed CTs.

There are a number of complications to firing hydrogen in combustion turbines. As EPA stated in the Technical Support Document (TSD) *Hydrogen in Combustion Turbine Electric Generating Units*[8] "Perhaps the most significant challenge is that the flame speed of hydrogen gas is an order of magnitude higher than that of methane; at hydrogen blends of 70 percent or greater, the flame speed is essentially tripled compared to pure natural gas. A higher flame speed can lead to localized higher temperatures, which can increase thermal stress on the turbine's components as well as increase thermal NO_x emissions."

Hydrogen production methods include gasification of coal, steam methane reforming, methane pyrolysis, and electrolysis of water, as well as hydrogen derived from biomass or refuse. Without carbon capture and sequestration, producing hydrogen from coal and natural gas will itself produce GHG emissions. Production by electrolysis would have essentially zero GHG emissions, but it requires electricity to electrolyze water into hydrogen and oxygen. According to the same EPA TSD, "Specific to the electricity source, electrolysis production prices are estimated to be $5.58/kg, $5.96/kg, and approximately $9.00/kg for nuclear, wind, and solar electrolysis, respectively." At a higher heating value of 61,100 Btu/lb, this is equal to costs of $42 to $67 per million Btu of heat input. This is more than 10 times the current cost of natural gas.

While the proposed GE 7HA.02 CTs are capable of cofiring up to 50% hydrogen, there is no source of hydrogen currently available for use in these CTs. The use of hydrogen as a fuel in these CTs would fundamentally change the proposed project. As EPA notes in its GHG BACT guidance, *U.S. EPA, EPA-457/B-11-001, PSD and Title V Permitting Guidance for Greenhouse Gases 26 (Mar. 2011)*, page 26:

> While Step 1 is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.
>
> In assessing whether an option would fundamentally redefine a proposed source, EPA recommends that permitting authorities apply the analytical framework recently articulated by the Environmental Appeals Board. Under this framework, a permitting authority should look first at the administrative record to see how the applicant defined its goal, objectives, purpose or basic design for the proposed facility in its application. The underlying record will be an essential component of a supportable BACT determination that a proposed control technology redefines the source.

Because the use of hydrogen as a fuel would fundamentally redefine the nature of the Project as stated in this application, hydrogen fuel may be eliminated in Step 1 because the required use of hydrogen as a fuel which is not available at the Desert Sun Power Plant would constitute a redefinition of the source.

[8] *Hydrogen in Combustion Turbine Electric Generating Units*, Technical Support Document, Docket ID No. EPA-HQ-OAR-2023-0072, U.S. EPA Office of Air and Radiation, May 23, 2023.

8.5.2 Good Combustion, Operating, and Maintenance Practices.

Combustion turbines use different combustion technologies to enhance performance or reduce emissions. Combustion technologies for CTs include diffusion flame combustion with water injection, diffusion flame combustion with steam injection, and lean premix combustion using dry low NO_x combustion.

8.5.2.1 Water and Steam Injection.

GE does not offer the proposed 7HA.02 CTs with water or steam injection. Therefore, water and steam injection are not an available control option for the proposed CTs and is therefore not a control option.

8.5.2.2 Dry Low NO_x Combustion.

For large, heavy duty CTs, DLN combustors are an advanced combustion technology which premixes air and natural gas prior to injection into the CT. When the DLN combustors are operating in the full premixed mode, the uniform mixture of combustion air and fuel reduces hot spots and reduces peak flame temperature. This combustion technology results in improved combustion efficiency which will minimize CO_2 emissions.

Each CT will be equipped with state-of-the-art DLN combustion systems. GE Vernova's DLN family (DLN 2/2.6/2.6+/2.6e) of combustion systems enables GE Vernova's H-class gas turbines to reduce NO_x emissions while enabling high plant efficiency and extending outage intervals. The DLN 2.6e maintains many of the elements of GE Vernova's DLN 2.6+ combustion system but introduces advanced premixing to the 7HA gas turbine combustor.

8.5.3 Use of Energy Efficient Processes and Technologies.

The following section discusses simple cycle CTs, reciprocating internal combustion engine (RICE) electric generating units, and various energy storage technologies. However, these technologies are not control technologies. The use of simple cycle CTs, RICE electric generating units, and energy storage options would change the project in such a fundamental way that the requirement to use these technologies would redefine the design of the Project.

8.5.3.1 Simple Cycle CTs.

The proposed combined cycle CTs are being constructed to provide baseload electric generating capacity. The use of simple cycle CTs would change these baseload, combined cycle CTs in such a fundamental way that these units could not meet their stated purpose of baseload power electric generating capacity. As noted above, EPA states in its GHG BACT guidance, *U.S. EPA, EPA-457/B-11-001, PSD and Title V Permitting Guidance for Greenhouse Gases (Mar. 2011)* that while Step 1 is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility. But in this case, simple cycle CTs would actually have a higher CO_2 emission rate and would therefore be a less effective control technology and can therefore also be eliminated in Step 2.

8.5.3.2 Reciprocating Internal Combustion Engine (RICE) Generators.

If the largest available RICE electric generating units of approximately 19 MW were used, this power plant would need at least thirty (30) RICE engines for each combined cycle CT, or more than 60 engines for both combined cycle units. This would be a far more complex power plant to construct and operate. While RICE electric generating units are not a control technology, RICE are further evaluated in Step 2 of the BACT analysis. And like simple cycle CTs, RICE electric generating units would actually have a higher CO_2 emission rate and would therefore be a less effective control technology.

8.5.3.3 Energy Storage Options.

A number of energy storage technologies may be available including batteries, compressed air energy storage (CAES), liquid air energy storage (LAES), pumped hydro, and flywheels. When considering energy storage options as a GHG emissions control technology in Step 1 of this analysis, it is important to point out that energy *storage* options are fundamentally different than the energy *generation* project being proposed by APS. In short, incorporating energy storage into the proposed Project is not an available control option because these options would fundamentally redefine the source.

In the U.S. EPA's Response to Comments on the Red Gate PSD Permit for GHG Emissions, PSD-TX-1322-GHG, February 2015,[9] issued for a peaking facility to be comprised of reciprocating internal combustion engines (RICE), EPA determined that "energy storage cannot be required in the Step 1 BACT analysis as a matter of law." And in the U.S. EPA Environmental Appeals Board (EAB) decision regarding the APS Ocotillo Power Plant in 2016, the EAB concluded that replacing part or all of the proposed electric power generation with energy storage fundamentally changed the project design and therefore the permitting authority did not err in not considering energy storage as an available technology, stating[10]:

> In sum, Maricopa County's characterization of Ocotillo's project purpose and inherent design is consistent with the record materials, and its BACT analysis incorporated a "hard look" at Arizona Public Service's business purpose. Accordingly, Maricopa County did not abuse its discretion in concluding that pairing energy storage with the proposed combustion turbines at the Ocotillo facility would "redefine the source."

The purpose of the Ocotillo Modernization Project and the Red Gate Project were to provide power for renewables and transmission grid support. EPA determined that "energy storage first requires separate generation and the transfer of the energy to storage to be effective . . . [it] is a fundamentally different design than a RICE resource that does not depend upon any other generation source to put energy on the grid." *Id.* Energy storage could not meet that production purpose for the duration or scale needed. *Id.* at 2-3. As EPA

[9] *Response to Public Comments* for the South Texas Electric Cooperative, Inc. – Red Gate Power Plant PSD Permit for Greenhouse Gas Emissions, PSD-TX-1322-GHG (Nov. 2014), http://www.epa.gov/region6/6pd/air/pd-r/ghg/stec-redgate-resp2sierra-club.pdfNov%2014 .

[10] U.S. EPA EAB PSD Appeal No. 16-01, ORDER DENYING REVIEW, September 1, 2016, page 346.

correctly observed, "[t]he nature of energy storage and the requirement to replenish that storage with another resource goes against the fundamental purpose of the facility." *Id.* at 3.

Similarly, in another PSD permit for a peaking facility for the Shady Hills Generating Station consisting of natural gas-fired simple cycle CTs (Jan 2014), EPA also concluded that energy storage would not meet the business purpose of the facility and therefore should not be considered in the BACT analysis. [11]

It is also important to note that energy storage technologies are not "zero emissions" technologies. The "round trip" energy efficiency of battery energy storage systems (BESS) is typically 80 to 90%. Other types of energy storage systems are even less. Therefore, while storage technologies may have near zero emissions at the site, the technology simply stores energy produced elsewhere, and then delivers it back to the grid, but at a net loss.

8.5.3.4 Battery Energy Storage Systems (BESS).

The Moss Landing Battery Storage Project is one of the largest grid connected battery energy storage facilities in the U.S. Installed at the retired Moss Landing power plant site in California, the facility has a 400 MW power output and 1,600 MWh of total energy capacity. Note that there was a significant fire at this facility in January 2025. One of the largest BESS systems in the world is the 15.1 GWh (15,100 MWh) BESS project by BYD Energy Storage and Saudi Electricity Company in Saudi Arabia. Even this extremely large BESS system of 15,100 MWh of energy storage can only provide the equivalent of about 13 hours of electric generation that these two combined cycle CTs can provide. And the Moss Landing facility could only provide the total energy output of these proposed combined cycle CTs for less than 2 hours. Thus, even these large BESS facilities cannot meet the basic purpose and need of these proposed CTs because this storage facility cannot provide the sustained, continuous electric generating capacity required. Therefore, the battery storage option may be eliminated at Step 1 of this BACT analysis because it would not meet the business purpose of these CTs[12], thereby redefining the source.

On April 21, 2022, the U.S. EPA issued a draft technical white paper on control techniques and measures that could reduce GHG emissions from new stationary CTs entitled *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units*, April 21, 2022. This emerging technologies document discusses the successful integration of short-term storage with natural gas-fired CTs at two 50-MW peaking plants operated by Southern California Edison (SCE). In 2017, the Norwalk and Rancho Cucamonga Generating Stations began operating the world's first "Hybrid Enhanced Gas Turbine systems". The energy storage comes from co-located 10-MW/4.3-MWh lithium-ion

[11] Responses to Public Comments, Draft Greenhouse Gas PSD Air Permit for the Shady Hills Generating Station at 10-11 (Jan 2014), http://www.epa.gov/region04/air/permits/ghgpermits/shadyhills/ShadyHillsRTC%20_011314.pdf.

[12] See the U.S. EPA's *Response to Public Comments* for the South Texas Electric Cooperative, Inc. – Red Gate Power Plant PSD Permit for Greenhouse Gas Emissions PSD-TX-1322-GHG, page 7. http://www.epa.gov/region6/6pd/air/pd-r/ghg/stec-redgate-final-rtc.pdf. EPA states with respect to the use of batteries as a BACT control option, "Thus, the option may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the project – to provide up 225MW of energy for necessary time periods – and it may also be eliminated at Step 2 of the BACT analysis because it does not meet the technical requirements of the project – to provide such power for multiple days."

batteries that pull excess renewable energy from the grid and then provide energy during peak demand. Note that these batteries are not required under the facility's permits for BACT.

This document states that "energy storage allows combustion turbines to minimize starts and stops and operate more continuously at optimal efficiency, both of which reduce GHG emissions." The battery storage at the two California facilities is charged by excess renewable power pulled from the grid as opposed to being charged by turbines on site. APS already has battery energy storage systems (BESS) co-located at solar energy installations in the area. Co-locating batteries at this new electric generating station to be charged by the CTs would actually *increase* GHG emissions from the units as compared to operation of the CTs alone because of the inherent round-trip efficiency losses for BESS.

8.5.3.5 Liquid Air Energy Storage (LAES).

Liquid air energy storage (LAES), also called cryogenic energy storage (CES), uses low temperature (cryogenic) liquids such as liquid air to store energy. This technology is being developed by Highview Power Storage in the United Kingdom. According to their website, work is now underway at Carrington; a 50MW / 300MWh plant at Trafford Energy Park near Manchester, UK. We are not aware of any commercially operating LAES facilities on the electric power output scale of the proposed Project. The "round trip" energy efficiency of LAES is expected to be 50 – 60%. Therefore, like batteries, the LAES option may be eliminated at Step 1 of the BACT analysis because it would not meet the business purpose of the Project, which is to generate and provide to the grid 748 MW of electricity as needed.

8.5.3.6 Flywheel Energy Storage (FES).

Flywheel energy storage (FES) uses electric energy input to spin a flywheel and store energy in the form of rotating kinetic energy. An electric motor-generator uses electric energy to accelerate the flywheel to speed. When needed, the energy is discharged by drawing down the kinetic energy using the same motor-generator. Because FES incurs limited wear even when used repeatedly, FES are best used for low energy applications that require many cycles such as for uninterruptible power supply (UPS) applications. We are not aware of large FES systems installed to date that have the power output or energy storage comparable to these proposed CTs. Therefore, like batteries and LAES, the flywheel energy storage option has not been developed on a similar scale and may therefore be eliminated at Step 1 of the BACT analysis.

8.5.3.7 Compressed Air Energy Storage (CAES).

Compressed air energy storage (CAES) stores compressed air in suitable underground geologic structures when off-peak power is available, and the stored high-pressure air is returned to the surface to produce power when generation is needed during peak demand periods. The round-trip energy efficiency of CAES is also expected to be approximately 50 – 60%. Two operating CAES plants include a 110 MW plant in McIntosh, Alabama (1991) and a 290 MW plant in Huntorf, Germany (1978). Both plants store air underground in excavated salt caverns produced by solution mining. Other geological structures such as basalt flows may also be feasible CAES geologic formations. However, the Desert Sun Power Plant does not have any suitable geological structures in the vicinity of the plant. Therefore, like the other energy storage options, the CAES option may be eliminated at Step 1 of the BACT analysis because it would not meet the purpose of the Project, and can also be eliminated at Step 2 as technically infeasible.

8.5.3.8 Pumped Hydroelectric Storage.

Pumped hydroelectric storage projects move water between two reservoirs located at different elevations to store energy and generate electricity. When electricity demand is low, excess electric generating capacity is used to pump water from a lower reservoir to an upper reservoir. When electricity demand is high, the stored water is released from the upper reservoir to the lower reservoir through a turbine to generate electricity. Pumped storage projects have relatively high round trip efficiencies of 70 to 80%. However, there are no available water reservoirs at or near the proposed Desert Sun Power Plant, and water resources in the Phoenix area are limited. Therefore, this technology is not an "available control option" and may be eliminated as a BACT option in Step 1 of the BACT analysis.

8.6 STEP 2. Identify Technically Feasible Control Technologies.

Step 2 of the BACT analysis involves the evaluation of the identified available control technologies to determine their technical feasibility. Generally, a control technology is technically feasible if it has been previously installed and operated successfully at a similar emission source. In addition, the technology must be commercially available for it to be considered as a candidate for BACT.

Potential CO_2 controls for these CTs include the use of low carbon containing fuels, energy efficient processes and technologies including efficient simple cycle CTs, reciprocating internal combustion engines (RICE), and the use of post combustion control systems, including carbon capture and sequestration (CCS).

8.6.1 Lower Emitting Primary Fuels.

EPA's guidance document "*PSD and Title V Permitting Guidance for Greenhouse Gases*" notes that because the CAA includes "clean fuels" in the definition of BACT, clean fuels which would reduce GHG emissions but do not result in the use of a different primary fuel type or a redesign of the source should be considered in the BACT analysis. Table 9-3 is a summary of the CO_2 emission rate for coal, distillate fuel oil, and natural gas. With respect to the use of lower emitting or low carbon containing "clean" fuels, APS is proposing the use of natural gas as the primary fuel for these CTs. Because natural gas is the lowest CO_2 emitting fossil fuel available for this Project, further evaluation of clean fuels is not necessary.

As noted in Step 1, because the use of hydrogen as a fuel would fundamentally redefine the nature of the Project, hydrogen fuel may be eliminated in Step 1 because the required use of hydrogen as a fuel which is not available at the Redhawk Power Plant would constitute a redefinition of the source.

8.6.2 Energy Efficient Processes and Technologies.

The use of energy efficient processes and technologies is a technically feasible CO_2 control option. As stated by the Bay Area Air Quality Management District in the Statement of Basis for the Russell City Energy Center, "The only effective means to reduce the amount of CO_2 generated by (a) fuel-burning power plant is to generate as much electric power as possible from the combustion, thereby reducing the amount of fuel needed to meet the plant's required power output." Energy efficient processes and technologies include efficient simple cycle gas turbines, as well as reciprocating internal combustion engines (RICE), and combined-cycle gas turbines.

8.6.2.1 High Efficiency Simple Cycle Combustion Turbines.

APS is proposing to install two (2) GE Vernova Model 7HA.02 natural gas-fired combined cycle CTs for these baseload electric generating units. Simple cycle CTs would not meet the purpose and need of these baseload electric generating units, and in any case they would actually have a higher CO_2 emission rate than combined cycle units.

8.6.2.2 Reciprocating Internal Combustion Engines.

Reciprocating internal combustion engines (RICE) are well-suited for peak electric generating capacity but are not technically feasible for baseload electric generating units. And like simple cycle CTs, RICE electric generating units would actually have a higher CO_2 emission rate and would therefore be a less effective control technology.

8.6.3 Good Combustion, Operating, and Maintenance Practices.

Good combustion and operating practices are a potential control option by improving the efficiency of any combustion related generating technology. Good combustion practices include the use of high efficiency dry low NOx combustion systems and the proper maintenance and tune-up of the CTs in accordance with the manufacturer's specifications.

8.6.4 Carbon Capture and Sequestration (CCS).

There are three approaches for Carbon Capture and Sequestration (CCS), including pre-combustion capture, post-combustion capture, and oxy-fuel combustion[13]. Pre-combustion capture is applicable primarily to fuel gasification plants, where solid fuel such as coal is converted into gaseous fuels. The conversion process could allow for the separation of the carbon containing gases for sequestration. Pre-combustion capture is not technically feasible for these CTs which are based on natural gas combustion that does not require gas conversion.

Oxy-combustion is the combustion of fuels with nearly pure oxygen and recycled flue gas instead of air. The resultant flue gas is primarily carbon dioxide (CO_2) which facilitates the capture of high-purity CO_2 without the need for a post-combustion scrubber. However, oxy-fuel combustion is not commercially available for combustion turbine applications.

Post-combustion CCS is theoretically applicable for combined cycle CT power plants. However, in contrast to readily available high-efficiency combined cycle CT technologies, we are not aware of any large combined cycle units that are equipped with CCS in the U.S.

A post combustion CCS system involves three steps: 1) Capturing CO_2 from the emissions unit, 2) Transporting the CO_2 to a permanent geological storage site, and 3) Permanently storing the CO_2.

Before CO_2 emitted from these CTs can be sequestered, it must be captured as a relatively pure gas. CO_2 may be captured from the CT exhaust gas using adsorption, physical absorption, chemical absorption, cryogenic separation, gas membrane separation, and mineralization. Many of these methods are either still

[13] Intergovernmental Panel on Climate Change (IPCC), 2005.

in development or are not suitable for treating CT flue gas due to the characteristics of the exhaust stream. The low concentration of CO_2 in natural gas-fired CTs adds to the challenge of CO_2 capture over coal-fired power plants. The CTs proposed for this Project are expected to contain approximately 3 to 5% CO_2 by volume in the flue gas exhaust. This concentration is much lower than coal-fired power plants, where the CO_2 concentration is typically 12 to 15%. As a result, there are a number of serious operational challenges and additional equipment which would be required for these natural gas-fired CTs because of the variable exhaust gas flow and low CO_2 concentration. These challenges and additional equipment would have significant impacts on the operation of these CTs, including significant impacts to the total Project cost, significant impacts to the Project's net electric generating capacity, and significant impacts to ramp rates and response times for the CTs.

Post-combustion carbon capture has been demonstrated on a slipstream from a combined cycle CT exhaust at NextEra Energy's (formerly owned and operated by Florida Power and Light) natural gas power plant in Bellingham, MA. This plant captures a 40 MW slipstream from a combined cycle CT, equal to about 365 short tons per day of CO_2. However, each of these proposed CTs could produce more than 5,500 tons of CO_2 per day per CT, or more than 11,000 tons per day for both CTs combined. This is thirty (30) times the size of the CO_2 capture system at the Bellingham Energy Center.

As noted in the POWER article, *Commercially Available CO_2 Capture Technology*, Dennis Johnson; Satish Reddy, PhD; and James Brown, PE, (available at www.powermag.com/coal/2064.html), Fluor Corporation has developed an amine-based post-combustion CO_2 capture technology called Econamine FG Plus (EFG+). There are more than 25 licensed plants worldwide that employ the EFG+ technology — from steam-methane reformers to CT power plants.

Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is the preferred option because it is the most mature and well-documented technology, and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes. Post-combustion capture using MEA is also the only process known to have been previously demonstrated in practice on CTs. Therefore, MEA is the only carbon capture technology considered in this analysis.

In 2003, Fluor and British Petroleum (BP) completed a joint feasibility study that examined capturing CO_2 from eleven simple cycle CTs at BP's Central Gas Facility (CGF) gas processing plant in Alaska (Hurst & Walker, 2005; Simmonds et al., 2003). This project was not actually implemented. The absorption of CO_2 by MEA is a reversible exothermic reaction. To capture CO_2 using MEA, the turbine exhaust gas must be cooled to about 50 ^{o}C (122 ^{o}F) to improve absorption and minimize solvent loss due to evaporation. In the feasibility study for the CGF, the CT flue gas was to be cooled by a heat recovery steam generator (HRSG) to complete most of the cooling, followed by a direct contact cooler (DCC). Hurst & Walker (2005) found that the DCC alone would be insufficient for the CTs due to the high exhaust gas temperature of 480 - 500 ^{o}C (900 – 930 ^{o}F).

In a carbon capture system, after the MEA is loaded with CO_2 in the absorber, it would be sent to a stripper where it is heated to reverse the reaction and liberate the CO_2. In the CGF facility study, heat for this regeneration stage was to have come from the steam generated in the HRSG, with excess steam to be used to generate electricity.

As noted above, a post combustion CCS system involves three steps:

1) Capturing CO_2 from the emissions unit,
2) Transporting the CO_2 to a permanent geological storage site, and
3) Permanently storing the CO_2.

With respect to the second and third steps, the site for the Desert Sun Power Plant does not have any nearby carbon sequestration sites available. According to the U.S. Geologic Survey (USGS) *Geologic Carbon Dioxide Sequestration Interactive Map*, the closest possible sites are the Eastern Great Basin north and west of the Colorado River in Nevada and in the northwest corner of Arizona, and the San Juan Basin in northwest New Mexico. The closest of these areas is more than 200 miles from the Desert Sun Power Plant site location. And far more studies and evaluation would be necessary to determine if these areas are available AND feasible to be used for long term CO_2 sequestration. These distances present severe technical feasibility problems to transporting and permanently sequestering up to 4,000,000 tons of CO_2 annually from these combined cycle CTs.

8.6.5 Conclusions regarding the technically feasible control options.

Table C8-4 identifies the technically feasible and technically infeasible control technologies for the control of GHG emissions from the proposed CTs based on the above analysis.

TABLE C8-4. Summary of the technical feasibility of GHG control technologies.

Control Technology	Technical Feasibility
1. The use of low carbon containing or lower emitting primary fuels.	Feasible
2. The use of energy efficient processes and technologies, including:	
a. Efficient Simple Cycle CTs	Infeasible / Inferior
b. Reciprocating Internal Combustion Engines (RICE)	Infeasible / Inferior
c. Combined Cycle CTs	Feasible
3. Good combustion and operating practices.	Feasible
4. Carbon Capture and Sequestration (CCS).	Infeasible*

* Carbon capture and sequestration is considered infeasible because no sequestration sites are available within 200 miles of the power plant.

8.7 STEP 3. Rank The Technically Feasible Control Technologies.

Based on the above analysis, simple cycle CTs and RICE electric generating units are not considered technically feasible control technologies for this proposed baseload electric generating capacity. However, for this analysis, these technologies are included in the ranking of the technically feasible options.

With respect to the use of lower emitting primary fuels, simple cycle CTs, combined cycle CTs, and RICE electric generating units may all use the lowest commercially available carbon containing fossil fuel – natural gas. Therefore, the lowest CO_2 and GHG emitting generating technology will be based on the efficiency of the technology and the applicability of the technology to the Project's Purpose and Need.

Table C8-6 includes performance data for the proposed 7HA.02 combined cycle CTs. The lowest design heat rate (i.e., the highest efficiency) for these CTs at 100% load and an ambient temperature of 80 ^oF is 6,830 Btu per kWh of gross electric energy output (Btu/kWh_g). One Btu is equal to 3,413 kWh; therefore, a gross heat rate of 6,830 Btu/kWh_g is equal to an electric generating efficiency of 50% and 799 lb CO_2/MWh_g. Please note that this efficiency is based on the *higher heating value* (HHV) of natural gas. For natural gas, the HHV is 1.109 times the LHV, or approximately 11% higher.

One large natural gas-fired lean burn RICE engine has a design heat rate as low as approximately 8,190 Btu/kWhg based on the HHV of natural gas. This heat rate is equal to an efficiency of approximately 42% (HHV) and a CO_2 emission rate of 947 lb CO_2/MWh_g. The largest natural gas-fired engine currently manufactured has a maximum continuous rating of up to 18.8 MW. However, only one manufacturer currently makes an engine of this size – the Wärtsilä Model 18V50SG. Other manufacturers make smaller natural gas engines of up to approximately 10 MW in size. Therefore, to achieve the same gross electric output, the Project would require at least 40 RICE electric generating units. This would be a far more complex installation and the facility site may not have sufficient space for this many RICE generators.

A high efficiency simple cycle CT has a typical heat rate of approximately 9,160 Btu/kWh, equal to a design efficiency of 37% and a CO_2 emission rate of 1,070 lb CO_2/MWh.

Table C8-5 is a ranking of the technically feasible GHG control technologies based on the above stated ***best case design efficiencies, heat rates, and CO_2 emission rates*** for the RICE and CT electric generating units. From Table C8-5, combined cycle CTs have the highest ranked (lowest emission rate) of the technically feasible control technologies.

TABLE C8-5. Ranking of the technically feasible GHG control technologies for the CTs.

Technology	Best Case (Minimum) Heat Rate Btu/kWh_g	Best Case CO_2 Emission Rate lb/MWh_g
Natural Gas-Fired Combined Cycle CTs	6,830	799
Natural Gas-Fired RICE Engines	8,190	947
Natural Gas-Fired Simple Cycle CTs	9,160	1,070

TABLE C8-6. Performance data for new General Electric Model 7HA.02 combined cycle CTs at various load and ambient air conditions.

PARAMETER	Units	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Ambient Temp.	deg F	20	20	20	20	20	59	59	59	59	59	59	59	80	80	80	80	80	80	80	98.4
Relative Humidity	%	27	27	27	27	27	8	8	8	8	8	8	8	4	4	4	4	4	4	4	2
Load		BASE	BASE	75%	50%	MECL	BASE	BASE	BASE	BASE	75%	50%	MECL	BASE	BASE	BASE	BASE	75%	50%	MECL	BASE
Duct Burner Status		ON	OFF	OFF	OFF	OFF	ON	ON	OFF	OFF	OFF	OFF	OFF	ON	ON	OFF	OFF	OFF	OFF	OFF	ON
Evap. Cooler Status		OFF	OFF	OFF	OFF	OFF	ON	OFF	ON	OFF	OFF	OFF	OFF	ON	OFF	ON	OFF	OFF	OFF	OFF	ON
Comb. Turbine Heat Input	mmBtu/hr	3,709	3,740	1,716	2,254	2,937	3,637	3,697	3,631	3,692	1,646	2,161	2,849	3,513	3,649	3,510	3,646	1,589	2,091	2,750	3,310
Duct Burner Heat Input	mmBtu/hr	1,018					985	975						984	960						1,032
Total Heat Input	**mmBtu/hr**	**4,727**	**3,740**	**1,716**	**2,254**	**2,937**	**4,621**	**4,673**	**3,631**	**3,692**	**1,646**	**2,161**	**2,849**	**4,497**	**4,609**	**3,510**	**3,646**	**1,589**	**2,091**	**2,750**	**4,342**
CT Gross Output	MW(e)	375	375	118	188	282	362	369	362	369	114	181	272	346	363	346	363	108	173	260	322
ST Gross Output	MW(e)	266	163	94	115	135	269	269	169	168	92	112	137	273	273	168	170	91	111	136	267
TOTAL Gross Output	**MW(e)**	**641**	**538**	**211**	**302**	**417**	**632**	**638**	**531**	**537**	**206**	**294**	**409**	**619**	**636**	**514**	**533**	**199**	**284**	**396**	**589**
Gross Heat Rate	Btu/kWh	7,372	6,947	8,124	7,458	7,042	7,318	7,324	6,843	6,875	7,990	7,361	6,965	7,263	7,244	6,831	6,844	7,992	7,354	6,952	7,369
Gross Efficiency	%	46%	49%	42%	46%	48%	47%	47%	50%	50%	43%	46%	49%	47%	47%	50%	50%	43%	46%	49%	46%
Carbon Dioxide (CO_2) Emissions	lb/mmBtu	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98
	lb/hour	552,929	437,491	200,699	263,649	343,502	540,589	546,601	424,698	431,818	192,515	252,744	333,227	526,073	539,129	410,595	426,518	185,858	244,578	321,637	507,856
	lb/MWh(g)	**862**	**813**	**950**	**872**	**824**	**856**	**857**	**801**	**804**	**935**	**861**	**815**	**850**	**847**	**799**	**801**	**935**	**860**	**813**	**862**

PARAMETER	Units	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Ambient Temp.	deg F	98.4	98.4	98.4	98.4	98.4	98.4	115	115	115	115	115	115	115	122	122	122	122	122	122	122
Relative Humidity	%	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Load		BASE	BASE	BASE	75%	50%	MECL	BASE	BASE	BASE	BASE	75%	50%	MECL	BASE	BASE	BASE	BASE	75%	50%	MECL
Duct Burner Status		ON	OFF	OFF	OFF	OFF	OFF	ON	ON	OFF	OFF	OFF	OFF	OFF	ON	ON	OFF	OFF	OFF	OFF	OFF
Evap. Cooler Status		OFF	ON	OFF	OFF	OFF	OFF	ON	OFF	ON	OFF	OFF	OFF	OFF	ON	OFF	ON	OFF	OFF	OFF	OFF
Comb. Turbine Heat Input	mmBtu/hr	3,613	3,307	3,612	1,624	1,992	2,604	2,995	3,597	2,994	3,597	1,613	1,843	2,385	2,838	3,587	2,838	3,587	1,611	1,770	2,282
Duct Burner Heat Input	mmBtu/hr	943						917	935						881	932					
Total Heat Input	**mmBtu/hr**	**4,556**	**3,307**	**3,612**	**1,624**	**1,992**	**2,604**	**3,912**	**4,532**	**2,994**	**3,597**	**1,613**	**1,843**	**2,385**	**3,719**	**4,519**	**2,838**	**3,587**	**1,611**	**1,770**	**2,282**
CT Gross Output	MW(e)	357	322	357	113	161	242	286	355	286	355	113	143	214	267	353	267	353	113	134	200
ST Gross Output	MW(e)	267	157	165	90	104	127	234	256	138	156	85	93	113	220	251	129	153	83	88	107
TOTAL Gross Output	**MW(e)**	**624**	**479**	**522**	**203**	**265**	**368**	**520**	**611**	**424**	**511**	**198**	**236**	**327**	**488**	**604**	**396**	**506**	**196**	**222**	**307**
Gross Heat Rate	Btu/kWh	7,296	6,909	6,915	7,997	7,519	7,070	7,521	7,416	7,063	7,034	8,156	7,806	7,288	7,628	7,484	7,160	7,088	8,236	7,977	7,426
Gross Efficiency	%	47%	49%	49%	43%	45%	48%	45%	46%	48%	49%	42%	44%	47%	45%	46%	48%	48%	41%	43%	46%
Carbon Dioxide (CO_2) Emissions	lb/mmBtu	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98	116.98
	lb/hour	532,950	386,891	422,510	189,947	232,963	304,553	457,615	530,108	350,243	420,766	188,714	215,583	278,983	435,058	528,646	332,000	419,636	188,405	207,048	266,887
	lb/MWh(g)	**853**	**808**	**809**	**935**	**879**	**827**	**880**	**867**	**826**	**823**	**954**	**913**	**853**	**892**	**875**	**838**	**829**	**963**	**933**	**869**

8.8 STEP 4. Evaluate the Most Effective Controls.

From Table C8-5. the highest ranked, lowest emitting CO_2 control technology is the use of efficient natural gas-fired combined cycle CTs. While CCS is not considered technically feasible, this technology is evaluated further below.

8.8.1 Carbon Capture and Sequestration.

As stated above in Step 2, CCS is not a technically feasible control option for these combined cycle CTs. However, even if the severe technical feasibility issues including the lack of an available sequestration site could somehow be resolved, CCS is not an economically feasible control technology for these CTs.

With respect to the performance standards in 40 CFR 60 Subpart TTTTa, the U.S. EPA established a performance standard of 100 lb CO_2/MWh of gross energy output beginning in 2032. While the proposed CTs cannot achieve this standard, there are several Subpart TTTTa compliance options for these CTs other than CCS that could meet these standards, including the use of hydrogen fuel which has zero CO_2 emissions, or limiting the potential electric output of these CTs to less than 40%. When the potential electric output is limited to less than 40%, the applicable limit for *intermediate load combustion turbines* is 1,170 lb CO_2/MWh (gross), based on a 12-month average. From Table C8-6, these CTs can meet that requirement at essentially all operating conditions.

Regarding economic impacts, in its PSD BACT guidance EPA states[14]:

> EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible.

For example, even though the U.S. EPA rejected CCS as a technically infeasible GHG emissions control technology option for the Palmdale Hybrid Power Project, the EPA evaluated the costs of CCS in its Response to Public Comments (October, 2011). (Please note that while EPA approved the permit for this facility, the project was never constructed.) The proposed Palmdale Hybrid Power Project included 520 MW natural gas-fired combined cycle units and 50 MW of solar photovoltaic systems. In the EPA's analysis, the estimated capital costs for the Project were $615 - $715 million ($1.2 to $1.4 million per MW of capacity) , equal to an annualized cost of about $35 million. In comparison, the estimated capital cost for

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[14] U.S. EPA, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases,* (Mar. 2011), page 42.

these two combined cycle CTs would be approximately $1.3 to $1.6 billion. Based on this extremely high capital cost, EPA eliminated CCS as an economically infeasible control option. The EPA's decision to reject CCS based on these very high annual costs was upheld on appeal by the U.S. EPA's Environmental Appeals Board, PSD Appeal No. 11-07, decided September 17, 2012.

The International Energy Agency has estimated the cost of carbon capture and sequestration at $40 to $120 per ton of CO_2 for processes with "dilute" gas streams such as electric power generation. For these combined cycle units, this would be equal to annual costs of $160 to $480 million for these two combined cycle units. These costs would be expected to more than double the cost of electric generation from these units.

In the U.S. EPA's *Documentation for EPA's Power Sector Modeling Platform 2023 Using the Integrated Planning Model 2023 Reference Case,* April 2024, Chapter 6 includes information for CO_2 CCS. Table 6-1 of the Reference Case[15] includes cost and performance information for natural gas combined cycle CTs. For "Vintage 2030" units, the capital costs, expressed in 2022 dollars, is $1,054 per installed kW for combined cycle CTs, and $2,539 per kW for combined cycle with 90% CCS. Based on the EPA's IPM Model, this would be equal to capital costs of $665 million for each combined cycle unit, and $1.6 billion for each combined cycle unit equipped with CCS. That would represent a capital cost *increase* of $934 million for each unit, or a cost increase of 2.4 times the cost without CCS. These costs do not include the costs for transportation of the CO_2 by pipeline, nor does it include the costs for geologic storage. But given that the closest of storage areas are more than 200 miles from the Desert Sun Power Plant site location, the costs for transportation, including a 200 mile pipeline and storage would also be significant.

Please note that this same Table from the EPA report also indicates that the addition of CCS would increase variable O&M costs from $2.10 per MWh to $6.57 per MWh, or by more than 300%. This would significantly impact the cost of electric power produced by these units.

Like the Palmdale Project, the Desert Sun Power Plant location does not have any nearby carbon sequestration sites available. As noted above, the closest of these areas is more than 200 miles from the Desert Sun Power Plant. Therefore, even if the technical feasibility issues for the application of CCS to these combined cycle CTs could be resolved, the use of CCS for this Project would increase the capital cost of the Project by at least 240%, and this cost does not include CO_2 transportation and storage. Based on these findings, CCS is not an economically feasible control technology option for these combined cycle CTs.

[15] Available at https://www.epa.gov/system/files/documents/2024-04/chapter-6-co2-capture-storage-and-transport.pdf.

8.9 STEP 5. Proposed Greenhouse Gas BACT Determination.

Based on this control technology review, the use of efficient, natural gas-fired combined-cycle CTs combined with good combustion and maintenance practices represents BACT for the control of GHG emissions from the proposed combined cycle CTs. Therefore, BACT will be achieved by the CT design and by the proper operation and maintenance of the CTs.

8.9.1 Combustion Turbine Design.

The proposed natural gas-fired General Electric Model 7HA.02 combined cycle CTs are efficient, low CO_2 emitting CTs. The lowest design heat rate (i.e., the highest efficiency) for these CTs at 100% load and an ambient temperature of 80 ^oF is 6,295 Btu per kWh of gross electric energy output (Btu/kWh_g), equal to an electric generating thermal efficiency of 54% and a CO_2 emission rate of 736 lb CO_2/MWh_g..

8.9.2 Emission Limit.

8.9.2.1 Emission Limit Based on the Worst-Case Operation.

The BACT emission limit must be achievable at all times and across all load ranges for which these CTs are designed to operate. To provide flexible power production, these CTs will be designed to meet the BACT emission limits for CO, NO_x, PM, PM_{10}, $PM_{2.5}$, and VOC emissions at the minimum environmental compliant steady state load (MECL) up to the maximum output capability of the CTs.

The CT efficiency decreases and the CO_2 emission rate increases as the load decreases. In addition, the CO_2 emission rate may vary between CTs due to normal variation in the manufacturing process, and even with proper operation and maintenance, the CO_2 emission rate may increase over time due to the normal operation and wear of the CT components. Variation in turbines is expected to be about 3%, and degradation in performance due to normal wear is expected to be an additional 3%[16]. This variation and degradation in performance can result in a 6% increase above the design values in Table C8-6. From Table C8-6, these CTs have a worst-case design CO_2 emission rate of 883 lb/MWh_g at 50% load and an ambient condition of 115 °F. Therefore, this CO_2 emission rate may degrade to 935 lb/MWh_g over time. Furthermore, this rate does not consider startup and shutdown emissions or operation at the MECL when efficiency is even less.

8.9.2.2 Emission Limit Based on the Expected Operation.

The operation of these CTs may vary substantially from day to day. The U.S. EPA Region 9 provided a framework for addressing the variation of turbine efficiency and resulting GHG emission rate as a function of load in their "*Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Pio Pico Energy Center*", November 2012. EPA stated that it is not possible to predict the extent of part-load operation during every year for the life of the generating facility and that facilities are designed to meet a range of operating levels. Therefore, EPA stated it is inappropriate to establish a GHG permit limit that prevents the facility from generating electricity as intended. For the Pio Pico PSD permit, EPA determined that the appropriate methodology for setting the GHG BACT emission limit was to set the

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[16] U.S. EPA Region IX, *Fact Sheet and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit, Pio Pico Energy Center*, PSD Permit Number SD 11-01, June 2012.

final BACT limit at a level achievable during the lowest load, "worst-case" normal operating conditions. This methodology was also used to develop the GHG BACT limit for the APS Ocotillo CTs.

Table C8-7 is a summary of a typical anticipated run time operating scenario for these CTs. The run time scenario includes the heat input for up to 366 startup/shutdown events per year, and a projection of minimum environmental compliance load (MECL), low, mid, and high CT load operation at five (5) ambient temperature conditions. The hours spent at each ambient air temperature condition are based on five years of hourly weather data from the Using National Oceanic and Atmospheric Administration (NOAA) Climate Data Online, (CDO) for the Phoenix weather station. The ambient air temperature ranges were sorted for the ambient air temperature ranges in the table below.

Expected annual operation at each ambient temperature range based on NOAA Climate Data Online data for Phoenix, Arizona.

Temperature Range	Percent of Time	Hours per Year
Less than 40 ^oF	2.07%	181
40 to 60 ^oF.	18.5%	1,624
61 to 80 ^oF	32.5%	2,844
81 to 100 ^oF	35.3%	3,092
101 to 115 ^oF	11.6%	1,014
Greater than 115 ^oF	0.0%	5
TOTAL	**100.0%**	**8,760**

The total operation of each CT was based on 8,760 hours per year of operation, with no more than 2,000 hours per year of duct firing. In addition, operation at each ambient range was distributed approximately equally from 50% load to base load (100% load) operation, with limited operation at MECL load.

From Table C8-7, the annual average CO_2 emission rate for these combined cycle CTs based on this expected operation and including all periods of operation, including startup and shutdown, is 850 pounds of CO_2 per megawatt hour of gross electric output (lb/MWh_g). Note that the analysis in Table C8-7 is based on the design values for a new GE 7HA.02 combined cycle CT and does not represent variation in individual CTs nor does it include the degradation in performance due to normal wear. These variables can result in a 6% increase above the design values. Therefore, based on this analysis, the long-term achievable CO_2 emission rate for these CTs is 890 lb CO_2/MWh_g.

8.9.1 Gas Turbine Maintenance Requirements.

To achieve the proposed BACT emission limits, these CTs must be maintained properly to ensure peak performance of the turbines and ensure that good combustion and operating practices are maintained. Therefore, BACT also includes a requirement to prepare and follow a maintenance plan for each CT. Good CT maintenance practices normally include annual boroscopic inspections of the turbine, generator testing, control system inspections, and periodic fuel sampling and analysis. Good CT maintenance practices also includes major overhauls conducted as recommended by the manufacturer.

TABLE C8-7. Expected operation and CO_2 emission rate for the GE 7HA.02 combined cycle CTs based on the non-degraded design heat rates (2 pages).

Case	Ambient Temp. deg F	Load	Duct Burner Status	Evap. Cooler Status	Heat Input		Heat Rate	Hours	Generation	CO_2 Emissions	
					mmBtu/hr	mmBtu/yr	Btu/kWh	hr/yr	MWh	ton/yr	lb/MWh
Cold Startup						33,120	11,129		2,976	1,937	1,302
Warm/Hot Startup						644,000	11,572		55,650	37,666	1,354
1	**20**	BASE	ON	OFF	4,727	236,343	7,372	50	32,061	13,823	862
2		BASE	OFF	OFF	3,740	187,000	6,947	50	26,919	10,937	813
3		75%	OFF	OFF	1,716	68,629	8,124	40	8,448	4,014	950
4		50%	OFF	OFF	2,254	90,155	7,458	40	12,088	5,273	872
5		MECL	OFF	OFF	2,937	0	7,042	0	0	0	
6	**59**	BASE	ON	ON	4,621	924,273	7,318	200	126,300	54,059	856
7		BASE	ON	OFF	4,673	934,551	7,324	200	127,609	54,660	857
8		BASE	OFF	ON	3,631	1,089,191	6,843	300	159,159	63,705	801
9		BASE	OFF	OFF	3,692	1,107,453	6,875	300	161,095	64,773	804
10		75%	OFF	OFF	1,646	493,729	7,990	300	61,791	28,877	935
11		50%	OFF	OFF	2,161	648,195	7,361	300	88,054	37,912	861
12		MECL	OFF	OFF	2,849	68,368	6,965	24	9,816	3,999	815
13	**80**	BASE	ON	ON	4,497	1,461,614	7,263	325	201,244	85,487	850
14		BASE	ON	OFF	4,609	1,474,842	7,244	320	203,587	86,261	847
15		BASE	OFF	ON	3,510	1,930,540	6,831	550	282,634	112,914	799
16		BASE	OFF	OFF	3,646	2,005,407	6,844	550	293,002	117,292	801
17		75%	OFF	OFF	1,589	873,872	7,992	550	109,345	51,111	935
18		50%	OFF	OFF	2,091	1,045,419	7,354	500	142,155	61,145	860
19		MECL	OFF	OFF	2,750	134,730	6,952	49	19,381	7,880	813

TABLE C8-7. Expected operation and CO_2 emission rate for the GE 7HA.02 combined cycle CTs based on the non-degraded design heat rates (2 pages).

Case	Ambient Temp. deg F	Load	Duct Burner Status	Evap. Cooler Status	Heat Input		Heat Rate	Hours	Generation	CO_2 Emissions	
					mmBtu/hr	mmBtu/yr	Btu/kWh	hr/yr	MWh	ton/yr	lb/MWh
20	98	BASE	ON	ON	4,342	1,519,538	7,369	350	206,211	88,875	862
21		BASE	ON	OFF	4,556	1,594,621	7,296	350	218,573	93,266	853
22		BASE	OFF	ON	3,307	1,901,778	6,909	575	275,267	111,231	808
23		BASE	OFF	OFF	3,612	2,076,860	6,915	575	300,320	121,471	809
24		75%	OFF	OFF	1,624	933,689	7,997	575	116,761	54,610	935
25		50%	OFF	OFF	1,992	1,145,139	7,519	575	152,308	66,977	879
26		MECL	OFF	OFF	2,604	239,526	7,070	92	33,878	14,009	827
27	115	BASE	ON	ON	3,912	391,204	7,521	100	52,012	22,881	880
28		BASE	ON	OFF	4,532	453,177	7,416	100	61,112	26,505	867
29		BASE	OFF	ON	2,994	598,828	7,063	200	84,789	35,024	826
30		BASE	OFF	OFF	3,597	719,405	7,034	200	102,276	42,077	823
31		75%	OFF	OFF	1,613	322,654	8,156	200	39,561	18,871	954
32		50%	OFF	OFF	1,843	368,593	7,806	200	47,217	21,558	913
33		MECL	OFF	OFF	2,385	33,389	7,288	14	4,581	1,953	853
34	122	BASE	ON	ON	3,719	22,315	7,628	6	2,925	1,305	892
35		BASE	ON	OFF	4,519	0	7,484		0	0	
36		BASE	OFF	ON	2,838	0	7,160		0	0	
37		BASE	OFF	OFF	3,587	0	7,088		0	0	
38		75%	OFF	OFF	1,611	0	8,236		0	0	
39		50%	OFF	OFF	1,770	0	7,977		0	0	
40		MECL	OFF	OFF	2,282	0	7,426		0	0	
TOTAL						**27,772,150**	**7,268**	**8,760**	**3,821,106**	**1,624,339**	**850**

8.9.2 Averaging Period for the Emission Limit.

Because the GHG emission rate varies with ambient air temperatures, and because the operating load will vary not only with the time of day but also the time of year, the averaging period for the GHG BACT limit must be long enough to encompass this variability in operation. A 12-month rolling average basis is consistent with the majority of the CO_2 BACT emission limits and is also consistent with the final CO_2 emission standard under 40 CFR 60 Subpart TTTTa. In the preamble to the proposed Subpart TTTT, EPA stated[17] "This 12-operating-month period is important due the inherent variability in power plant GHG emissions rates." EPA went on to say, "a 12-operating month rolling average explicitly accounts for variable operating conditions, allows for a more protective standard and decreased compliance burden, allows EGUs to have and use a consistent basis for calculating compliance (i.e., ensuring that 12 operating months of data would be used to calculate compliance irrespective of the number of long-term outages), and simplifies compliance for state permitting authorities". EPA Region 9 also stated in the Pio Pico response to comments that "EPA believes that annual averaging periods are appropriate for GHG limits in PSD permits because climate change occurs over a period of decades or longer, and because such averaging periods allow facilities some degree of flexibility while still being practically enforceable". For these reasons, the operational limit should be based on a 12-month rolling average.

8.9.3 Proposed GHG BACT Requirements.

Based on this analysis, APS has concluded that the use of efficient combined cycle combustion turbines and the use of good combustion practices in combination with low carbon containing fuels including natural gas and hydrogen represents the best available control technology (BACT) for the control of GHG emissions from the proposed GE 7HA.02 combined-cycle CTs.

Based on the above analysis, we have concluded that BACT for the control of GHG emissions from the proposed GE 7HA.02 combined-cycle CTs is an emission rate of 890 lb CO_2 per MWh of gross electric output for all periods of operation, including periods of startup and shutdown, based on a 12-operating month rolling average. However, this evaluated limit is greater than the currently applicable standard for base load combustion turbines in 40 CFR 60 Subpart TTTTa of 800 lb CO_2/MWh. Because BACT cannot be less stringent than an applicable performance standard, APS will propose the emission standard from Subpart TTTTa for base load combustion turbines as BACT. ***However, if Subpart TTTTa is repealed, APS proposes the evaluated CO_2 emission standard of 890 lb/MWh (gross) as BACT.*** Therefore, APS proposes the following limits as BACT for the control of GHG emissions from these new CTs:

1. CO_2 emissions may not exceed 800 lb CO_2 per MWh of gross electric output for all periods of operation, including periods of startup and shutdown, based on a 12-operating month rolling average.
2. The permittee shall prepare and follow a Maintenance Plan for each CT.

[17] Federal Register, Vol. 79, No. 5, January 8, 2014, page 1,481.

Appendix D.

Control Technology Review for the Balance of Plant Equipment.

Desert Sun Power Plant

Construction and Title V Air Quality Operating Permit Application

Appendix D: Control Technology Review for the Balance of Plant Equipment.

May 2026

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Chapter 1. Executive Summary.

The Prevention of Significant Deterioration of Air Quality (PSD) program in the Code of Federal Regulations, 40 CFR §52.21 and County Rule 240, Section 305 requires that a new major stationary source within an attainment area must undergo PSD review and obtain a construction permit prior to commencing construction. The Desert Sun Power Plant will be subject to PSD review and will require the application of the Best Available Control Technology (BACT) for the control of carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM), PM_{10}, $PM_{2.5}$, volatile organic compounds (VOC), and greenhouse gas (GHG) emissions. This document is a control technology review or BACT analysis for the auxiliary boiler, natural gas heater, cooling towers, fire pump, natural gas piping systems and SF_6 insulated electrical equipment.

Proposed BACT emission limits for the natural gas-fired auxiliary boiler.

Pollutant	BACT Emission Limit
Carbon Monoxide (CO)	0.04 lb/mmBtu based on a 3-hour average
Nitrogen Oxides (NO_x)	0.037 lb/mmBtu based on a 3-hour average
Particulate Matter (PM, $PM_{10,}$ and $PM_{2.5}$)	The auxiliary boiler may only use natural gas as a fuel. 0.005 lb/mmBtu based on a 3-hour average
Volatile Organic Compounds (VOC)	0.0055 lb/mmBtu based on a 3-hour average
Greenhouse Gas (GHG) Emissions	120 pounds of CO_2 per million Btu of heat input. The auxiliary boiler may only use natural gas as a fuel.

Proposed BACT emission limits for the natural gas-fired natural gas heater.

Pollutant	BACT Emission Limit
Carbon Monoxide (CO)	0.04 lb/mmBtu based on a 3-hour average
Nitrogen Oxides (NO_x)	0.011 lb/mmBtu based on a 3-hour average
Particulate Matter (PM, $PM_{10,}$ and $PM_{2.5}$)	The natural gas heater may only use natural gas as a fuel. 0.005 lb/mmBtu based on a 3-hour average
Volatile Organic Compounds (VOC)	0.0055 lb/mmBtu based on a 3-hour average
Greenhouse Gas (GHG) Emissions	120 pounds of CO_2 per million Btu of heat input. The natural gas heater may only use natural gas as a fuel.

Proposed BACT emission limits for the forced draft cooling towers.

Pollutant	BACT Emission Limit
Particulate Matter (PM, PM_{10}, and $PM_{2.5}$)	Emissions from each cooling tower shall be controlled by utilizing high efficiency drift eliminators with a maximum design drift loss of no more than 0.0005% of the circulating water flowrate

Proposed BACT emission limits for the diesel engine-driven emergency fire pump.

Pollutant	BACT Emission Limit
Carbon Monoxide (CO)	1. The diesel engine-driven emergency fire pump shall comply with the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* 40 CFR 60, Subpart IIII. 2. The total operation of the fire pump may not exceed 200 hours per year.
Nitrogen Oxides (NO_x)	
Particulate Matter (PM, PM_{10}, and $PM_{2.5}$)	
Volatile Organic Compounds (VOC)	
Greenhouse Gas (GHG) Emissions	

Proposed BACT emission limits for the natural gas piping systems.

Pollutant	BACT Emission Limit
Greenhouse Gas (GHG) Emissions	1. The permittee shall implement an auditory / visual / olfactory (AVO) monitoring program for detecting leaks in the natural gas piping components. 2. AVO monitoring shall be performed in accordance with a written monitoring program.

Proposed BACT emission limits for the SF_6 insulated electrical equipment.

Pollutant	BACT Emission Limit
Greenhouse Gas (GHG) Emissions	1. The Permittee shall install, operate, and maintain enclosed-pressure SF_6 circuit breakers with a maximum design annual leakage rate of 0.5% by weight. 2. The new circuit breakers shall be equipped with a leak detection system. 3. The permittee shall maintain records of the date that any leak is detected in a circuit breaker and the leak amount in weight percent. 4. The permittee shall maintain records of the date and the amount of SF_6 added to the circuit breakers.

Chapter 2. Control Technology Review Methodology.

2.1 Best Available Control Technology (BACT).

The Clean Air Act defines "best available control technology" (BACT) as:

> "…an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act. Emissions from any source utilizing clean fuels, or any other means, to comply with this paragraph shall not be allowed to increase above levels that would have been required under this paragraph as it existed prior to November 15, 1990."

Under the Maricopa County Air Pollution Control Regulations, Rule 100, Section 200.25, "best available control technology" (BACT) means:

200.25 BEST AVAILABLE CONTROL TECHNOLOGY (BACT): An emissions limitation, based on the maximum degree of reduction for each pollutant, subject to regulation under the Act, which would be emitted from any proposed stationary source or modification, which the Control Officer, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combination techniques for control of such pollutant. Under no circumstances shall BACT be determined to be less stringent than the emission control required by an applicable provision of these rules or of any State or Federal laws ("Federal laws" include the EPA approved State Implementation Plan (SIP)). If the Control Officer determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

The BACT requirement applies for a given pollutant to each individual new or modified emission unit when the project, on a facility-wide basis, has a significant net emissions increase for that pollutant. Individual BACT determinations are performed on a unit-by-unit, pollutant-by-pollutant basis.

2.2 Top Down BACT Methodology.

The United States Environmental Protection Agency (U.S. EPA) recommends a “top-down” approach in conducting a BACT or Lowest Available Emission Rate (LAER) analysis. This method evaluates progressively less stringent control technologies until a level of control considered BACT is reached, based on the environmental, energy, and economic impacts. The five steps of a top-down BACT analysis are:

1. Identify all available control technologies with practical potential for application to the emission unit and regulated pollutant under evaluation;
2. Eliminate all technically infeasible control technologies;
3. Rank remaining control technologies by effectiveness and tabulate a control hierarchy;
4. Evaluate most effective controls and document results; and
5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

The impact analysis of any BACT review includes an evaluation of environmental, energy, technical, and economic impacts. The net environmental impact associated with a control alternative may be considered if dispersion modeling analyses are performed. The energy impact analysis estimates the direct energy impacts of the control alternatives in units of energy consumption. If possible, the energy requirements for each control option are assessed in terms of total annual energy consumption. The economic impact of a control option is assessed in terms of cost effectiveness and ultimately, whether the option is economically reasonable. The economic impacts are reviewed on a cost per ton controlled basis, as directed by the U.S. EPA’s Office of Air Quality Planning and Standards (OAQPS) Cost Control Manual, Fifth Edition.

The EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which EPA believes must be met by any BACT determination, irrespective of whether it is conducted in a “top-down” manner. First, the BACT analysis must include consideration of the most stringent available technologies: i.e., those that provide the “maximum degree of emissions reduction.” Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of “energy, environmental, and economic impacts” contained in the record of the permit decisions.

2.3 Technical Feasibility.

Step 2 of the BACT analysis involves the evaluation of all of the identified available control technologies from Step 1 to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar emission source, or there is technical agreement that the technology can be applied to the emission source. Technical infeasibility is demonstrated through clear physical, chemical, or other engineering principles that demonstrate that technical difficulties preclude the successful use of the control option.

The technology must be commercially available for it to be considered as a candidate for BACT. EPA’s New Source Review Workshop Manual, page B.12 states, “Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."

In general, if a control technology has been "demonstrated" successfully for the type of emission source under review, then it would normally be considered technically feasible. For an undemonstrated technology, "availability" and "applicability" determine technical feasibility. Page B.17 of the New Source Review Workshop Manual states:

> Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.
>
> Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:
>
> - concept stage;
> - research and patenting;
> - bench scale or laboratory testing;
> - pilot scale testing;
> - licensing and commercial demonstration; and
> - commercial sales.

Applicability involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission source), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission source may not be applicable to a similar source depending on differences in gas stream characteristics.

2.4 Economic Feasibility.

Economic feasibility is normally evaluated according to the average and incremental cost effectiveness of the control option. From the U.S. EPA's New Source Review Manual, page B.31, average cost effectiveness is the dollars per ton of pollutant reduced. The incremental cost effectiveness is the cost per ton reduced from the technology being evaluated as compared to the next lower technology. The EPA NSR Review Manual states that, "where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if any, between the application of the control technology on those sources and the particular source under review".

In addition to the average and incremental cost effectiveness analysis, EPA has also used direct comparisons of control technology costs to overall project costs as part of recent GHG BACT determinations. Regarding economic impacts, in its PSD GHG BACT guidance EPA states[1]:

[1] EPA, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases*, (Mar. 2011), page 42.

> EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated in Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible.

The U.S. EPA evaluated the costs of CCS in its Response to Public Comments (October, 2011) for the Palmdale Hybrid Power Project, a 570 MW power plant based on approximately 520 MW of natural gas-fired combined cycle units and 50 MW of solar photovoltaic systems. In the EPA's analysis, the estimated capital costs for the Project are $615-$715 million, equal to an annualized cost of about $35 million over the 20-year lifetime of the facility. In comparison, the estimated annual cost for CCS for this Project is about $78 million, ***or more than twice the value of the facility's annual capital costs***. Based on these very high costs, EPA eliminated CCS as an economically infeasible control option. The EPA's decision to reject CCS based on these very high annual costs was upheld on appeal by the U.S. EPA's Environmental Appeals Board (EAB), PSD Appeal No. 11 -07, decided September 17, 2012.

The EAB also rejected a challenge to a PSD permit for the construction of a new ethylene production unit in Baytown, Texas. The EAB upheld the determination that the installation of CCS was too expensive, on a total cost basis, to be selected as BACT for limiting GHG emissions from the proposed unit.

2.4.1 Average Cost Effectiveness.

In the EPA's New Source Review Manual, page B.37, average cost effectiveness is calculated as:

$$\text{Average Cost Effectiveness (\$ per ton removed)} = \frac{\text{Control option annualized cost}}{\text{Baseline emission rate} - \text{Control option emissions rate}}$$

The average cost effectiveness is based on the overall reduction in the air pollutant from the baseline emission rate. In the draft Workshop Manual, the EPA states that the baseline emission rate represents uncontrolled emissions for the source. However, the manual also states that when calculating the cost effectiveness of adding controls to inherently lower emitting processes, baseline emissions may be assumed to be the emissions from the lower emitting process itself.

2.4.2 Incremental Cost Effectiveness.

In addition to determining the average cost effectiveness of a control option, the U.S. EPA's New Source Review Manual states that the incremental cost effectiveness between dominant control options should also be calculated. The incremental cost effectiveness compares the costs and emissions performance level of a control option to those of the next most stringent control option:

$$\text{Incremental Cost (\$ per incremental ton removed)} = \frac{\text{Control option annualized cost} - \text{Next control option annualized cost}}{\text{Next control option emission rate} - \text{Control option emissions rate}}$$

2.5 Alternative to Top-Down BACT Analysis

In the Maricopa County Air Quality Permitting Handbook, August 2023, MCAQD states that to streamline the BACT selection process, MCAQD will accept BACT for the same or similar source category as listed by the South Coast Air Quality Management District (SCAQMD), San Joaquin Valley Air Pollution Control District (SJVAPCD), the Bay Area Air Quality Management District (BAAQMD), or another regulatory agency accepted by MCAQD as a viable alternative.

If an owner or operator of a source opts to select control technology for the same or similar source category accepted by the air quality management districts in California, the owner or operator may forego conducting the top-down BACT analysis.

2.6 Scope of the Control Technology Review.

The U.S. EPA has a longstanding policy regarding the scope of control technology options which the review agency may consider in a control technology review or BACT analysis. The scope of potential options relates directly to a proposed project's basic purpose or design. In short, the list of options should not include processes or options that would fundamentally redefine the source proposed by the applicant.

In the U.S. EPA EAB decision on the Prairie State Generating Station, PSD Appeal No. 05-05, the EAB explained (pages 27-28) that the facility's "basic purpose" or basic design," as defined by the applicant, is the fundamental touchstone of EPA's policy on "redefining the source":

> …Congress intended the permit applicant to have the prerogative to define certain aspects of the proposed facility that may not be redesigned through application of BACT and that other aspects must remain open to redesign through the application of BACT. The parties' arguments, properly framed in light of their agreement on this central proposition, thus concern the proper demarcation between those aspects of a proposed facility that are subject to modification through the application of BACT and those that are not.
>
> We see no fundamental conflict in looking to a facility's basic "purpose" or to its "basic design" in determining the proper scope of BACT review, nor do we believe that either approach is at odds with past Board precedent.

This EAB decision was upheld by the United States Court of Appeals, 7th Circuit.[2]

When EPA issued guidance in 2011 for conducting control technology reviews for greenhouse gas (GHG) emissions, EPA confirmed that a BACT analysis should not redefine the source's purpose:[3]

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[2] *Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007).

[3] U.S. EPA, EPA-457/B-11-001, *PSD and Title V Permitting Guidance for Greenhouse Gases* 26 (Mar. 2011) (citing *Prairie State*, 13 E.A.D. at 23).

> While Step 1 [of a BACT process] is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include lower pollution processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.

The EAB has analyzed the redefinition of the source concept in the context of a past permitting proceeding similar to the proposed Project. In their challenges to a PSD permit issued for the Pio Pico Energy Center, petitioners asserted before the EAB that EPA had erred in eliminating combined-cycle gas turbines in Step 2 of its BACT analysis for GHG emissions. Like the proposed project, Pio Pico is a simple cycle gas-fired facility designed to back up renewable generation by providing peaking and load-shaping capability. As the EAB recognized in its Pio Pico decision and consistent with EPA guidance, a permitting authority can consider peaking facilities, intermediate load facilities and base load facilities to be different electricity generation source types. The EAB explained how "plants operating in 'peaking mode' typically remain idle much of the time but can be started up when power demand increases … and, unlike base load plants, typically use simple-cycle rather than combined-cycle units as well as smaller turbines."[4]

The U.S. EPA has also addressed the issue of whether a peaking facility must consider energy storage such as batteries in the control technology review. In the U.S. EPA's Environmental Appeals Board (EAB) decision for the APS Ocotillo Power Plant[5], the EAB stated that "Maricopa County did not abuse its discretion when it determined that pairing energy storage at this facility would "redefine the source", making the following statements and conclusions.

> But Step 1's broad look is "not without limits." *Id*. Consideration of fundamentally different facility types than those proposed by permit applicants generally is not required. Indeed, EPA guidance and Board precedent, affirmed by the U.S. Court of Appeals for the Seventh Circuit, give permitting authorities the discretion to exclude a proposed control alternative from consideration in the BACT analysis, if that proposed alternative would "redefine the design of the source."

The EAB went on to state (page 336):

> As explained in *La Paloma*, to determine whether an emissions control option would fundamentally redefine a proposed source, permit issuers should begin by examining how the permit applicant defines the proposed facility's "end, object, aim, or purpose," i.e., its "basic design." That "basic design" typically is set forth in the permit application and supporting materials in the administrative record. *Id*. at 286; *accord Palmdale*, 15 E.A.D. at 731; *Desert Rock*, 14 E.A.D. at 530; *Prairie State*, 13 E.A.D. at 21-23. The permit issuer should then take a "hard look" at the applicant's "basic design," identifying design elements that are "inherent" to the applicant's purpose and design elements that possibly could be altered to achieve pollutant emissions reductions without disrupting that purpose.

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[4] *In re Pio Pico Energy Center*, PSD Appeal Nos. 12-04 through 12-06, slip op. at 63 (EAB Aug. 2, 2013).

[5] In Arizona Public Services Company, PSD Appeal No. 16-01, Order Denying Review, September 1, 2016 page 328.

The EAB concluded this issue by stating:

> The administrative record in this case supports Maricopa County's conclusion that integrating energy storage into the Ocotillo project would interfere with Arizona Public Service's ability to meet its customers' needs for "rapid, reliable power," as that option likely would not allow Arizona Public Service to meet "short peak demand[s]," "several short peak demands in a row," or "extended peak demand[s]" on an "immediate basis." *See* RTC at 8-9. For example, Sierra Club concedes on appeal that the paired energy storage option it advocates would not allow Arizona Public Service to fire the turbines to maximum capacity in 2 minutes. Pet. at 16 & n.12. As such, the option would not fulfill Arizona Public Service's project purpose. Maricopa County reasonably determined that energy storage would not be adequate to stabilize the electrical grid, as necessary in a situation with a large and growing proportion of intermittent power sources such as solar and wind. *See* RTC at 11-12. The record supports a determination that these aspects of the facility's design are inherent ones, central to Arizona Public Service's business purpose in proposing the Ocotillo Modernization Project, and Maricopa County appropriately identified them as such. *Id*. at 8-9, 11-12.

In the U.S. EPA's Response to Comments on the Red Gate PSD Permit for GHG Emissions, PSD-TX-1322-GHG, February 2015,[6] issued for a peaking facility to be comprised of reciprocating internal combustion engines (RICE), EPA determined that "energy storage cannot be required in the Step 1 BACT analysis as a matter of law." *Id.* at 1 (explaining that "'incorporating energy storage' in Step 1 of the BACT analysis for a [RICE] resource would constitute the consideration of an alternative means of power production in violation of long-established principles for what can occur in Step 1 of the BACT analysis") (citing *Sierra Club v. EPA*, 499 F.3d 653, 655 (7th Cir. 2007)). EPA concluded that energy storage, either "to replace all or part of the proposed . . . project," would fundamentally redefine the source. *Id.* at 2.

Like this Project, the purpose of the Red Gate project was to provide reliable, rapidly dispatchable power to support renewables and the transmission grid. Because "energy storage first requires separate generation and the transfer of the energy to storage to be effective . . . [it] is a fundamentally different design than a RICE resource that does not depend upon any other generation source to put energy on the grid." *Id.* Energy storage could not meet that production purpose for the duration or scale needed. *Id.* at 2-3. As EPA correctly observed, "[t]he nature of energy storage and the requirement to replenish that storage with another resource goes against the fundamental purpose of the facility." *Id.* at 3.

Similarly, in another PSD permit for a peaking facility for the Shady Hills Generating Station (Jan 2014), this time with natural gas-fired simple cycle units, EPA also concluded that energy storage would not meet the purpose of the facility and therefore should not be considered in the BACT analysis.[7]

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[6] *Response to Public Comments* for the South Texas Electric Cooperative, Inc. – Red Gate Power Plant PSD Permit for Greenhouse Gas Emissions, PSD-TX-1322-GHG (Nov. 2014), http://www.epa.gov/region6/6pd/air/pd-r/ghg/stec-redgate-resp2sierra-club.pdfNov%2014 .

[7] Responses to Public Comments, Draft Greenhouse Gas PSD Air Permit for the Shady Hills Generating Station at 10-11 (Jan 2014), http://www.epa.gov/region04/air/permits/ghgpermits/shadyhills/ShadyHillsRTC%20_011314.pdf.

Chapter 3. Auxiliary Boiler Control Technology Review.

The Desert Sun Power Plant will include one (1) natural gas-fired auxiliary boiler which can be used to provide steam to preheat the heat recovery steam generators (HRSG) and the steam turbines on each combined cycle unit. This boiler will fire only natural gas and will have a maximum design heat input capacity of 90 mmBtu per hour. Potential emissions for the auxiliary boiler based on the heat input limit and the proposed BACT emission limits in this application are included in Table D3-1.

TABLE D3-1. Potential emissions for the auxiliary boiler.

Pollutant		Emission Factor		Heat Input Rate		Potential to Emit	
		lb/mmcf	lb/mmBtu	mmBtu/hr	mmBtu/yr	lb/hr	ton/year
Carbon Monoxide	CO	40.0	0.040	90	90,000	3.60	1.80
Nitrogen Oxides	NO_x	37.0	0.037	90	90,000	3.33	1.67
Particulate Matter	PM	7.6	0.0076	90	90,000	0.68	0.34
Particulate Matter	PM_{10}	5.0	0.005	90	90,000	0.45	0.23
Particulate Matter	$PM_{2.5}$	5.0	0.005	90	90,000	0.45	0.23
Sulfur Dioxide	SO_2	0.6	0.0006	90	90,000	0.05	0.03
Vol. Org. Cmpds	VOC	5.5	0.0055	90	90,000	0.50	0.25
Sulfuric Acid Mist	H_2SO_4		0.00006	90	90,000	0.005	0.003
Fluorides (as HF)	HF			90	90,000	0.000000	0.00
Lead	Pb	0.0005	0.0000005	90	90,000	0.000045	0.00002
Carbon Dioxide	CO_2	116,976	117.0	90	90,000	10,527.8	5,263.9
Greenhouse Gases	CO_2e	117,096	117.1	90	90,000	10,538.7	5,269.3

Footnotes

1. Potential annual emissions are based on an annual heat input limit of 90,000 mmBtu per year.
2. CO and NO_x emissions are based on concentrations of 50 and 30 ppmdv at 3% O_2, respectively.
3. Emission factors for uncontrolled PM, SO_2, and lead (Pb) emissions are for uncontrolled natural gas-fired boilers from the U.S. EPA document *AP-42, Compilation of Air Pollutant Emission Factors,* 5th Edition, section 1.4, Table 1.4-1. The emission rate in pounds per million cubic feet of gas (lb/mmcf) was converted to pounds per million Btu based on a natural gas heat content of 1,000 mmBtu per mmcf.
4. Emission factors for uncontrolled PM_{10} and $PM_{2.5}$ are from the boiler manufacturer.
5. Sulfuric acid mist emissions are based on 10% conversion of SO_2 to SO_3.
6. Natural gas does not contain significant amounts of fluorine. Therefore, fluoride emissions are expected to be insignificant.
7. Greenhouse gas (GHG) emissions are based on the emission factors for CO_2, N_2O and CH_4 are from 40 CFR 98, Tables C-1 and C-2. The CO_2e factors are from 40 CFR 98, Subpart A, Table A-1.

3.1 Carbon Monoxide (CO) Control Technology Review.

Carbon monoxide (CO) is emitted from natural gas-fired boilers as a result of incomplete combustion. Therefore, the most direct approach for reducing CO emissions and also reduce the other related pollutants is to improve combustion. Incomplete combustion also leads to emissions of volatile organic compounds (VOC) and organic hazardous air pollutants (HAP) such as formaldehyde. CO emissions as well as VOC and organic HAP emissions may also be reduced using post combustion air quality control systems.

3.1.1 BACT Baseline.

There are no applicable New Source Performance Standards (NSPS) or local air pollution control requirements for CO emissions from this boiler.

3.1.2 STEP 1. Identify All Available Control Technologies.

Table D3-2 is a summary of CO emission limits for natural gas-fired auxiliary boilers from the U.S. EPA's RACT/BACT/LAER, the South Coast Air Quality Management District's (SCAQMD) BACT guidelines database, and from recently issued permits.

TABLE D3-2. CO BACT limits for natural gas-fired boilers.

Facility	State	Permit Date	Heat Input, mmBtu/hr	Limit, lb/mmBtu	Averaging Period	Control Systems
Maple Creek Energy, LLC	IN	2023	96	0.037	3-hour	GCP
Mountain State Clean Energy LLC	WV	2022	80	0.039	3-hour	GCP
Nemadji Trail Energy Center	WI	2020	100	0.0037	3-hour	GCP + OC
Virginia Electric and Power Company	VA	2019	88	0.037	3-hour	GCP
AES Huntington Beach	CA	2006	2,088	0.0037	1-hour	OC

Footnotes

GCP means good combustion practices; OC means oxidation catalyst system.

Based on these recent decisions and a review of current CO control technologies, the available control options for CO (and VOC) emissions from natural gas-fired boilers include the use of good combustion practices and the use of oxidation catalysts as post combustion control systems. Good combustion practices includes standard burners and low NO_x burners.

3.1.3 STEP 2. Identify Technically Feasible Control Technologies.

Each of the available control options identified above including good combustion practices and oxidation catalyst systems are technically feasible CO control technologies for the proposed auxiliary boiler.

3.1.4 STEP 3. Rank the Technically Feasible Control Technologies.

The highest level of control and lowest emission rate from the auxiliary boiler is the use of good combustion practices in combination with an oxidation catalyst system. From Table D3-2, the lowest permitted emission limits of 0.00037 lb/mmBtu is equal to a CO concentration of 5 parts per million on a dry volume basis corrected to 3% excess oxygen (ppmdv at 3% O_2). And from Table D3-2, the other boilers are permitted at a CO emission rate of 0.037 lb/mmBtu, equal to a CO concentration of 50 ppmdv at 3% O_2. Therefore, the lowest BACT limits in Table D4-2 are based on oxidation catalyst control efficiencies of 90%.

3.1.5 STEP 4. Evaluate the Most Effective Controls.

The use of an oxidation catalyst system will reduce CO emissions from 50 ppmdv to 5 ppmdv, or a total reduction of 1.6 tons per year, from 1.8 tons per year to 0.2 tons per year.

However, an oxidation catalyst control system would have a significant cost. Table D3-3 is a summary of the estimated equipment costs for an oxidation catalyst system. From Table D3-3, an oxidation catalyst system would have a purchased equipment cost of $518,000 in 2026 dollars. Based on a 7% interest rate and a project life of 20 years, the capital recovery factor for this investment is 0.0944. Therefore, the annual cost to pay for the capital investment is $48,900 per year. For a CO reduction of 1.6 tons per year, the cost effectiveness of an oxidation catalyst control system based on ONLY the capital investment would be:

$$\text{Average Cost Effectiveness (\$ per ton removed)} = \frac{\text{Control option annualized cost}}{\text{Baseline emission rate – Control option emissions rate}}$$

$$\text{Average Cost Effectiveness (\$ per ton removed)} = \frac{\$48{,}900}{1.6 \text{ tons}} = \$30{,}600 \text{ per ton of CO reduced}$$

This is a very high control cost for the use of oxidation catalysts to control CO emissions, especially since this cost is based only on the capital investment cost, and does not include other operating and maintenance (O&M) costs such as increased fan electric power requirements and the periodic replacement of the catalyst. Based on these high costs, an oxidation catalyst control system is not an economically feasible control technology for these boilers. The South Coast Air Quality Management District's BACT maximum cost effectiveness value for CO emissions in 2025 was $867 per ton of average cost effectiveness, and $2,493 for the incremental cost effectiveness. The control cost effectiveness of an oxidation catalyst for this boiler would be much more than these values. Therefore, an oxidation catalyst system is not an economically feasible CO control technology for this auxiliary boiler.

TABLE D3-3. Estimated equipment costs for an oxidation catalyst system for one boiler.

Item		Cost
Catalyst Cost		$ 141,000
Housing Cost	25% of Catalyst Cost	$ 35,300
Instrumentation	10% of Catalyst Cost	$ 14,100
Subtotal, Direct Equipment Cost		$ 190,400
Installation	25% of Direct Equipment Cost	$ 47,600
Sales Tax	5.5% of Direct Equipment Cost	$ 10,500
Freight	5% of Direct Equipment Cost	$ 9,500
Contingency	10% of Direct Equipment Cost	$ 19,000
TOTAL EQUIPMENT COST (1998 Dollars)		$ 277,000
TOTAL EQUIPMENT COST (2026 Dollars)		**$ 518,000**
Capital Recovery Factor		0.0944
Annual Capital Cost		$ 48,900
CO Emission Reduction, ton/yr		4.26
Average Cost Effectiveness, $ per ton		**$ 11,500**

Footnotes

1. The catalyst costs are based on an analysis of oxidation catalyst system costs from Engelhard from the report *Cost-Effectiveness of Oxidation Catalyst Control of Hazardous Air Pollutant (HAP) Emissions from Stationary Combustion Turbines*, prepared by the Combustion Turbine Work Group of the Industrial Combustion Coordinated Rulemaking (ICCR), September, 1998. The regression analysis is based on the flue gas flowrate in pounds per second ranging from 28.4 to 984.0 lb/sec, and is given by the equation:

$$\text{Catalyst Cost}, \$ = \$1{,}541.8 \times \frac{\text{lb flue gas}}{\text{second}} + \$102{,}370 = \$285{,}000$$

The flue gas flow for this boiler is 24.9 lb/sec.

3.1.6 STEP 5. Proposed Carbon Monoxide (CO) BACT Determination.

Based on this analysis, APS has concluded that the use of good combustion practices including the use of ultra-low NO_x burners represents the best available control technology (BACT) for the control of CO emissions from the proposed auxiliary boiler. APS proposes the following as BACT for CO emissions from this boiler:

1. Carbon monoxide (CO) emissions may not exceed 0.04 lb/mmBtu based on a 3-hour average.

3.2 Nitrogen Oxides (NO_x) Control Technology Review.

Nitrogen oxides (NO_x) consist of both nitrogen oxide (NO), and nitrogen dioxide (NO_2). During combustion, NO usually accounts for about 90% of the total NO_x emissions. However, since NO is converted to NO_2 in the atmosphere, the mass emission rate of NO_x is usually reported as NO_2.

NO_x is formed during combustion by two major mechanisms; thermal formation (Thermal NO_x), and fuel formation (Fuel NO_x). Thermal NO_x results from the high temperature oxidation of nitrogen (N_2) and oxygen (O_2). In this mechanism, N_2 is supplied from air, which is 78% N_2 by volume. Thermal NO_x formation increases exponentially with temperature, becoming significant at temperatures above 2,800 °F. Fuel NO_x results from the oxidation of organic nitrogen compounds in the fuel. Because fuel bound nitrogen is more easily converted to NO_x during combustion, nitrogen levels in fuel have a significant impact on NO_x formation. However, since natural gas has only trace organic nitrogen compounds, thermal NO_x is the primary source of NO_x emissions from natural gas-fired boilers.

3.2.1 BACT Baseline.

This boiler will be subject to the *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, 40 CFR 60 Subpart Dc. This subpart applies to steam generating units that have a maximum design heat input capacity of 100 million Btu per hour or less, but greater than or equal to 10 million Btu/hr. This subpart establishes emission standards for NO_x, PM, and SO_2 emissions from affected boilers. However, while this subpart requires initial notifications of the start of construction and initial startup, there are no applicable emission standards for affected boilers that fire only natural gas.

3.2.2 STEP 1. Identify All Available Control Technologies.

Table D3-4 is a summary of NO_x emission limits for natural gas-fired auxiliary boilers from the U.S. EPA's RACT/BACT/LAER, the South Coast Air Quality Management District’s (SCAQMD) BACT guidelines, database and from recently issued permits.

TABLE D3-4. NO_x BACT limits for natural gas-fired boilers.

Facility	State	Permit Date	Heat Input, mmBtu/hr	Limit, lb/mmBtu	Averaging Period	Control Systems
Maple Creek Energy, LLC	IN	2023	96	0.037	3-hour	GCP (LNB)
Mountain State Clean Energy LLC	WV	2022	80	0.036	3-hour	GCP
Nemadji Trail Energy Center	WI	2020	100	0.011	3-hour	GCP (ULNB)
Virginia Electric and Power Company	VA	2019	88	0.011	3-hour	GCP (ULNB)
AES Huntington Beach	CA	2006	2,088	0.0061	1-hour	GCP + SCR

Footnotes

GCP means good combustion practices; LNB means low NOx burners; ULNB means ultra-low NO_x burners; SCR means selective catalytic reduction system.

Based on these recent decisions, the available control options for NO_x emissions from natural gas-fired boilers include the use of good combustion practices including low NO_x burners, ultra-low NO_x burners, and Selective Catalytic Reduction (SCR). In addition, Selective Non-Catalytic Reduction (SNCR) is an available control technology.

3.2.2.1 Good Combustion Practices.

Good combustion practices include the use of standard burners, low NO_x burners, and ultra-low NO_x burners.

3.2.2.2 Selective Catalytic Reduction (SCR).

Selective Catalytic Reduction (SCR) is a flue gas treatment technique for the reduction of NO_x emissions which uses an ammonia (NH_3) injection system and a catalytic reactor. An SCR system utilizes an injection grid which disperses NH_3 in the flue gas upstream of the catalyst. NH_3 reacts with NO_x in the presence of the catalyst to form nitrogen (gas) and water according to the following general equations:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$$

Catalysts are substances which evoke chemical reactions that would otherwise not take place, and act by providing a reaction mechanism that has a lower activation energy than the uncatalyzed mechanism. For SCR, the catalyst is usually a noble metal, a base metal (titanium or vanadium) oxide, or a zeolite-based material. Noble metal catalysts are not typically used in SCR because of their very high cost. To achieve optimum long-term NO_x reductions, SCR systems must be properly designed for each application. In addition to critical temperature considerations, the NH_3 injection rate must be carefully controlled to maintain an NH_3/NO_x molar ratio that effectively reduces NO_x. Excessive ammonia injection will result in NH_3 emissions, called ammonia slip.

SCR has the capability to make substantial reductions in NO_x emissions. For this boiler, the use of SCR is expected to reduce NO_x emissions to a level of 5 ppmdv at 3% excess oxygen, equal to 0.007 lb/mmBtu.

3.2.2.3 Selective Non-Catalytic Reduction (SNCR).

In a selective non-catalytic reduction (SNCR) control system, urea or ammonia is injected into boilers where the flue gas temperature is approximately 1,600 °F to 2,100 °F. At these temperatures, urea [$CO(NH_2)_2$] or ammonia [NH_3], reacts with NO_x, forming elemental nitrogen [N_2] and water without the need for a catalyst. The overall NO_x reduction reactions are similar to those for SCR. Multiple injection points are required to thoroughly mix the reagent in the boiler furnace. The limiting factor for an SNCR system is the ability to contact NO_x with the reagent without resulting in excessive ammonia slip, and without excessive ammonia decomposition before the NO_x emissions can be reduced. SNCR has been widely used in circulating fluidized bed (CFB) boilers where the high alkaline ash loading of the CFB boilers makes 'high dust' loading SCR systems technically infeasible. However, we are not aware of available SNCR systems for smaller package boilers. Therefore, SNCR is not a technically feasible control technology for this boiler.

3.2.3 STEP 2. Identify Technically Feasible Control Technologies.

Based on the discussion in Step 1, Good Combustion Practices using standard burners, low NO_x burners, ultra-low NO_x burners, and Selective Catalytic Reduction (SCR) are technically feasible control options. Selective non-catalytic reduction (SNCR) is not an available control option for this boiler.

TABLE D3-5. Technical feasibility of the available NO_x control technologies.

Control Technology	Technical Feasibility	Basis
1. Good Combustion Practices using standard burners.	Feasible	Available
2. Good Combustion Practices using Low NO_x burners (LNB).	Feasible	Available.
3. Good Combustion Practices using Ultra-Low NO_x burners (ULNB).	Feasible	Available.
4. Selective Catalytic Reduction (SCR).	Feasible	Available.
5. Selective non-catalytic reduction (SNCR).	Infeasible	Not an available control technology.

3.2.4 STEP 3. Rank the Technically Feasible Technologies.

Table D3-6 is a ranking of the technically feasible control options..

TABLE D3-6. Ranking of the technically feasible NO_x control technologies.

Control Technology	Emission Rate, lb/mmBtu	Emission Rate, ppmdv at 3% O_2
1. GCP + Selective Catalytic Reduction (SCR).	0.007	5
2. Good Combustion Practices using Ultra-Low NO_x burners (ULNB).	0.011	9
3. Good Combustion Practices using Low NO_x burners (LNB).	0.037	30
4. Good Combustion Practices using standard burners.	0.10	75

Note that while ultra-low NO_x burners (ULNB) are technically feasible for this auxiliary boiler, the use of ULNB will have significant operational issues, including reduced ability to operate the boiler at loads below approximately 40% of the maximum rated heat input. Furthermore, ULNB can introduce flame instability problems which can affect the operability and availability of the auxiliary boiler.

3.2.5 STEP 4. Evaluate the Most Effective Controls.

The use of an SCR system in combination with low NO_x burners will reduce NO_x emissions from 30 ppmdv to 5 ppmdv, and by 1.35 tons per year, from 1.67 tons per year to 0.32 tons per year.

However, an SCR control system would have a significant cost. The U.S. EPA's *Air Pollution Control Cost Manual*, Chapter 2, Selective Catalytic Reduction, June 2019 provides data on the costs of SCR systems for industrial boilers[8]. Table 2.1b of this report indicates capital costs for natural gas-fired industrial boilers in the range of 10 – 100 mmBtu per hour have SCR capital costs (expressed in 1999 dollars) of $4,000 to $8,000 per mmBtu. For this boiler, that would be equal to capital costs of $360,000 to $720,000 in 1999 dollars, or $720,000 to $1,440,000 in 2025 dollars. Based on a 7% interest rate and a project life of 20 years, the capital recovery factor for this investment is 0.0944. Therefore, the annual cost to pay for the capital investment would be $68,000 to $136,000 per year. For a NO_x reduction of 1.35 tons per year, the cost effectiveness of an SCR control system, ***based on ONLY the capital investment***, would be $50,370 to $100,740 per ton of NO_x controlled.

The South Coast Air Quality Management District's BACT maximum cost effectiveness value for NO_x emissions in 2025 was $41,412 per ton of average cost effectiveness, and $124,020 per ton for the incremental cost effectiveness. The control cost effectiveness of an SCR system for this boiler would be much more than these values. Therefore, SCR is not an economically feasible NO_x control technology for this auxiliary boiler.

3.2.6 STEP 5. Proposed Nitrogen Oxides (NO_x) BACT Determination.

Based on this analysis, APS has concluded that the use of good combustion practices including the use of low NO_x burners represents the best available control technology (BACT) for the control of NO_x emissions from the proposed auxiliary boiler. APS proposes the following as BACT for NO_x emissions from this boiler:

1. Nitrogen oxides (NO_x) emissions may not exceed 0.037 lb/mmBtu based on a 3-hour average.

[8] Available at scrcostmanualchapter7thedition_2016revisions2017.pdf .

3.3 Particulate Matter, PM_{10}, and $PM_{2.5}$ Control Technology Review.

Emissions of particulate matter (PM), PM with particle sizes less than 10 microns (PM_{10}), and PM with particle sizes less than 2.5 microns ($PM_{2.5}$) from natural gas-fired boilers result from PM in the combustion air, from ash in the fuel and from products of incomplete combustion. Since natural gas has virtually no inorganic ash, fuel ash is not a significant source of PM emissions. As a result, the primary sources of PM emissions from this boiler is expected to result from products of incomplete combustion and particulate matter in the ambient air.

PM which exists as a solid or liquid at temperatures of approximately 250 ^{o}F are measured using U.S. EPA's Reference Method 5 or 17 and are commonly referred to as "front half" emissions. PM which exists as a solid or liquid at the lower temperature of 32 ^{o}F are measured using U.S. EPA's Reference Method 202, and is commonly referred to as "back half" or "condensable" PM. Condensable PM may include acid gases such as sulfuric acid mist, volatile organic compounds (VOC) and other materials, but does not include condensed water vapor.

3.3.1 BACT Baseline.

This boiler will be subject to the *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, 40 CFR 60 Subpart Dc. This subpart applies to steam generating units that have a maximum design heat input capacity of 100 million Btu per hour or less, but greater than or equal to 10 million Btu/hr. This subpart establishes emission standards for NO_x, PM, and SO_2 emissions from affected boilers. However, there are no applicable emission standards for affected boilers that fire only natural gas.

3.3.2 STEP 1. Identify All Available Control Technologies.

Table D3-7 is a summary of NO_x emission limits for natural gas-fired auxiliary boilers from the U.S. EPA's RACT/BACT/LAER, the South Coast Air Quality Management District's (SCAQMD) BACT guidelines, database and from recently issued permits.

TABLE D3-7. NO_x BACT limits for natural gas-fired boilers.

Facility	State	Permit Date	Heat Input, mmBtu/hr	Limit, lb/mmBtu	Averaging Period	Control Systems
Maple Creek Energy, LLC	IN	2023	96	0.0075	3-hour	GCP + PNG
Mountain State Clean Energy LLC	WV	2022	80	0.008	3-hour	GCP + PNG
Nemadji Trail Energy Center	WI	2020	100	0.01	3-hour	GCP + PNG
Virginia Electric and Power Company	VA	2019	88	No Numeric Limit	-	GCP + PNG

Footnotes

GCP means good combustion practices; PNG means pipeline natural gas as fuel.

The following PM, PM_{10}, and $PM_{2.5}$ control technologies were identified for boilers:

1. Good Combustion Practices including the use of standard burners, low NO_x burners, and ultra-low NO_x burners.
2. Low Ash / Low Sulfur Fuel (i.e., natural gas and/or distillate fuel oil).
3. Post combustion control systems including fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, cyclones, and multiclones.

3.3.3 STEP 2. Identify Technically Feasible Control Technologies.

The use of Good Combustion Practices and low ash and low sulfur fuels, i.e. natural gas, are technically feasible PM control options and are the only identified controls required in the permits in Table D4-7.

There is no evidence that the use of post combustion PM control systems such as fabric filter baghouses could reduce the already very low PM emission rates from natural gas-fired boilers. We are not aware of any natural gas-fired boiler required to utilize post combustion PM control systems. Therefore, fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, and mechanical systems such as cyclones and multiclones are not technically feasible control technologies for the control of PM emissions from the proposed natural gas-fired boiler.

3.3.4 STEP 3. Rank the Technically Feasible Technologies.

Based on the above analysis, the use of good combustion practices in combination with the use of pipeline quality natural gas are technically feasible control options for this heater. From Table D4-7, the use of these controls is expected to achieve PM, PM_{10}, and $PM_{2.5}$ emission rates in the range of 0.0075 to 0.01 lb/mmBtu.

3.3.5 STEP 4. Evaluate the Most Effective Controls.

APS proposes utilizing the use of low ash and low sulfur fuel (natural gas) in combination with good combustion practices as the best available control technology (BACT). Because this is the highest level of control available for this heater, further evaluation is unnecessary.

3.3.6 STEP 5. Proposed PM, PM_{10}, and $PM_{2.5}$ BACT Determination.

Based on this analysis, APS has concluded that the use of low ash and low sulfur fuel (pipeline quality natural gas) in combination with good combustion practices represents the best available control technology (BACT) for the control of PM, PM_{10}, and $PM_{2.5}$ emissions from the proposed auxiliary boiler. APS proposes the following as BACT for PM, PM_{10}, and $PM_{2.5}$ emissions from this boiler:

1. PM, PM_{10}, and $PM_{2.5}$ emissions shall be controlled by utilizing pipeline quality natural gas as the fuel in the auxiliary boiler.

3.4 Volatile Organic Compound (VOC) Control Technology Review.

Like carbon monoxide (CO), volatile organic compound (VOC) is emitted from natural gas-fired boilers as a result of incomplete combustion. Therefore, the most direct approach for reducing VOC emissions and also reduce the other related pollutants is to improve combustion. Incomplete combustion also leads to emissions of organic hazardous air pollutants (HAP) such as formaldehyde. VOC and organic HAP emissions may also be reduced using post combustion air quality control systems.

3.4.1 BACT Baseline.

There are no NSPS or SIP requirements for the control of VOC emissions from natural gas-fired boilers.

3.4.2 STEP 1. Identify All Available Control Technologies.

Table D3-8 is a summary of VOC emission limits for natural gas-fired boilers from the U.S. EPA's RACT/BACT/LAER database, the South Coast Air Quality Management District's (SCAQMD) BACT guidelines, and from recently issued permits.

TABLE D3-8. VOC BACT limits for natural gas-fired boilers.

Facility	State	Permit Date	Heat Input, mmBtu/hr	Limit, lb/mmBtu	Averaging Period	Control Systems
Maple Creek Energy, LLC	IN	2023	96	0.0034	3-hour	GCP
Mountain State Clean Energy LLC	WV	2022	80	0.007	3-hour	GCP
Nemadji Trail Energy Center	WI	2020	100	0.0027	3-hour	GCP + OC
Virginia Electric and Power Company	VA	2019	88	0.005	3-hour	GCP
AES Huntington Beach	CA	2006	2,088	n/a		

Footnotes

GCP means good combustion practices; OC means oxidation catalyst system.

Based on these recent decisions and a review of current VOC control technologies, the available control options for VOC emissions from natural gas-fired boilers are the same as for CO emissions, and include the use of good combustion practices and the use of oxidation catalysts as post combustion control systems. Good combustion practices includes standard burners, low NO_x burners, and ultra-low NO_x burners.

3.4.3 STEP 2. Identify Technically Feasible Control Technologies.

Each of the available control options identified above including good combustion practices and oxidation catalyst systems are technically feasible VOC control technologies for the proposed auxiliary boiler.

3.4.4 STEP 3. Rank the Technically Feasible Control Technologies.

The highest level of control and lowest emission rate from the auxiliary boiler is the use of good combustion practices in combination with an oxidation catalyst system. However, while oxidation catalysts are very effective at oxidizing CO to CO_2, they are much less effective at oxidizing VOCs to CO_2 and H_2O. From Table D3-8, the lowest permitted emission limits of 0.0027 lb/mmBtu. And from Table D3-2, the other boilers are permitted at a CO emission rate of 0.0034 to 0.007 lb/mmBtu. Therefore, the lowest BACT limits in Table D3-2 are based on oxidation catalyst control efficiencies of approximately 50%. This is a reasonable VOC control efficiency for oxidation catalyst systems.

3.4.5 STEP 4. Evaluate the Most Effective Controls.

The use of an oxidation catalyst system will reduce VOC emissions from 0.0055 lb/mmBtu to 0.0027 lb/mmBtu, equal to a reduction of 0.13 tons per year, from 0.25 tons per year to 0.12 tons per year.

However, as noted for the CO analysis, an oxidation catalyst control system would have a significant cost. Table D3-3 is a summary of the estimated equipment costs for an oxidation catalyst system. From Table D3-3, an oxidation catalyst system would have a purchased equipment cost of $518,000 in 2026 dollars. Based on a 7% interest rate and a project life of 20 years, the capital recovery factor for this investment is 0.0944. Therefore, the annual cost to pay for the capital investment is $48,900 per year. For a VOC reduction of 0.13 tons per year, the cost effectiveness of an oxidation catalyst control system based on ONLY the capital investment would be:

$$\text{Average Cost Effectiveness (\$ per ton removed)} = \frac{\text{Control option annualized cost}}{\text{Baseline emission rate} - \text{Control option emissions rate}}$$

$$\text{Average Cost Effectiveness (\$ per ton removed)} = \frac{\$48{,}900}{0.13\text{ tons}} = \$376{,}000 \text{ per ton of VOC reduced}$$

This is a very high control cost for the use of oxidation catalysts to control VOC emissions, especially since this cost is based only on the capital investment cost, and does not include other operating and maintenance (O&M) costs such as increased fan electric power requirements and the periodic replacement of the catalyst. Based on these high costs, an oxidation catalyst control system is not an economically feasible control technology for these boilers. The South Coast Air Quality Management District's BACT maximum cost effectiveness value for VOC emissions in 2025 was $43,800 per ton of average cost effectiveness. The control cost effectiveness of an oxidation catalyst for this boiler would be much more than these values. Therefore, an oxidation catalyst system is not an economically feasible VOC control technology for this auxiliary boiler.

Note that the same oxidation catalyst system can control both CO and VOC emissions. The combined emission reductions can be "normalized" to VOC equivalent by multiplying the CO emission reduction by the ratio of the maximum cost effectiveness for CO emissions divided by the maximum cost effectiveness for VOC emissions:

$$\text{CO Reduction (as VOC)} = 1.6 \text{ ton CO} \times \frac{\$867}{\text{ton CO}} \times \frac{\text{ton VOC}}{\$43{,}797} = 0.03 \text{ ton VOC (equivalent)}$$

Therefore, the total combined VOC emission reduction for CO and VOC emissions, expressed as the VOC equivalent is 0.13 + 0.03 = 0.16 ton VOC/year, and the cost effectiveness for both pollutants ***combined*** is $306,000 per ton of pollutant controlled, expressed as VOC emissions. This combined cost effectiveness is also much higher than the SCAQMD BACT maximum cost effectiveness value for VOC emissions in 2025 of $43,800 per ton of average cost effectiveness. Therefore, an oxidation catalyst system is also not an economically feasible combined CO and VOC control technology for this auxiliary boiler.

3.4.6 STEP 5. Proposed VOC BACT Determination.

Based on this analysis, APS has concluded that the use of good combustion practices including the use of ultra-low NO_x burners represents the best available control technology (BACT) for the control of VOC emissions from the proposed auxiliary boiler. APS proposes the following as BACT for VOC emissions from this boiler:

1. Volatile organic compound (VOC) emissions may not exceed 0.0055 lb/mmBtu based on a 3-hour average.

3.5 Greenhouse Gas (GHG) Emissions Control Technology Review.

GHG emissions from natural gas-fired boilers include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Under 40 CFR Part 98, Table C-1, the CO_2 emission factor for natural gas combustion is 53.06 kg per mmBtu, equal to 116.98 pounds per million Btu, based on the higher heating value (HHV) of natural gas. Methane emissions result from incomplete combustion. Table C-2 lists a methane emission factor for natural gas combustion of 0.001 kg/mmBtu (0.0022 lb/mmBtu). The potential emission rate for methane is then multiplied by its global warming potential of 28 to determine the total CO_2e emissions, equal to 0.062 lb CO_2e per mmBtu of heat input. Nitrous oxide (N_2O) emissions result primarily from low temperature combustion. Table C-2 lists a default N_2O emission factor for natural gas combustion of 0.0001 kg/mmBtu (0.00022 lb/mmBtu). The potential emission rate for N_2O is then multiplied by its global warming potential of 265 to determine the total CO_2e emissions, equal to 0.058 lb CO_2e per mmBtu.

Potential GHG emissions for the auxiliary boiler are detailed in Table D4-1. Potential CO_2 and total GHG emissions based on an operational limit equal to 90,000 mmBtu/year of natural gas use, equal to 5,264 and 5,269 tons per year, respectively. Therefore, CO_2 emissions account for 99.9% of the total potential GHG emissions.

Because CO_2 emissions account for 99.9% of the GHG emissions from this boiler, this control technology review for GHG emissions will focus on CO_2 emissions.

3.5.1 BACT Baseline.

There are no performance standards or other regulatory requirements for GHG emissions from this boiler.

3.5.2 STEP 1. Identify All Available Control Technologies.

Table D3-9 is a summary of CO_2 or GHG emission limits for natural gas-fired auxiliary boilers from the U.S. EPA's RACT/BACT/LAER, the South Coast Air Quality Management District's (SCAQMD) BACT guidelines database, and from recently issued permits.

TABLE D3-9. GHG BACT limits for natural gas-fired boilers.

Facility	State	Permit Date	Heat Input, mmBtu/hr	Limit	Control Systems
Maple Creek Energy, LLC	IN	2023	96	11,244 ton/yr	NG Fuel
Mountain State Clean Energy LLC	WV	2022	80	131.4 lb/mmBtu	PNG + GCP
Nemadji Trail Energy Center	WI	2020	100	160 lb/mmBtu	PNG
Virginia Electric and Power Company	VA	2019	88	Pipeline Quality Natural Gas	PNG + GCP

Footnotes

GCP means good combustion practices; PNG means pipeline quality natural gas.

3.5.3 STEP 2. Identify Technically Feasible Control Technologies.

The use of low carbon containing fuels is a technically feasible CO_2 control options for this boiler, and the design fuel for this boiler, natural gas, is the lowest CO_2 emitting fossil fuel. Good combustion practices are also a technically feasible control technology for this boiler. Note that this boiler will be subject to the *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* under 40 CFR Part 63, Subpart DDDDD. In accordance with 40 CFR §63.7500(a) and Table 3 to Subpart DDDDD, because this boiler is rated at more than 10.0 mmBtu per hour, this boiler will require a tune-up biennially as specified in 40 CFR § 63.7540.

Oxidation catalysts are a technically feasible control technology for this boiler, but as discussed in the CO and VOC analyses, oxidation catalysts are not an economically feasible control technology.

With respect to carbon capture and sequestration (CCS), as noted in the GHG analyses for the simple and combined cycle CTs, for CCS to be technically feasible, all three of the CCS steps must be technically feasible. The technical feasibility of CCS depends on the availability of appropriate geological sequestration sites in the vicinity of the plant. And as noted, the closest possible geologic carbon sequestration sites are at least 200 miles from the Desert Sun Power Plant, and these closest sites have not been verified as either suitable or available. In any case, a CO_2 pipeline would be required which would stretch for hundreds of miles, and access to an appropriate sequestration site would still be required. Based on these facts, CCS is not a technically feasible control technology for the control of GHG emissions from this boiler.

3.5.4 STEP 3. Rank the Technically Feasible Control Technologies.

For CO_2 emissions, the use of natural gas for this boiler is the lowest technically feasible carbon containing fuel and is therefore the top ranked level of control for low carbon containing fuels. Good combustion practices is also a technically feasible control technology for this boiler. This combination of controls will limit GHG emissions to no more than 120 lb/mmBtu.

3.5.5 STEP 4. Evaluate the Most Effective Controls.

The use of a low carbon containing fuel - natural gas – combined with good combustion practices are appropriate technologies for this boiler and will not have adverse environmental or economic impacts. Therefore, these controls are an appropriate basis for BACT for the control of GHG emissions.

3.5.6 STEP 5. Proposed GHG BACT Determination.

Based on this analysis, APS has concluded that the use of pipeline quality natural gas in combination with good combustion practices represents the best available control technology (BACT) for the control of GHG emissions from the proposed auxiliary boiler. APS proposes the following as BACT for GHG emissions from this boiler:

1. Greenhouse gas emissions may not exceed 120 pounds of CO_2e per million Btu of heat input.
2. The auxiliary boiler may only use natural gas as a fuel.

Chapter 4. Natural Gas Heater Control Technology Review.

The Desert Sun Power Plant will include one natural gas-fired natural gas heater with a maximum rated heat input capacity of 45 mmBtu per hour. Table D4-1 summarizes the potential emissions for the natural gas-fired natural gas heater based on 8,760 hours per year of operation and the BACT limits in this analysis.

TABLE D4-1. Potential emissions for the natural gas-fired heater.

Pollutant		Emission Factor		Heat Input	Potential to Emit	
		lb/mmcf	lb/mmBtu	mmBtu/hr	lb/hr	ton/year
Carbon Monoxide	CO	40.0	0.040	45	1.80	7.88
Nitrogen Oxides	NO_x	11.0	0.011	45	0.50	2.17
Particulate Matter	PM	7.6	0.0076	45	0.342	1.50
Particulate Matter	PM_{10}	5.0	0.005	45	0.225	0.99
Particulate Matter	$PM_{2.5}$	5.0	0.005	45	0.225	0.99
Sulfur Dioxide	SO_2	0.6	0.0006	45	0.0270	0.12
Vol. Org. Cmpds	VOC	5.5	0.0055	45	0.248	1.08
Sulfuric Acid Mist	H_2SO_4		0.00006	45	0.0027	0.012
Fluorides (as HF)	HF			45	0.000000	0.00
Lead	Pb	0.0005	0.0000005	45	0.000023	0.00010
Carbon Dioxide	CO_2	116,976	117.0	45	5,263.9	23,056.0
Greenhouse Gases	CO_2e	117,096	117.1	45	5,269.3	23,079.7

Footnotes

1. Potential emissions are based on 8,760 hours per year of operation.

2. CO and NO_x emissions are based on concentrations of 50 and 9 ppmdv at 3% O_2, respectively.

3. Emission factors for uncontrolled PM, SO_2, and lead (Pb) emissions are for uncontrolled natural gas-fired boilers from the U.S. EPA document *AP-42, Compilation of Air Pollutant Emission Factors*, 5th Edition, section 1.4, Table 1.4-1. The emission rate in pounds per million cubic feet of gas (lb/mmcf) was converted to pounds per million Btu based on a natural gas heat content of 1,000 mmBtu per mmcf.

4. Emission factors for uncontrolled PM_{10} and $PM_{2.5}$ are from the manufacturer.

5. Sulfuric acid mist emissions are based on 10% conversion of SO_2 to SO_3.

6. Natural gas does not contain significant amounts of fluorine. Therefore, fluoride emissions are expected to be insignificant.

7. Greenhouse gas (GHG) emissions are based on the emission factors for CO_2, N_2O and CH_4 are from 40 CFR 98, Tables C-1 and C-2. The CO_2e factors are from 40 CFR 98, Subpart A, Table A-1.

4.1 Carbon Monoxide (CO) Control Technology Review.

Carbon monoxide (CO) is emitted from natural gas-fired heaters as a result of incomplete combustion. Therefore, the most direct approach for reducing CO emissions and also reduce the other related pollutants is to improve combustion. Incomplete combustion also leads to emissions of volatile organic compounds (VOC) and organic hazardous air pollutants (HAP) such as formaldehyde. CO emissions as well as VOC and organic HAP emissions may also be reduced using post combustion air quality control systems.

4.1.1 BACT Baseline.

There are no applicable New Source Performance Standards (NSPS) or local air pollution control requirements for CO emissions from this heater.

4.1.2 STEP 1. Identify All Available Control Technologies.

Table D4-2 is a summary of CO emission limits for natural gas-fired heaters and auxiliary boilers from the U.S. EPA's RACT/BACT/LAER, the South Coast Air Quality Management District’s (SCAQMD) BACT guidelines database, and from recently issued permits. There are limited numbers of reviews for natural gas heaters. Note that the Nemadji Trail Energy Center (Wisconsin) includes a natural gas heater rated at 10 mmBtu per hour with a BACT limit for CO emissions of 0.08 lb/mmBtu.

TABLE D4-2. CO BACT limits for natural gas-fired heaters and boilers.

Facility	State	Permit Date	Heat Input, mmBtu/hr	Limit, lb/mmBtu	Averaging Period	Control Systems
Maple Creek Energy, LLC	IN	2023	96	0.037	3-hour	GCP
Mountain State Clean Energy LLC	WV	2022	80	0.039	3-hour	GCP
Nemadji Trail Energy Center (boiler)	WI	2020	100	0.0037	3-hour	GCP + OC
Nemadji Trail Energy Center (heater)	WI	2020	10	0.08	3-hour	GCP + PNG
Virginia Electric and Power Company	VA	2019	88	0.037	3-hour	GCP
AES Huntington Beach	CA	2006	2,088	0.0037	1-hour	OC

Footnotes

GCP means good combustion practices; OC means oxidation catalyst system.

Based on these recent decisions and a review of current CO control technologies, the available control options for CO (and VOC) emissions from natural gas-fired boilers include the use of good combustion practices and the use of oxidation catalysts as post combustion control systems. Good combustion practices includes standard burners and low NO_x burners.

4.1.3 STEP 2. Identify Technically Feasible Control Technologies.

Each of the available control options identified above including good combustion practices and oxidation catalyst systems are technically feasible CO control technologies for the proposed heater.

4.1.4 STEP 3. Rank the Technically Feasible Control Technologies.

The highest level of control and lowest emission rate from this heater is the use of good combustion practices in combination with an oxidation catalyst system. From Table D4-2, the lowest permitted emission limits of 0.0037 lb/mmBtu is equal to a CO concentration of 5 parts per million on a dry volume basis corrected to 3% excess oxygen (ppmdv at 3% O_2). And from Table D4-2, the other boilers are permitted at a CO emission rate of 0.037 lb/mmBtu, equal to a CO concentration of 50 ppmdv at 3% O_2. Note that at least one heater has a much higher CO emission limit of 0.08 lb/mmBtu.

4.1.5 STEP 4. Evaluate the Most Effective Controls.

The use of an oxidation catalyst system will reduce CO emissions from 50 ppmdv to 5 ppmdv, or from 7.8 tons per year to 0.8 tons per year.

However, an oxidation catalyst control system would have a significant cost. Using the same method as in Chapter 3 and Table 3-3 for the auxiliary boiler, an oxidation catalyst system for this heater would have a purchased equipment cost of $448,000 in 2026 dollars. Based on a 7% interest rate and a project life of 20 years, the capital recovery factor for this investment is 0.0944. Therefore, the annual cost to pay for the capital investment is $42,300 per year. For a CO reduction of 7.0 tons per year, the cost effectiveness of an oxidation catalyst control system based on ONLY the capital investment would be $6,040 per ton of CO controlled.

This is a very high control cost for the use of oxidation catalysts to control CO emissions, especially since this cost is based only on the capital investment cost, and does not include other operating and maintenance (O&M) costs such as increased fan electric power requirements and the periodic replacement of the catalyst. Based on these high costs, an oxidation catalyst control system is not an economically feasible control technology for these boilers. The South Coast Air Quality Management District's BACT maximum cost effectiveness value for CO emissions in 2025 was $867 per ton of average cost effectiveness, and $2,493 for the incremental cost effectiveness. The control cost effectiveness of an oxidation catalyst for this natural gas heater would be much more than these values. Therefore, an oxidation catalyst system is not an economically feasible CO control technology for this heater.

4.1.6 STEP 5. Proposed Carbon Monoxide (CO) BACT Determination.

Based on this analysis, APS has concluded that the use of good combustion practices including the use of low NO_x burners represents the best available control technology (BACT) for the control of CO emissions from the proposed heater. APS proposes the following as BACT for CO emissions from this heater:

1. Carbon monoxide (CO) emissions may not exceed 0.04 lb/mmBtu based on a 3-hour average.

4.2 Nitrogen Oxides (NO_x) Control Technology Review.

Nitrogen oxides (NO_x) consist of both nitrogen oxide (NO), and nitrogen dioxide (NO_2). During combustion, NO usually accounts for about 90% of the total NO_x emissions. However, since NO is converted to NO_2 in the atmosphere, the mass emission rate of NO_x is usually reported as NO_2.

NO_x is formed during combustion by two major mechanisms; thermal formation (Thermal NO_x), and fuel formation (Fuel NO_x). Thermal NO_x results from the high temperature oxidation of nitrogen (N_2) and oxygen (O_2). In this mechanism, N_2 is supplied from air, which is 78% N_2 by volume. Thermal NO_x formation increases exponentially with temperature, becoming significant at temperatures above 2,800 °F. Fuel NO_x results from the oxidation of organic nitrogen compounds in the fuel. Because fuel bound nitrogen is more easily converted to NO_x during combustion, nitrogen levels in fuel have a significant impact on NO_x formation. However, since natural gas has only trace organic nitrogen compounds, thermal NO_x is the primary source of NO_x emissions from natural gas-fired boilers and heaters.

4.2.1 BACT Baseline.

There are no applicable New Source Performance Standards (NSPS) or local air pollution control requirements for NO_x emissions from this heater.

4.2.2 STEP 1. Identify All Available Control Technologies.

Table D4-3 is a summary of NO_x emission limits for natural gas-fired heaters and auxiliary boilers from the U.S. EPA's RACT/BACT/LAER, the South Coast Air Quality Management District’s (SCAQMD) BACT guidelines, database and from recently issued permits. There are limited numbers of reviews for natural gas heaters except the Nemadji Trail Energy Center (Wisconsin) includes a natural gas heater rated at 10 mmBtu per hour with a BACT limit for NO_x emissions of 0.049 lb/mmBtu, equal to 40 ppmdv at 3% O_2.

TABLE D4-3. NO_x BACT limits for natural gas-fired boilers.

Facility	State	Permit Date	Heat Input, mmBtu/hr	Limit, lb/mmBtu	Averaging Period	Control Systems
Maple Creek Energy, LLC	IN	2023	96	0.037	3-hour	GCP (LNB)
Mountain State Clean Energy LLC	WV	2022	80	0.036	3-hour	GCP
Nemadji Trail Energy Center	WI	2020	100	0.011	3-hour	GCP (ULNB)
Nemadji Trail Energy Center (heater)	WI	2020	10	0.049	3-hour	GCP (LNB)
Virginia Electric and Power Company	VA	2019	88	0.011	3-hour	GCP (ULNB)
AES Huntington Beach	CA	2006	2,088	0.0061	1-hour	GCP + SCR

Footnotes

GCP means good combustion practices; LNB means low NOx burners; ULNB means ultra-low NOx burners; OC means oxidation catalyst system.

Based on these recent decisions, the available control options for NO_x emissions from natural gas-fired boilers include the use of good combustion practices including low NO_x burners, ultra-low NO_x burners, Selective Catalytic Reduction (SCR). In addition, Selective Non-Catalytic Reduction (SNCR) is an available control technology.

4.2.2.1 Good Combustion Practices.

Good combustion practices include the use of standard burners, low NO_x burners, and ultra-low NO_x burners are technically feasible control technologies.

4.2.2.2 Selective Catalytic Reduction (SCR).

Selective Catalytic Reduction (SCR) is a flue gas treatment technique for the reduction of NO_x emissions which uses an ammonia (NH_3) injection system and a catalytic reactor. An SCR system utilizes an injection grid which disperses NH_3 in the flue gas upstream of the catalyst. NH_3 reacts with NO_x in the presence of the catalyst to form nitrogen (gas) and water according to the following general equations:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$$

Catalysts are substances which evoke chemical reactions that would otherwise not take place, and act by providing a reaction mechanism that has a lower activation energy than the uncatalyzed mechanism. For SCR, the catalyst is usually a noble metal, a base metal (titanium or vanadium) oxide, or a zeolite-based material. Noble metal catalysts are not typically used in SCR because of their very high cost. To achieve optimum long-term NO_x reductions, SCR systems must be properly designed for each application. In addition to critical temperature considerations, the NH_3 injection rate must be carefully controlled to maintain an NH_3/NO_x molar ratio that effectively reduces NO_x. Excessive ammonia injection will result in NH_3 emissions, called ammonia slip.

SCR has the capability to make substantial reductions in NO_x emissions.

4.2.2.3 Selective Non-Catalytic Reduction (SNCR).

In a selective non-catalytic reduction (SNCR) control system, urea or ammonia is injected into boilers where the flue gas temperature is approximately 1,600 °F to 2,100 °F. At these temperatures, urea [$CO(NH_2)_2$] or ammonia [NH_3], reacts with NO_x, forming elemental nitrogen [N_2] and water without the need for a catalyst. The overall NO_x reduction reactions are similar to those for SCR. Multiple injection points are required to thoroughly mix the reagent into the boiler furnace. The limiting factor for an SNCR system is the ability to contact NO_x with the reagent without resulting in excessive ammonia slip, and without excessive ammonia decomposition before the NO_x emissions can be reduced.

SNCR has been widely used in circulating fluidized bed (CFB) boilers where the high alkaline ash loading of the CFB boilers makes ‘high dust’ loading SCR systems technically infeasible. However, we are not aware of available SNCR systems for very small process heaters. We are not aware of the application of SNCR to any process heaters either in the U.S. or worldwide. Therefore, SNCR is not a technically feasible control technology for natural gas-fired natural gas heater.

4.2.3 STEP 2. Identify Technically Feasible Control Technologies.

Based on the discussion in Step 1, Good Combustion Practices using standard burners, low NO_x burners, ultra-low NO_x burners, and Selective Catalytic Reduction (SCR) are technically feasible control options. Selective non-catalytic reduction (SNCR) is not an available control option for this boiler.

4.2.4 STEP 3. Rank the Technically Feasible Technologies.

Table D4-4 is a ranking of the technically feasible control options.

TABLE D4-4. Ranking of the technically feasible NO_x control technologies.

Control Technology	Emission Rate, lb/mmBtu	Emission Rate, ppmdv at 3% O_2
1. GCP + SCR.	0.007	5
2. GCP using Ultra-Low NO_x burners (ULNB).	0.011	9
3. GCP using Low NO_x burners (LNB).	0.037	30
4. Good using standard burners.	0.10	75

4.2.5 STEP 4. Evaluate the Most Effective Controls.

The use of an SCR system in combination with low NO_x burners will reduce NO_x emissions from 9 ppmdv to 5 ppmdv, or from 2.17 tons per year to 1.38 tons per year, or a NO_x reduction of 0.8 tons per year. However, an SCR control system would have a significant cost. Using the control costs as discussed in Chapter 3 of this control technology review, SCR for this heater would have a capital cost of $360,000 to $720,000 in 2025 dollars. Based on a 7% interest rate and a project life of 20 years, the annual cost to pay for the capital investment would be $34,000 to $68,000 per year. For a NO_x reduction of 0.8 tons per year, the cost effectiveness of an SCR control system would be $42,000 to $85,000 per ton of NO_x controlled, ***based on ONLY the capital investment***.

The South Coast Air Quality Management District's BACT maximum cost effectiveness value for NO_x emissions in 2025 was $41,806 per ton of average cost effectiveness, and $125,200 per ton for the incremental cost effectiveness. The control cost effectiveness of an SCR system for this heater would exceed these values. Therefore, SCR is not an economically feasible NO_x control technology for this heater.

4.2.6 STEP 5. Proposed Nitrogen Oxides (NO_x) BACT Determination.

Based on this analysis, APS has concluded that the use of good combustion practices including the use of ultra-low NO_x burners represents the best available control technology (BACT) for the control of NO_x emissions from the proposed natural gas-fired natural gas heater. APS proposes the following as BACT for NO_x emissions from this heater:

1. Nitrogen oxides (NO_x) emissions may not exceed 0.011 lb/mmBtu based on a 3-hour average.

4.3 Particulate Matter, PM_{10}, and $PM_{2.5}$ Control Technology Review.

Emissions of particulate matter (PM), PM with particle sizes less than 10 microns (PM_{10}), and PM with particle sizes less than 2.5 microns ($PM_{2.5}$) from natural gas combustion results from PM in the combustion air, from ash in the fuel and from products of incomplete combustion. Since natural gas has virtually no inorganic ash, fuel ash is not a significant source of PM emissions. As a result, the primary sources of PM emissions from this boiler is expected to result from products of incomplete combustion and particulate matter in the ambient air.

PM which exists as a solid or liquid at temperatures of approximately 250 ^{o}F are measured using U.S. EPA's Reference Method 5 or 17 and are commonly referred to as "front half" emissions. PM which exists as a solid or liquid at the lower temperature of 32 ^{o}F are measured using U.S. EPA's Reference Method 202, and is commonly referred to as "back half" or "condensable" PM. Condensable PM may include acid gases such as sulfuric acid mist, volatile organic compounds (VOC) and other materials, but does not include condensed water vapor.

4.3.1 BACT Baseline.

There are no applicable New Source Performance Standards (NSPS) or local air pollution control requirements for NO_x emissions from this heater.

4.3.2 STEP 1. Identify All Available Control Technologies.

Table D4-5 is a summary of NO_x emission limits for natural gas-fired auxiliary boilers and heaters from the U.S. EPA's RACT/BACT/LAER, the South Coast Air Quality Management District's (SCAQMD) BACT guidelines, database and from recently issued permits. There are limited numbers of reviews for natural gas heaters. Note that the Nemadji Trail Energy Center (Wisconsin) includes a natural gas heater rated at 10 mmBtu per hour with a BACT limit for PM emissions of 0.01 lb/mmBtu.

TABLE D4-5. NO_x BACT limits for natural gas-fired heaters and boilers.

Facility	State	Permit Date	Heat Input, mmBtu/hr	Limit, lb/mmBtu	Averaging Period	Control Systems
Maple Creek Energy, LLC	IN	2023	96	0.0075	3-hour	GCP + PNG
Mountain State Clean Energy LLC	WV	2022	80	0.008	3-hour	GCP + PNG
Nemadji Trail Energy Center	WI	2020	100	0.01	3-hour	GCP + PNG
Nemadji Trail Energy Center (heater)	WI	2020	10	0.01	3-hour	GCP + PNG
Virginia Electric and Power Company	VA	2019	88	No Numeric Limit	-	GCP + PNG

Footnotes

GCP means good combustion practices; PNG means pipeline natural gas as fuel.

The following PM, PM_{10}, and $PM_{2.5}$ control technologies were identified for boilers and process heaters:

1. Good Combustion Practices including the use of standard burners and low NO_x burners.
2. Low Ash / Low Sulfur Fuel (i.e., natural gas and/or distillate fuel oil).
3. Post combustion control systems including fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, cyclones, and multiclones.

4.3.3 STEP 2. Identify Technically Feasible Control Technologies.

The use of Good Combustion Practices and low ash and low sulfur fuels, i.e. natural gas, are technically feasible PM control options and are the only identified controls required in the permits in Table D4-4.

There is no evidence that the use of post combustion PM control systems such as fabric filter baghouses could reduce the already very low PM emission rates from natural gas-fired process heaters. We are not aware of any natural gas-fired heater required to utilize post combustion PM control systems. Therefore, fabric filter baghouses, electrostatic precipitators (ESP), wet scrubbers, and mechanical systems such as cyclones and multiclones are not technically feasible control technologies for the control of PM emissions from the proposed natural gas-fired natural gas heater.

4.3.4 STEP 3. Rank the Technically Feasible Technologies.

Based on the above analysis, the use of good combustion practices in combination with the use of pipeline quality natural gas are technically feasible control options for this heater. From Table D4-4, the use of these controls is expected to achieve PM, PM_{10}, and $PM_{2.5}$ emission rates in the range of 0.0075 to 0.01 lb/mmBtu.

4.3.5 STEP 4. Evaluate the Most Effective Controls.

APS proposes utilizing the use of low ash and low sulfur fuel (natural gas) in combination with good combustion practices as the best available control technology (BACT). Because this is the highest level of control available for this heater, further evaluation is unnecessary.

4.3.6 STEP 5. Proposed PM, PM_{10}, and $PM_{2.5}$ BACT Determination.

Based on this analysis, APS has concluded that the use of low ash and low sulfur fuel (pipeline quality natural gas) in combination with good combustion practices represents the best available control technology (BACT) for the control of PM, PM_{10}, and $PM_{2.5}$ emissions from the proposed natural gas heater. APS proposes the following as BACT for PM, PM_{10}, and $PM_{2.5}$ emissions from this heater:

1. PM, PM_{10}, and $PM_{2.5}$ emissions shall be controlled by utilizing pipeline quality natural gas as the fuel in the natural gas heater.

4.4 Volatile Organic Compound (VOC) Control Technology Review.

Like carbon monoxide (CO), volatile organic compound (VOC) is emitted from natural gas combustion as a result of incomplete combustion. Therefore, the most direct approach for reducing VOC emissions and also reduce the other related pollutants is to improve combustion. Incomplete combustion also leads to emissions of organic hazardous air pollutants (HAP) such as formaldehyde. VOC and organic HAP emissions may also be reduced using post combustion air quality control systems.

4.4.1 BACT Baseline.

There are no NSPS or SIP requirements for the control of VOC emissions from natural gas-fired heaters.

4.4.2 STEP 1. Identify All Available Control Technologies.

Table D4-6 is a summary of VOC emission limits for natural gas-fired boilers and heaters from the U.S. EPA's RACT/BACT/LAER database, the South Coast Air Quality Management District's (SCAQMD) BACT guidelines, and from recently issued permits. There are limited numbers of reviews for natural gas heaters. Note that the Nemadji Trail Energy Center (Wisconsin) includes a natural gas heater rated at 10 mmBtu per hour with a BACT limit for VOC emissions of 0.005 lb/mmBtu.

TABLE D4-6. VOC BACT limits for natural gas-fired boilers.

Facility	State	Permit Date	Heat Input, mmBtu/hr	Limit, lb/mmBtu	Averaging Period	Control Systems
Maple Creek Energy, LLC	IN	2023	96	0.0034	3-hour	GCP
Mountain State Clean Energy LLC	WV	2022	80	0.007	3-hour	GCP
Nemadji Trail Energy Center	WI	2020	100	0.0027	3-hour	GCP + OC
Nemadji Trail Energy Center (heater)	WI	2020	10	0.005	3-hour	GCP
Virginia Electric and Power Company	VA	2019	88	0.005	3-hour	GCP
AES Huntington Beach	CA	2006	2,088	n/a		

Footnotes

GCP means good combustion practices; OC means oxidation catalyst system.

Based on these recent decisions and a review of current VOC control technologies, the available control options for VOC emissions from natural gas-fired heaters are the same as for CO emissions, and include the use of good combustion practices and the use of oxidation catalysts as post combustion control systems. Good combustion practices includes standard burners, and low NO_x burners.

4.4.3 STEP 2. Identify Technically Feasible Control Technologies.

Each of the available control options identified above including good combustion practices and oxidation catalyst systems are technically feasible CO control technologies for the proposed heater.

4.4.4 STEP 3. Rank the Technically Feasible Control Technologies.

The highest level of control and lowest emission rate from this heater is the use of good combustion practices in combination with an oxidation catalyst system. From Table D5-5, the lowest permitted emission limits of 0.0027 lb/mmBtu. And from Table D5-5, the other boilers and heaters are permitted at a VOC emission rate of 0.005 lb/mmBtu, indicating an oxidation catalyst control efficiency of 50%.

4.4.5 STEP 4. Evaluate the Most Effective Controls.

The use of an oxidation catalyst system will reduce VOC emissions from 0.0055 lb/mmBtu to 0.0027 lb/mmBtu, or from 1.08 tons per year to 0.54 tons per year.

However, an oxidation catalyst control system would have a significant cost. Using the same method as in Chapter 3 and Table 3-3 for the auxiliary boiler, an oxidation catalyst system for this heater would have a purchased equipment cost of $448,000 in 2026 dollars. Based on a 7% interest rate and a project life of 20 years, the capital recovery factor for this investment is 0.0944. Therefore, the annual cost to pay for the capital investment is $42,300 per year. For a VOC reduction of 0.54 tons per year, the cost effectiveness of an oxidation catalyst control system based on ONLY the capital investment would be $78,300 per ton of CO controlled.

This is a very high control cost for the use of oxidation catalysts to control VOC emissions, especially since this cost is based only on the capital investment cost, and does not include other operating and maintenance (O&M) costs such as increased fan electric power requirements and the periodic replacement of the catalyst. Based on these high costs, an oxidation catalyst control system is not an economically feasible control technology for these boilers. The South Coast Air Quality Management District's BACT maximum cost effectiveness value for VOC emissions in 2025 was $43,800 per ton of average cost effectiveness. The control cost effectiveness of an oxidation catalyst for this heater would be much more than this value. Therefore, an oxidation catalyst system is not an economically feasible VOC control technology for this heater.

Note that the same oxidation catalyst system can control both CO and VOC emissions. The combined emission reductions can be "normalized" to VOC equivalent by multiplying the CO emission reduction by the ratio of the maximum cost effectiveness for CO emissions divided by the maximum cost effectiveness for VOC emissions:

$$\text{CO Reduction (as VOC)} = 7.1\ \text{ton CO} \times \frac{\$867}{\text{ton CO}} \times \frac{\text{ton VOC}}{\$43{,}797} = 0.14\ \text{ton VOC (equivalent)}$$

Therefore, the total combined VOC emission reduction for CO and VOC emissions, expressed as the VOC equivalent is 0.54 + 0.14 = 0.68 ton VOC/year, and the cost effectiveness for both pollutants combined is $64,400 per ton of pollutant controlled, expressed as VOC emissions. This combined cost effectiveness is also higher than the SCAQMD BACT maximum cost effectiveness value for VOC emissions in 2025 of $43,800 per ton of average cost effectiveness. Therefore, an oxidation catalyst system is also not an economically feasible combined CO and VOC control technology for this natural gas heater.

4.4.6 STEP 5. Proposed VOC BACT Determination.

Based on this analysis, APS has concluded that the use of good combustion practices including the use of low NO_x burners represents the best available control technology (BACT) for the control of VOC emissions from the proposed natural gas-fired natural gas heater. APS proposes the following as BACT for CO emissions from the natural gas heater:

1. Volatile organic compound (VOC) emissions may not exceed 0.0055 lb/mmBtu based on a 3-hour average.

4.5 Greenhouse Gas (GHG) Emissions Control Technology Review.

GHG emissions from natural gas-fired boilers and process heaters include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Under 40 CFR Part 98, Table C-1, the CO_2 emission factor for natural gas combustion is 53.06 kg per mmBtu, equal to 116.98 pounds per million Btu, based on the higher heating value (HHV) of natural gas. Methane emissions result from incomplete combustion. Table C-2 lists a methane emission factor for natural gas combustion of 0.001 kg/mmBtu (0.0022 lb/mmBtu). The potential emission rate for methane is then multiplied by its global warming potential of 28 to determine the total CO_2e emissions, equal to 0.062 lb CO_2e per mmBtu of heat input. Nitrous oxide (N_2O) emissions result primarily from low temperature combustion. Table C-2 lists a default N_2O emission factor for natural gas combustion of 0.0001 kg/mmBtu (0.00022 lb/mmBtu). The potential emission rate for N_2O is then multiplied by its global warming potential of 265 to determine the total CO_2e emissions, equal to 0.058 lb CO_2e per mmBtu.

Potential GHG emissions for the natural gas heater are detailed in Table D5-1. Potential CO_2 and total GHG emissions are 23,056 and 23,080 tons per year, respectively. Therefore, CO_2 emissions account for 99.9% of the total potential GHG emissions. ***Because CO_2 emissions account for 99.9% of the GHG emissions from this heater, this control technology review for GHG emissions will focus on CO_2 emissions.***

4.5.1 BACT Baseline.

There are no performance standards or other requirements for GHG emissions from this heater.

4.5.2 STEP 1. Identify All Available Control Technologies.

Table D5-6 is a summary of CO_2 or GHG emission limits for natural gas-fired auxiliary boilers and heaters from the U.S. EPA's RACT/BACT/LAER, the South Coast Air Quality Management District's (SCAQMD) BACT guidelines database, and from recently issued permits.

TABLE D4-7. GHG BACT limits for natural gas-fired boilers and heaters.

Facility	State	Permit Date	Heat Input, mmBtu/hr	Limit	Control Systems
Maple Creek Energy, LLC	IN	2023	96	11,244 ton/yr	NG Fuel
Mountain State Clean Energy LLC	WV	2022	80	131.4 lb/mmBtu	PNG + GCP
Nemadji Trail Energy Center	WI	2020	100	160 lb/mmBtu	PNG
Nemadji Trail Energy Center (heater)	WI	2020	10	PNG + GCP	PNG + GCP
Virginia Electric and Power Company	VA	2019	88	Pipeline Quality Natural Gas	PNG + GCP

Footnotes

GCP means good combustion practices; PNG means pipeline quality natural gas.

4.5.3 STEP 2. Identify Technically Feasible Control Technologies.

The use of low carbon containing fuels is a technically feasible CO_2 control options for this heater, and the fuel for this heater, natural gas, is the lowest CO_2 emitting fossil fuel. Good combustion practices are also a technically feasible control technology for this heater. Note that this heater will be subject to the *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* under 40 CFR Part 63, Subpart DDDDD. In accordance with 40 CFR §63.7540(a)(11), if your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater.

Oxidation catalysts are a technically feasible control technology for this heater, but as discussed in the CO and VOC analyses, oxidation catalysts are not an economically feasible control technology.

With respect to carbon capture and sequestration (CCS), as noted in the GHG analyses for the simple and combined cycle CTs, for CCS to be technically feasible, all three of the CCS steps must be technically feasible. The technical feasibility of CCS depends on the availability of appropriate geological sequestration sites in the vicinity of the plant. And as noted, the closest possible geologic carbon sequestration sites are at least 200 miles from the Desert Sun Power Plant, and these closest sites have not been verified as either suitable or available. In any case, a CO_2 pipeline would be required which would stretch for hundreds of miles, and access to an appropriate sequestration site would still be required. Based on these facts, CCS is not a technically feasible control technology for the control of GHG emissions from this heater.

4.5.4 STEP 3. Rank the Technically Feasible Control Technologies.

For CO_2 emissions, the use of natural gas is the lowest technically feasible carbon containing fuel and is therefore the top ranked level of control for low carbon containing fuels. Good combustion practices is also a technically feasible control technology for this heater. This combination of controls will limit GHG emissions to no more than 120 lb/mmBtu.

4.5.5 STEP 4. Evaluate the Most Effective Controls.

The use of a low carbon containing fuel - natural gas – combined with good combustion practices are appropriate technologies for this heater and will not have adverse environmental or economic impacts. Therefore, these controls are an appropriate basis for BACT for the control of GHG emissions.

4.5.6 STEP 5. Proposed BACT Determination.

Based on this analysis, APS has concluded that the use of pipeline quality natural gas in combination with good combustion practices represents the best available control technology (BACT) for the control of GHG emissions from the proposed natural gas-fired natural gas heater. APS proposes the following as BACT for GHG emissions from this heater:

1. Greenhouse gas emissions may not exceed 120 pounds of CO_2e per million Btu of heat input.
2. The natural gas heater may only use natural gas as a fuel.

Chapter 5. Cooling Tower Control Technology Review.

The combined cycle CTs will utilize closed cycle, air cooled condensers to condense the steam exhausted from the steam turbine. All four CTs will also utilize a Closed Cooling Water (CCW) system to provide cooling for each of the CTs and, for the combined cycle units, the steam turbine - electric generator set. The CCW will use air cooled fin-fan heat exchangers which act much like a car's radiator to provide cooling of the CCW up to an ambient temperature of approximately 110 ^{o}F. Above 110 ^{o}F, small wet cooling towers will provide supplemental cooling for each CT. This configuration will minimize the size of the wet cooling towers and minimize water consumption.

In a mechanical draft wet cooling tower, the circulating cooling water is introduced into the top of the tower. As the water falls through the tower, a fan induces an air flow in a countercurrent direction. A portion of the circulating water evaporates, cooling the remaining water. A much smaller amount of the water may be entrained in the induced air flow in the form of liquid phase droplets or mist called *drift*. When these droplets evaporate, the dissolved solids in the droplet become particulate matter. Therefore, cooling towers are sources of PM, PM_{10}, and $PM_{2.5}$ emissions.

Cooling tower PM, PM_{10}, and $PM_{2.5}$ emissions are calculated based on the circulating water flow rate, the total dissolved solids (TDS) in the circulating water, and the design drift loss according to the following equation:

$$E = kQ\left(\frac{60\text{ min}}{\text{hour}}\right)\left(\frac{8.345\text{ lb water}}{\text{gal water}}\right)\left(\frac{C_{TDS}}{10^6}\right)\left(\frac{\%DL}{100}\right)$$

Where,

E	=	Particulate matter emissions, pounds per hour, lb/hr		
Q	=	Circulating water flow rate, gallons per minute	=	4,000 gpm
C_{TDS}	=	Circulating water total dissolved solids, parts per million	=	2,000 ppm
%DL	=	Drift loss, %	=	0.0005%
k	=	particle size multiplier, dimensionless		

Total potential PM, PM_{10}, and $PM_{2.5}$ emissions are summarized in Table D5-1.

TABLE D5-1. Total potential emissions for each mechanical draft cooling tower.

POLLUTANT		*Q* Flowrate gal/min	C_{TDS} TDS Conc. ppm	%DL Drift Loss %	*k* Part. Size Multiplier	Potential Emissions lb/hr	Potential Emissions ton/yr
Particulate Matter	PM	4,000	2,000	0.0005%	1.00	0.0200	0.088
Particulate Matter	PM_{10}	4,000	2,000	0.0005%	0.705	0.0141	0.062
Particulate Matter	$PM_{2.5}$	4,000	2,000	0.0005%	0.0023	0.000045	0.00020

5.1 Particulate Matter, PM_{10}, and $PM_{2.5}$ Control Technology Review.

5.1.1 BACT Baseline.

There are no specific state implementation plan (SIP) requirements or new source performance standards for this cooling tower.

5.1.2 Step 1. Identify all available control technologies.

In a review of recently issued permits for new power plants equipped with cooling towers, drift eliminators or demisters are the only identified control technology to limit PM emissions. Drift eliminators are used at the outlet of cooling towers to reduce the amount of water droplets entrained in the air, called drift loss. Drift loss is expressed as the percent of the circulating water flowrate that is exhausted from the cooling tower as droplets. Drift eliminators are typically blades configured in a chevron pattern which cause the water droplets to impact these blades and fall back into the tower.

Drift eliminators can be designed for various levels of drift loss control. Table D5-2 is a summary of BACT emission limits for cooling towers located at electric power plants. Please note that these limits are for large, forced draft cooling towers for the steam turbine condensers. The proposed cooling towers for the Desert Sun Power Plant are much smaller towers intended for supplemental cooling. From Table D6-2, the required drift loss design requirement is 0.0005%.

TABLE D5-2. PM BACT limits for cooling towers at power plants.

Facility	State	Permit Date	Limit
Duke Energy, LLC Cayuga Generating Station	IN	2025	0.0005% DL
Mountain State Clean Energy LLC	WV	2022	0.0005% DL
Entergy Orange County Power Station	TX	2023	0.0005% DL
Virginia Electric and Power Company	VA	2019	Insignificant Emission Unit

Footnotes

DL means drift loss.

5.1.3 Step 2. Identify the technically feasible control options.

The only technically feasible control option for these mechanical draft cooling towers is the use of high efficiency drift eliminators.

5.1.4 Step 3. Rank the technically feasible control options.

The only technically feasible control option for this mechanical draft cooling tower is the use of high efficiency drift eliminators. Therefore, high efficiency drift eliminators are the top ranked control option. The highest level of control commercially available and required in other BACT determinations is 0.0005%.

5.1.5 Step 4. Evaluate the most effective controls.

The only feasible control technology for these mechanical draft cooling towers is high efficiency drift eliminators. This is an appropriate control technology for this heater and will not have adverse environmental or economic impacts. Therefore, these controls are an appropriate basis for BACT for the control of PM emissions from these cooling towers.

5.1.6 STEP 5. Proposed PM, PM_{10}, and $PM_{2.5}$ BACT Determination.

Based on this analysis, APS has concluded that the use of high efficiency drift eliminators represents the best available control technology (BACT) for the control of PM, PM_{10}, and $PM_{2.5}$ emissions from the proposed mechanical draft cooling towers. APS proposes the following as BACT for PM, PM_{10}, and $PM_{2.5}$ emissions from these cooling towers:

1. PM, PM_{10}, and $PM_{2.5}$ emissions from each cooling tower shall be controlled by utilizing high efficiency drift eliminators with a maximum design drift loss of no more than 0.0005% of the circulating water flowrate.

Chapter 6. Emergency Fire Pump Control Technology Review.

The Desert Sun Power Plant will have one new 510 horsepower diesel engine driven fire pump. This engine will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* under 40 CFR 60, Subpart IIII. These emission standards are summarized below.

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines], g/kWh (g/Hp-hr)

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009 +[3]	4.0 (3.0)	3.5 (2.6)	0.20 (0.15)

Potential air pollutant emissions for this new fire pump are summarized in Table D6-1. Potential emissions are based on 200 hours per year of operation. Potential CO, NO_x, and PM emissions are based on the above standards in Table 4 of Subpart IIII. For NO_x emissions, the standard is for the combined total of NO_x plus non-methane hydrocarbons (NMHC + NO_x). As a worst-case assumption in this analysis, potential NO_x emissions assume 100% of the emissions are NO_x emissions. Potential VOC emissions are based on the NMHC + NO_x standard and assume one-half of the total NMHC + NO_x emissions are VOC emissions.

TABLE D6-1. Potential emissions for 510 horsepower diesel engine driven fire pump.

POLLUTANT		Fuel Oil Heat Input	Power Output	Emission Factor		Potential Emissions	
		mmBtu/hr	hp	lb/mmBtu	g/hp-hr	lb/hr	ton/year
Carbon Monoxide	CO	4.20	510	0.70	2.6	2.92	0.29
Nitrogen Oxides	NO_x	4.20	510	0.80	3.0	3.37	0.34
Particulate Matter	PM	4.20	510	0.010	0.15	0.17	0.02
Particulate Matter	PM_{10}	4.20	510	0.010	0.15	0.17	0.02
Particulate Matter	$PM_{2.5}$	4.20	510	0.010	0.15	0.17	0.02
Sulfur Dioxide	SO_2	4.20	510	0.0016		0.007	0.0007
Vol. Org. Cmpds	VOC	4.20	510	0.40	1.5	1.69	0.17
Sulfuric Acid Mist	H_2SO_4	4.20	510	0.00040		0.002	0.0002
Fluorides	F	4.20	510	0.0373		0.157	0.0157
Lead	Pb	4.20	510	0.000009		0.00004	0.000004
Carbon Dioxide	CO_2	4.20	510	163.1		684.8	68.5
Greenhouse Gases	CO_2e	4.20	510	163.8		687.8	68.8

Footnotes

1. Potential emissions are based on 200 hours per year of operation at the full output of 510 hp and a diesel oil fuel oil flow of 30 gal/hr, equal to 4.2 mmBtu/hr.

2. The NOx and PM emission factors in g/hp-hr are the emission standards for stationary fire pump engines with ratings of 30 < HP < 600 in 40 CFR 60, Subpart III, Table 4. The CO emission rate is the emission standard for similar model year 2008 and earlier engines.

3. All PM emissions are also assumed to be PM_{10} and $PM_{2.5}$ emissions.

4. The SO_2 emission factor of 0.0016 lb/mmBtu is based on combustion of ultra-low sulfur fuel oil with a sulfur content of less than 15 parts per million (ppm).

5. The VOC emission factor in g/hp-hr is equal to one-half of the emission standard for NOx plus total non-methane hydrocarbons for fire pump engines with ratings of 30 < HP < 600 in 40 CFR 60, Subpart III, Table 4.

6. Sulfuric acid mist emissions are based on 25% conversion of SO_2 to sulfuric acid mist in the flue gas.

7. The lead (Pb) and fluorides emission factors are based on combustion of fuel oil from the U.S. EPA's *Compilation of Air Pollutant Emission Factors*, *AP-42*, 5th Edition, Table 1.3-10 and 1.3-11.

8. The emission factors for the greenhouse gases from fuel oil combustion, including CO_2, N_2O and CH_4 are from 40 CFR 98, Tables C-1 and C-2. The CO_2e factors are from 40 CFR 98, Subpart A, Table A-1.

Pollutant		Emission Factor	Total GHG Emission Factor	
		lb/mmBtu	CO_2e Factor[4]	lb/mmBtu
Carbon Dioxide	CO_2	163.05	1	163.052
Methane	CH_4	0.0132	25	0.331
Nitrous Oxide	N_2O	0.00132	298	0.394
TOTAL GHG EMISSIONS, AS CO_2e				**163.8**

6.1 CO Control Technology Review.

The diesel engine-driven fire pump will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* under 40 CFR 60, Subpart IIII.. These emission standards include a CO emission limit of 2.6 grams per horsepower-hour. This emission standard will ensure that these engines minimize CO emissions. CO emissions have been calculated based on the design engine rating and the CO performance standard of 2.6 grams per horsepower-hour:

$$\text{Maximum Hourly Emission Rate} = 510\ \text{hp} \times \frac{2.6\ \text{g CO}}{\text{hp} - \text{hr}} \times \frac{1.0\ \text{lb CO}}{454\ \text{g CO}} = 2.92\ \frac{\text{lb CO}}{\text{hr}}$$

$$\text{Maximum Annual Emission Rate} = \frac{2.92\ \text{lb CO}}{\text{hour}} \times \frac{200\ \text{hours}}{\text{year}} = 0.29\ \frac{\text{ton CO}}{\text{year}}$$

6.1.1 STEP 1. Identify All Available Control Technologies.

Available controls for CO emissions from diesel (compression ignition) engines include good combustion practices based on engine design, and oxidation catalysts as post combustion CO control systems. Note that the proposed engine will be a certified engine that does not require an oxidation catalyst to meet the performance standard.

6.1.2 STEP 2. Eliminate Technically Infeasible Options.

Good combustion practices based on engine design is technically feasible. While the use of oxidation catalysts as a post combustion control system is a technically feasible control option for diesel engines, oxidation catalysts are not typically employed for emergency fire pumps because of the critical nature of the engine service and the need for the engine to start reliably. Therefore, oxidation catalysts may be eliminated as technically infeasible. However, an oxidation catalyst will also be evaluated for economic feasibility.

6.1.3 STEP 3. Rank the Technically Feasible Control Technologies.

Good combustion practices based on engine design, combined with the limited use nature of this emergency generator, is expected to limit CO emissions to less than 0.29 tons per year. The use of an oxidation catalyst as a post combustion CO control system would be expected to reduce emissions by 90%.

6.1.4 STEP 4. Evaluate the Most Effective Controls.

An oxidation catalyst system for this engine is expected to have a total capital investment of at least $20,000. Based on a 7% interest rate and a project life of 20 years, the capital recovery factor for this investment is 0.0944. Therefore, the annual cost to pay for the capital investment is $1,890 per year. For a CO reduction of 0.26 per year, the cost effectiveness of an oxidation catalyst control system based on ONLY the capital investment would be $7,260 per ton of CO controlled. This is a very high control cost for the use of oxidation catalysts, especially since it is based only on the capital investment cost. The South Coast Air Quality Management District's BACT maximum cost effectiveness value for CO emissions in 2025 was $867 per ton of average cost effectiveness. The control cost effectiveness of an oxidation catalyst for this emergency fire pump would be more than 8 times this value. Therefore, an oxidation catalyst system is not an economically feasible CO control technology for this emergency fire pump.

Please note that the U.S. EPA has also estimated that the cost effectiveness of adding CO, NO_x, and PM controls to stationary diesel engines in the report *Alternative Control Techniques Document: Stationary Diesel Engines*, March 5, 2010 (available at Alternative Control Techniques Document:). In this analysis, EPA estimated that the cost of adding CO, NO_x, and PM controls to a Tier 3 engine rated from 600 – 750 horsepower and operating for 1,000 hours per year at $10,400, $16,100, and $91,700 per ton of CO, NO_x, and PM controlled, respectively. Based on the above costs and this U.S. EPA analysis, the use of an oxidation catalyst is not an economically feasible control option for this emergency fire pump.

6.1.5 STEP 5. Proposed CO BACT Determination.

Based on this analysis, APS has concluded that the use of a diesel engine-driven emergency fire pump which meets the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*, 40 CFR 60, Subpart IIII, combined with limited hours of operation represents the best available control technology (BACT) for the control of CO emissions from this fire pump. Based on this analysis, APS proposes the following limits as BACT:

1. The diesel engine-driven emergency fire pump shall comply with the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* 40 CFR 60, Subpart IIII.
2. The total operation of the fire pump may not exceed 200 hours per year.

6.2 NO_x Control Technology Review.

The diesel engine-driven fire pump will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* under 40 CFR 60, Subpart IIII.. These emission standards include a NO_x emission limit of 3.0 grams per horsepower-hour. This emission standard will ensure that these engines minimize NO_x emissions. NO_x emissions have been calculated based on the design engine rating and the NOx + NMHC performance standard of 3.0 grams per horsepower-hour:

$$\text{Maximum Hourly Emission Rate} = 510 \text{ hp} \times \frac{3.0 \text{ g NOx}}{\text{hp} - \text{hr}} \times \frac{1.0 \text{ lb NOx}}{454 \text{ g NOx}} = 3.37 \frac{\text{lb NOx}}{\text{hr}}$$

$$\text{Maximum Annual Emission Rate} = \frac{3.37 \text{ lb NOx}}{\text{hour}} \times \frac{200 \text{ hours}}{\text{year}} = 0.34 \frac{\text{ton NOx}}{\text{year}}$$

6.2.1 STEP 1. Identify All Available Control Technologies.

Available controls for NO_x emissions from diesel engines include good combustion practices based on engine design, and SCR as post combustion NO_x control systems. Note that the proposed engine will be a certified engine that does not require SCR to meet the performance standard.

6.2.2 STEP 2. Eliminate Technically Infeasible Options.

Good combustion practices based on engine design is a technically feasible control option. The manufacturer does not provide an emergency fire pump equipped with SCR. Therefore, the use of SCR as a post combustion control system is not a technically feasible control option.

6.2.3 STEP 3. Rank the Technically Feasible Control Technologies.

Good combustion practices based on engine design will limit NO_x emissions to 0.34 tons per year.

6.2.4 STEP 4. Evaluate the Most Effective Controls.

Because good combustion practices are the only available control technology, further evaluation is unnecessary. Note that even if SCR were available for this fire pump, the U.S. EPA report *Alternative Control Techniques Document: Stationary Diesel Engines*, March 5, 2010 estimated that the cost of adding NO_x controls to a Tier 3 engine rated from 600 – 750 horsepower and operating for 1,000 hours per year at $16,100 per ton of NO_x controlled. Therefore, even if SCR were available for this fire pump, SCR is not an economically feasible control option for this emergency fire pump.

6.2.5 STEP 5. Proposed NO_x BACT Determination.

Based on this analysis, APS has concluded that the use of a diesel engine-driven emergency fire pump which meets the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*, 40 CFR 60, Subpart IIII, combined with limited hours of operation represents the best available control technology (BACT) for the control of NO_x emissions from this fire pump. Based on this analysis, APS proposes the following limits as BACT:

1. The diesel engine-driven emergency fire pump shall comply with the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* 40 CFR 60, Subpart IIII.
2. The total operation of the fire pump may not exceed 200 hours per year.

6.3 Particulate Matter (PM), PM_{10}, and $PM_{2.5}$ Control Technology Review.

Emissions of particulate matter (PM), including particulate matter with aerodynamic particle sizes less than 10 microns (PM_{10}), and particulate matter with aerodynamic particle sizes less than 2.5 microns ($PM_{2.5}$) from diesel engines result from PM in the combustion air, from ash in the fuel, engine wear, and from products of incomplete combustion. For this analysis, all PM emissions from this emergency fire pump are also assumed to be PM_{10} and $PM_{2.5}$ emissions.

The diesel engine-driven fire pump will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* under 40 CFR 60, Subpart IIII.. These emission standards include a PM emission limit of 0.15 grams per horsepower-hour. This emission standard will ensure that these engines minimize PM emissions. PM emissions have been calculated based on the design engine rating and the PM performance standard of 0.15 grams per horsepower-hour:

$$\text{Maximum Hourly Emission Rate} = 510\ \text{hp} \times \frac{0.15\ \text{g PM}}{\text{hp} - \text{hr}} \times \frac{1.0\ \text{lb PM}}{454\ \text{g PM}} = 0.17\ \frac{\text{lb PM}}{\text{hr}}$$

$$\text{Maximum Annual Emission Rate} = \frac{0.17\ \text{lb PM}}{\text{hour}} \times \frac{200\ \text{hours}}{\text{year}} = 0.02\ \frac{\text{ton PM}}{\text{year}}$$

6.3.1 STEP 1. Identify All Available Control Technologies.

While there are many PM control systems available, the only available controls which have been applied for the control of PM emissions from emergency fire pump diesel (compression ignition) engines is good combustion practices based on engine design. PM traps or catalysts are also available but are generally not used on emergency fire pump engines.

6.3.2 STEP 2. Eliminate Technically Infeasible Options.

The only available controls which have been applied for the control of PM emissions from emergency fire pump diesel engines is good combustion practices based on engine design. PM traps or catalysts are also available but are generally not used on emergency fire pump engines which must start reliably.

6.3.3 STEP 3. Rank the Technically Feasible Control Technologies.

The only available controls which have been applied for the control of PM emissions from natural gas-fired spark ignition engines is good combustion practices based on engine design.

6.3.4 STEP 4. Evaluate the Most Effective Controls.

Because good combustion practices are the only available control technology, further evaluation is unnecessary. Note that even if PM traps or oxidation catalysts were available for this fire pump, the U.S. EPA report *Alternative Control Techniques Document: Stationary Diesel Engines*, March 5, 2010 estimated that the cost of adding PM controls to a Tier 3 engine rated from 600 – 750 horsepower and operating for 1,000 hours per year at $91,700 per ton of PM controlled. Therefore, even if particulate traps or oxidation catalysts were available for this fire pump, these controls are not economically feasible control options for this emergency fire pump which will normally operate much less than 100 hours per year.

6.3.5 STEP 5. Proposed BACT Determination.

Based on this analysis, APS has concluded that the use of a diesel engine-driven emergency fire pump which meets the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*, 40 CFR 60, Subpart IIII, combined with limited hours of operation represents the best available control technology (BACT) for the control of PM, PM_{10}, and $PM_{2.5}$ emissions from this fire pump. Based on this analysis, APS proposes the following limits as BACT:

1. The diesel engine-driven emergency fire pump shall comply with the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* 40 CFR 60, Subpart IIII.
2. The total operation of the fire pump may not exceed 200 hours per year.

6.4 VOC Control Technology Review.

The diesel engine-driven fire pump will be subject to the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* under 40 CFR 60, Subpart IIII. Potential VOC emissions are based on the NMHC + NO_x standard of 3.0 g/hp-hour and assume one-half of the total NMHC + NO_x emissions are VOC emissions. This emission standard will ensure that these engines minimize VOC emissions. VOC emissions have been calculated based on the design engine rating and a VOC emission rate of 1.5 grams per horsepower-hour:

$$\text{Maximum Hourly Emission Rate} = 510\ \text{hp} \times \frac{1.5\ \text{g VOC}}{\text{hp} - \text{hr}} \times \frac{1.0\ \text{lb VOC}}{454\ \text{g VOC}} = 1.69\ \frac{\text{lb VOC}}{\text{hr}}$$

$$\text{Maximum Annual Emission Rate} = \frac{1.69\ \text{lb VOC}}{\text{hour}} \times \frac{200\ \text{hours}}{\text{year}} = 0.17\ \frac{\text{ton VOC}}{\text{year}}$$

6.4.1 STEP 1. Identify All Available Control Technologies.

Available controls for VOC emissions from diesel (compression ignition) engines include good combustion practices based on engine design, and oxidation catalysts as post combustion VOC control systems. Note that the proposed engine will be a certified engine that does not require an oxidation catalyst to meet the NMHC + NO_x emissions performance standard.

6.4.2 STEP 2. Eliminate Technically Infeasible Options.

Good combustion practices based on engine design is technically feasible. While the use of oxidation catalysts as a post combustion control system is a technically feasible control option for diesel engines, oxidation catalysts are not typically employed for emergency fire pumps because of the critical nature of the engine service and the need for the engine to start reliably. Therefore, oxidation catalysts may be eliminated as technically infeasible. However, an oxidation catalyst will also be evaluated for economic feasibility.

6.4.3 STEP 3. Rank the Technically Feasible Control Technologies.

Good combustion practices based on engine design, combined with the limited use nature of this emergency generator, is expected to limit VOC emissions to less than 0.17 tons per year. The use of an oxidation catalyst as a post combustion VOC control system would be expected to reduce emissions by 50%.

6.4.4 STEP 4. Evaluate the Most Effective Controls.

Good combustion practices based on engine design is the only VOC control technology available for this emergency fire pump. In addition, the U.S. EPA has also estimated that the cost effectiveness of adding CO, NO_x, and PM controls to stationary diesel engines in the report *Alternative Control Techniques Document: Stationary Diesel Engines*, March 5, 2010 (available at Alternative Control Techniques

Document:). Based on this U.S. EPA analysis, the use of an oxidation catalyst is not an economically feasible control option for this emergency fire pump.

6.4.5 STEP 5. Proposed VOC BACT Determination.

Based on this analysis, APS has concluded that the use of a diesel engine-driven emergency fire pump which meets the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*, 40 CFR 60, Subpart IIII, combined with limited hours of operation represents the best available control technology (BACT) for the control of VOC emissions from this fire pump. Based on this analysis, APS proposes the following limits as BACT:

1. The diesel engine-driven emergency fire pump shall comply with the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* 40 CFR 60, Subpart IIII.
2. The total operation of the fire pump may not exceed 200 hours per year.

6.5 GHG Emissions Control Technology Review.

The diesel engine driven emergency fire pump will be a small source of GHG emissions. Potential air pollutant emissions for this new fire pump are summarized in Table D7-1 and are based on 200 hours per year of operation. From Table D7-1, potential CO_2 and GHG emissions are 68.5 and 68.8 tons per year, respectively. ***Because CO_2 emissions account for 99.6% of the GHG emissions from this fire pump, this control technology review for GHG emissions will focus on CO_2 emissions.***

6.5.1 STEP 1. Identify All Available Control Technologies.

Available controls for CO_2 emissions from this emergency fire pump include the use of low carbon containing or lower emitting primary fuels, energy efficient processes and technologies, and carbon capture and storage (CCS) as a post combustion control system. Available control technologies for the control of CH_4 and N_2O emissions include good combustion practices, oxidation catalysts, and thermal oxidation.

6.5.2 STEP 2. Eliminate Technically Infeasible Options.

The use of low carbon containing fuels and the use of energy efficient processes are technically feasible CO_2 control options. Note that the design fuel for this fire pump, diesel fuel oil, is a low CO_2 emitting fossil fuel. Good combustion practices including the proper maintenance and tune-up of the engine in accordance with the manufacturer's specifications and good engineering practices is also a technically feasible control option. The use of oxidation catalysts as a post combustion control system for methane (CH_4) emissions is also technically feasible.

With respect to carbon capture and sequestration (CCS), as noted in the GHG analyses for the simple and combined cycle CTs, for CCS to be technically feasible, all three of the CCS steps must be technically feasible. The technical feasibility of CCS depends on the availability of appropriate geological sequestration sites in the vicinity of the plant. And as noted, the closest possible geologic carbon sequestration sites are at least 200 miles from the Desert Sun Power Plant, and these closest sites have not been verified as either suitable or available. In any case, a CO_2 pipeline would be required which would stretch for hundreds of miles, and access to an appropriate sequestration site would still be required.

CCS is also technically infeasible for this emergency fire pump because the emergency use nature of this engine precludes the use of a CCS system which must operate in a steady-state or near steady-state fashion. Based on these facts, CCS is not a technically feasible control technology for the control of GHG emissions from the emergency fire pump.

6.5.3 STEP 3. Rank the Technically Feasible Control Technologies.

For CO_2 emissions, the use of diesel fuel is the lowest technically feasible carbon containing fuel for this emergency engine and is therefore the top ranked level of control for low carbon containing fuels. Good combustion practices is also a technically feasible control technology for this heater. This combination of controls will limit GHG emissions to no more than 164 lb/mmBtu.

6.5.4 STEP 4. Evaluate the Most Effective Controls.

The use of a low carbon containing technically feasible fuel – diesel fuel – combined with good combustion practices are appropriate technologies for this emergency fire pump and will not have adverse environmental or economic impacts. Therefore, these controls are an appropriate basis as BACT for the control of GHG emissions.

In addition, the U.S. EPA has also estimated that the cost effectiveness of adding CO, NO_x, and PM controls to stationary diesel engines in the report *Alternative Control Techniques Document: Stationary Diesel Engines,* March 5, 2010 (available at Alternative Control Techniques Document:). Based on this U.S. EPA analysis, the use of an oxidation catalyst is not an economically feasible control option for this emergency fire pump.

6.5.5 STEP 5. Proposed GHG BACT Determination.

Based on this analysis, APS has concluded that the use of a diesel engine-driven emergency fire pump which meets the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines,* 40 CFR 60, Subpart IIII, combined with limited hours of operation represents the best available control technology (BACT) for the control of GHG emissions from this fire pump. Based on this analysis, APS proposes the following limits as BACT:

1. The diesel engine-driven emergency fire pump shall comply with the *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* 40 CFR 60, Subpart IIII.
2. The total operation of the fire pump may not exceed 200 hours per year.

Chapter 7. Natural Gas Piping Systems GHG Control Technology Review.

7.1 Greenhouse Gas (GHG) Emissions Control Technology Review.

The Prevention of Significant Deterioration (PSD) program in 40 CFR §52.21 includes methane (CH_4) as a regulated GHG substance or pollutant. Natural gas piping components including valves, connection points, pressure relief valves, pump seals, compressor seals, and sampling connections can leak and result in fugitive natural gas emissions. Since natural gas consists of from 70 to almost 100% methane, leaks in the natural gas piping can result in methane emissions, and methane is a regulated greenhouse gas.

The Mandatory Greenhouse Gas Reporting Rules in 40 CFR Part 98, Subpart W include methods for estimating GHG emissions from petroleum and natural gas systems. Table 3-4 summarizes the estimated fugitive methane emissions and the equivalent GHG emissions, expressed as CO_2e, which are expected to result from a properly operated and maintained natural gas piping system for new CTs.

7.1.1 STEP 1. Identify All Potential Control Technologies.

The following technologies are available to control fugitive methane emissions from natural gas piping systems.

1. Leakless technology components,
2. Leak detection and repair (LDAR) program,
3. Alternative monitoring using remote sensing technology, and
4. Audio/visual/olfactory (AVO) monitoring program.

7.1.2 STEP 2. Identify Technically Feasible Control Technologies.

"Leakless" technologies such as bellows or seal valves can reduce fugitive natural gas emissions by eliminating valve gasket and flange leak paths. Other leak paths nevertheless do exist so that this technology does not eliminate fugitive emissions. Leakless technology components are used for highly toxic and hazardous materials but are not normally used in natural gas piping systems because of the high cost for these components and the difficulty in maintaining and repairing these components. For example, if a welded or threaded and seal welded bonnet joint valve fails, the failed component cannot be repaired without a unit shutdown, and the repair may result in additional maintenance related natural gas venting which can reduce its overall control effectiveness. Seal valves have other limitations which limit their use, including cycle life, pressure retention capability, and size limitations. Because these components are not a standard used in natural gas piping systems, the use of leakless valves is not considered a technically feasible control option for the CT Project natural gas piping systems.

Leak detection and repair (LDAR) programs, alternative monitoring using remote sensing technology, and audio/visual/olfactory (AVO) monitoring programs are technically feasible control options.

7.1.3 STEP 3. Rank the Technically Feasible Control Technologies.

Leak detection and repair (LDAR) programs using instrument monitoring are effective for identifying leaking components and is an accepted practice for limiting VOC emissions from gas processing and chemical plants. Quarterly monitoring with an instrument and a leak definition of 500 ppm is considered to have a control efficiency of 97% for valves, flanges, and connectors. Remote sensing using infrared imaging is also effective in detecting leaks, especially for components in difficult to monitor areas and is considered to be equivalent to LDAR.

Audio/visual/olfactory (AVO) monitoring is also an effective monitoring method for odorous and low vapor pressure compounds such as natural gas, especially because the observations can be substantially more frequent than for LDAR. Pipeline natural gas is purposely odorized with mercaptan for safety. As a result, natural gas leaks have a discernible odor. Larger leaks can be detected by sound and sight, either directly or as a secondary indicator such as condensation around a leaking source due to the adiabatic cooling effect of the expanding gas as it leaves the leaking component. Thus, observations for leaking valves or components can be made when plant personnel make routine walk-downs of the plant. As a result, AVO observation is an effective method for identifying and correcting leaks in natural gas systems, especially larger leaks that can result in increased emissions and potentially hazardous conditions. The Texas Commission on Environmental Quality (TCEQ) also assigns a 97% control effectiveness for AVO for odorous and low vapor pressure compounds such as natural gas.

7.1.4 STEP 4. Evaluate the Most Effective Controls.

The use of audio/visual/olfactory (AVO) monitoring is an effective monitoring method for the control of fugitive methane emissions from the natural gas piping systems. The proposed project will also utilize high quality components and materials of construction that are compatible with the service in which they are employed. This is the highest level of control available for the control of methane emissions from the piping systems. Therefore, no further evaluation is necessary.

7.1.5 STEP 5. Proposed GHG BACT Determination.

Based on this analysis, APS has concluded that the use of audio/visual/olfactory (AVO) monitoring represents the Best Available Control Technology (BACT) for the control of fugitive methane (greenhouse gas) emissions from the natural gas piping systems. APS proposes the following conditions as BACT:

1. The permittee shall implement an auditory/visual/olfactory (AVO) monitoring program for detecting leaks in the Project natural gas piping components.
2. AVO monitoring shall be performed in accordance with a written monitoring program.

Chapter 8. SF_6 Insulated Electrical Equipment Control Technology Review.

8.1 Greenhouse Gas (GHG) Emissions Control Technology Review.

Under the Prevention of Significant Deterioration (PSD) program in 40 CFR §52.21, sulfur hexafluoride (SF_6), Chemical Abstract Service (CAS) No. 2551-62-4, is also listed as regulated GHG. The new Project will include circuit breakers and switch gear for the CTs which will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable, inert, and non-toxic gas. SF_6 has a very stable molecular structure and has a very high ionization energy which makes it an excellent electrical insulator. The gas is used for electrical insulation, arc suppression, and current interruption in high-voltage electrical equipment.

The electrical equipment containing SF_6 is designed not to leak, because if too much gas leaks out, the equipment may not operate correctly and could become unsafe. State-of-the-art circuit breakers are gas-tight and are designed to achieve a leak rate of less than or equal to 0.5% per year (by weight). This is the same leak rate from the U.S. EPA report, *SF_6 Leak Rates from High Voltage Circuit Breakers - EPA Investigates Potential Greenhouse Gas Emission Source*, J. Blackman, Program Manager, EPA, and M. Avery, ICF Consulting, and Z. Taylor, ICF Consulting. This is also the International Electrotechnical Commission (IEC) maximum leak rate standard.

Table 3-5 summarizes the potential SF_6 emissions for the planned equipment based on this leak rate. Note that these emissions represent less than 0.03% of the total GHG emissions from the proposed Project.

8.1.1 STEP 1. Identify All Potential Control Technologies.

The following technologies are available to control fugitive SF_6 emissions from electrical equipment:

1. State-of-the-art enclosed-pressure SF_6 technology with leak detection.
2. Use of a non-GHG emission dielectric material in the breakers.

8.1.2 STEP 2. Identify Technically Feasible Control Technologies.

State-of-the-art enclosed-pressure SF_6 technology with leak detection is an available technology used to limit fugitive SF_6 emissions.

There are no available alternative insulating material or substances as available alternatives. In the report *SF_6 Emission Reduction Partnership for Electric Power Systems, 2014 Annual Report*, U.S. EPA, March 2015, (http://www.epa.gov/electricpower-sf6/documents/SF6_AnnRep_2015_v9.pdf), EPA states "Because there is no clear alternative to SF_6, Partners reduce their greenhouse gas emissions through implementing emission reduction strategies such as detecting, repairing, and/or replacing problem equipment, as well as educating gas handlers on proper handling techniques of SF_6 gas during equipment installation, servicing, and disposal." Therefore, the use of alternative substances as dielectric materials is not considered a technically feasible control option for these circuit breakers.

8.1.3 STEP 3. Rank the Technically Feasible Control Technologies.

The use of state-of-the-art enclosed SF_6 technology with leak detection is the highest ranked technically feasible control technology to limit fugitive SF_6 emissions from the proposed electrical equipment.

8.1.4 STEP 4. Evaluate the Most Effective Controls.

The use of state-of-the-art enclosed SF_6 technology with leak detection for the control of SF_6 emissions from the proposed electrical equipment is the highest level of control available for the control of SF_6 emissions. Therefore, further evaluation is unnecessary.

8.1.5 STEP 5. Proposed GHG BACT Determination.

Based on this analysis, APS has concluded that the use of state-of-the-art enclosed SF_6 technology with leak detection represents the Best Available Control technology (BACT) for the control of fugitive SF_6 emissions from the proposed electrical equipment. APS proposes the following conditions as BACT:

1. The Permittee shall install, operate, and maintain enclosed-pressure SF_6 circuit breakers with a maximum design annual leakage rate of 0.5% by weight.
2. The new circuit breakers shall be equipped with a leak detection system.
3. The permittee shall maintain records of the date that any leak is detected in a circuit breaker and the leak amount in weight percent.
4. The permittee shall maintain records of the date and the amount of SF_6 added to the circuit breakers.

Appendix E.

Acid Rain Permit Application.

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 12/31/2021

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☑ new ☐ revised ☐ for ARP permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Desert Sun Power Plant	AZ	

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
CC1	Yes
CC2	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

Desert Sun Power Plant Facility (Source) Name (from STEP 1)

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
- (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
- (ii) Submit in a timely manner 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;

(2) The owners and operators of each affected source and each affected unit at the source shall:
- (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
- (ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
- (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (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 affected units at the source; and
- (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
- (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
- (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Desert Sun Power Plant
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Excess Emissions Requirements

(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 part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
  (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
  (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall 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:
  (i) 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;
  (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
  (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
  (iv) 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.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Desert Sun Power Plant
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4

Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Peter Candelaria	
Signature [signature]	Date 5/13/2026

Instructions for the Acid Rain Program Permit Application

The Acid Rain Program requires the designated representative to submit an Acid Rain permit application for each source with an affected unit. A complete Certificate of Representation must be received by EPA before the permit application is submitted to the Title V permitting authority. A complete Acid Rain permit application, once submitted, is binding on the owners and operators of the affected source and is enforceable in the absence of a permit until the Title V permitting authority either issues a permit to the source or disapproves the application.

Please type or print. If assistance is needed, contact the Title V permitting authority.

STEP 1 A Plant Code is a 4 or 5 digit number assigned by the Department of Energy's (DOE) Energy Information Administration (EIA) to facilities that generate electricity. For older facilities, "Plant Code" is synonymous with "ORISPL" and "Facility" codes. If the facility generates electricity but no Plant Code has been assigned, or if there is uncertainty regarding what the Plant Code is, send an email to the EIA. The email address is EIA-860@eia.gov.

STEP 2 In column "a," identify each unit at the facility by providing the appropriate unit identification number, consistent with the identifiers used in the Certificate of Representation and with submissions made to DOE and/or EIA. Do not list duct burners. For new units without identification numbers, owners and operators must assign identifiers consistent with EIA and DOE requirements. Each Acid Rain Program submission that includes the unit identification number(s) (e.g., Acid Rain permit applications, monitoring plans, quarterly reports, etc.) should reference those unit identification numbers in exactly the same way that they are referenced on the Certificate of Representation.

Submission Deadlines

For new units, an initial Acid Rain permit application must be submitted to the Title V permitting authority 24 months before the date the unit commences operation. Acid Rain permit renewal applications must be submitted at least 6 months in advance of the expiration of the acid rain portion of a Title V permit, or such longer time as provided for under the Title V permitting authority's operating permits regulation.

Submission Instructions

Submit this form to the appropriate Title V permitting authority. If you have questions regarding this form, contact your local, State, or EPA Regional Acid Rain contact, or call EPA's Clean Air Markets Hotline at (202) 343-9620.

Paperwork Burden Estimate

The public reporting and record keeping burden for this collection of information is estimated to average 8 hours per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. **Do not send the completed form to this address.**

STEP 3, Cont'd.

Excess Emissions Requirements

(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 part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
   (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
   (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

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   (i) 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;
   (ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
   (iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
   (iv) 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.
(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
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(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.