DRAFT TECHNICAL SUPPORT DOCUMENT

ADEQ
Arizona Department of Environmental Quality
Janice K. Brewer, Governor
Henry R. Darwin, Director

**TECHNICAL REVIEW AND EVALUATION
OF APPLICATION FOR
AIR QUALITY PERMIT NO. 58787**

Bowie Power Station, LLC

I. INTRODUCTION

This Air Quality Class I Permit is issued to Bowie Power Station, LLC, the Permittee, for the construction and operation of a power generating plant, located approximately two miles north of the unincorporated community of Bowie, in Cochise County, Arizona.

A. Company Information

1. Facility Name: Bowie Power Station

2. Facility Location: Central Avenue and Rosewood Road
Section 28, T12S, R28E
Gila and Salt River Base and Meridian, Cochise County

3. Mailing Address: 3610 N. 44th St., Suite 250, Phoenix, AZ 85018

B. Background

The planned Bowie Power Station will be a natural gas-fired, combined cycle power plant with a total rating of 1,050 Megawatts (MW) (nominal). This Class I Permit covers Phase 1, which is the first of two identical construction phases. Phase 1 comprises two combustion turbine generators, two heat recovery steam generators with duct firing, one steam turbine generator, and one mechanical draft nine-cell cooling tower.

Bowie Power Station is a major source because the potential emission rates of the following regulated NSR pollutants are greater than 100 tons per year: NO_X, CO, and greenhouse gases (GHG). Bowie Power Station is also subject to the Acid Rain Program of the Clean Air Act. This permit is issued in accordance with Titles I and V of the Clean Air Act, and Title 49, Chapter 3 of the Arizona Revised Statutes (A.R.S.).

The application was received by ADEQ on September 24, 2013.

Bowie Power Station, LLC was initially issued a Class I operating permit on March 26, 2003. This original permit was terminated on September 26, 2004, upon expiration of the 18 month construction timeframe under Arizona Administrative Code (A.A.C.) R18-2-402.D. The applicant subsequently submitted a second PSD permit application and a Class I operating permit was issued on March 14, 2006. That permit was also terminated upon expiration of the 18 month construction timeframe.

C. Attainment Classification

The proposed facility location in Cochise County is classified at 40 CFR § 81.303 as attainment or unclassifiable for all criteria pollutants: particulate matter less than 10 microns in diameter (PM10), particulate matter less than 2.5 microns in diameter (PM2.5), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), lead (Pb), and ozone (O_3).

II. PROCESS DESCRIPTION

A. Process Equipment

The proposed final Air Quality Class I Permit is for Phase 1 of the Bowie Power Station project, comprising two General Electric (GE) Frame 7FA, Model 4, combustion turbine generators (CTG); two heat recovery steam generators (HRSG) with duct firing; one steam turbine generator (STG), and one mechanical draft nine-cell cooling tower. The nominal electric generating capacity of the facility is 525 MW. Auxiliary equipment include a natural gas-fired boiler producing 41,500 pounds per hour (lb/hr) of steam at a pressure of 150 pounds per square inch gauge (psig); a diesel-fired emergency fire pump with a nominal capacity of 260 horsepower (hp); two evaporation ponds; and five, 345-kilovolt (kV) circuit breakers.

With the exception of the diesel-fueled fire pump engine, the only fuel used at the facility will be pipeline quality natural gas; there are no provisions for back-up fuels for the CTG/HRSG units or the auxiliary boiler.

The project is classified as Standard Industrial Classification Code 4911 and North American Industrial Classification System 221112, Fossil-Fuel Electric Power Generation.

B. Air Pollution Control Equipment

Air pollution control equipment for the CTG/HRSG units include dry low-NO_X (DLN) combustors and selective catalytic reduction (SCR) for the control of nitrogen oxides (NO_X), and oxidation catalyst for the control of carbon monoxide (CO), volatile organic compounds (VOC), and hazardous air pollutants (HAPs). The auxiliary boiler will be equipped with ultra-low-NO_X burners and flue gas recirculation and the mechanical draft cooling tower will be equipped with high-efficiency drift eliminators.

III. LEARNING SITES EVALUATION

In accordance with ADEQ's Environmental Permits and Approvals Near Learning Sites Policy, the Department conducted an evaluation to determine if any nearby learning sites would be adversely impacted by the facility. Learning sites consist of all existing public schools, charter schools and private schools at the K-12 level, and all planned sites for schools approved by the Arizona School Facilities Board. The learning sites policy was established to ensure that the protection of children at learning sites is considered before a permit approval is issued by ADEQ.

Upon review of ADEQ's database, it was determined that there are no learning sites within two miles of the proposed facility location.

IV. EMISSIONS

Table 1: Potential Emissions

Pollutant	Emissions (tons per year)
PM	68
PM_{10}	66
$PM_{2.5}$	63
NO_x	139
CO	162
SO_2	30
VOC	31
GHG (mass)	1,752,000
GHG (expressed as CO_2e)	1,754,000
HAPs	7

V. APPLICABLE REGULATIONS

A. Prevention of Significant Deterioration (PSD)

As discussed in Section I.B herein, the proposed Bowie Power Station is a major source with the potential to emit several regulated NSR pollutants in excess of 100 tpy. Therefore, permitting of the facility is subject to PSD review requirements set forth at A.A.C. R18-2, Article 4, as summarized below.

1. Best Available Control Technology (BACT)

Pursuant to A.A.C. R18-2-406.A.1 and -406.A.4, and 40 CFR § 52.21(j)(2) with respect to GHG emissions, BACT is required for each regulated NSR pollutant for which the facility's potential to emit is significant. For this project, BACT applies with respect to NO_X, CO, PM, PM10, PM2.5, and GHG. The determination of BACT is discussed in detail in Section VI herein.

2. Air Quality Impact Analysis

Pursuant to A.A.C. R18-2-406.A.5 and -406.A.6, the Permittee is required to submit an analysis of air quality impacts demonstrating that the allowable emissions increases would not cause or contribute to a violation of a National Ambient Air Quality Standard (NAAQS) and would not cause or contribute significant deterioration of air quality. The air quality impact analysis is discussed in detail in Section XI herein.

3. Air Quality Monitoring Requirements

Pursuant to A.A.C. R18-2-407.A through -407.H and -409, the Permittee is required to submit an analysis of ambient air quality in the area affected by the facility's emissions. This analysis is discussed in Section XI herein.

4. Additional Impacts Analysis

Pursuant to A.A.C. R18-2-407.I, the Permittee is required to submit analyses of impairment to visibility, soils, and vegetation that would occur as a result of the facility, including general commercial, residential, industrial, and other growth associated with the facility. This analysis is discussed in Section XI herein.

5. Class I Impacts Analysis

Pursuant to A.A.C. R18-2-410, the Permittee is required to submit an analysis of anticipated impacts of the proposed facility on visibility in any Class I areas which may be affected by its emissions. This analysis is discussed in Section XI herein.

B. Other Applicable Requirements

For each permitted emissions unit, Table 2 displays the applicable requirements derived from authorities other than the PSD regulation along with a brief explanation of why the requirements are applicable.

Table 2: Verification of Applicable Regulations

Unit	**Control Device**	**Rule**	**Verification**
Combined Cycle Systems	SCR	NSPS Subpart KKKK 40 CFR § 60.4305(a)	The entire combined cycle system, including duct burners, is the affected facility.
Combined Cycle Systems	SCR	NSPS Subpart KKKK 40 CFR §§ 60.4333, 60.4335, 60.4345, 60.4345, 60.4350, 60.4365, 60.4400, 60.4415	These standards are applicable to gas-fired facilities.
Auxiliary Boiler	None	NSPS Subpart Dc 40 CFR §§ 60.48c(a), 60.48c(g)	These standards are applicable to gas-fired facilities.

Table 2: Verification of Applicable Regulations

Unit	Control Device	Rule	Verification
Diesel-Fired Emergency Fire Pump	None	NSPS Subpart IIII 40 CFR §§ 60.4205, 60.4207, 60.4209, 60.4211	These standards are applicable to emergency fire pumps.
Ammonia Storage	None	40 CFR § 68.130	This rule would require a Risk Management Plan if a threshold quantity of ammonia were stored on site.
Fugitive dust sources	Water Trucks Dust Suppressants	A.A.C. R18-2 Article 6 A.A.C. R18-2-702	These standards are applicable to all fugitive dust sources at the facility.
Abrasive Blasting	Wet blasting; Dust collecting equipment; Other approved methods	A.A.C. R-18-2-702 A.A.C. R-18-2-726	These standards are applicable to any abrasive blasting operation.
Spray Painting	Enclosures	A.A.C. R18-2-702 A.A.C. R-18-2-727	This standard is applicable to any spray painting operation.
Demolition/renovation operations	N/A	A.A.C. R18-2-1101.A.8	This standard is applicable to any asbestos related demolition or renovation operations.
Mobile sources	None	A.A.C. R18-2-801	These are applicable to off-road mobile sources, which either move while emitting air pollutants or are frequently moved during the course of their utilization.

VI. BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

As discussed in Section V herein, construction of the proposed Bowie Power Station is subject to preconstruction PSD review, including the BACT requirement under A.A.C. R18-2-406.A.1, with respect to the following regulated NSR pollutants: NO_X, CO, PM, PM10, PM2.5, and GHG.

A. General

The term “best available control technology” is defined in the ADEQ regulations as follows:

> “Best available control technology” (BACT) means an emission limitation, including a visible emissions standard, based on the maximum

> degree of reduction for each air regulated NSR pollutant which would be emitted from any proposed major source or major modification, taking into account energy, environmental, and economic impact and other costs, determined by the Director in accordance with R18-2-406(A)(4) to be achievable for such source or modification. (A.A.C. R18-2-101.21)

The regulations also include the following general requirements for the determination of BACT:

> BACT shall be determined on a case-by-case basis and may constitute application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment, clean fuels, or innovative fuel combustion techniques, for control of such pollutant. In no event shall such application of BACT result in emissions of any pollutant, which would exceed the emissions allowed by any applicable new source performance standard or national emission standard for hazardous air pollutants under Articles 9 and 11 of this Chapter or by the applicable implementation plan. If the Director 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. (A.A.C. R18-2-406.A.4)

The U.S. EPA's interpretive policies relating to BACT analyses are set forth in several informal guidance documents. Most notable among these are the following:

- "Guidelines for Determining Best Available Control Technology (BACT)," December 1978.
- "Prevention of Significant Deterioration Workshop Manual," October 1980.
- "New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting." Draft. October 1990.

The Department generally uses what is termed a "top-down" procedure when making BACT determinations. This procedure is designed to ensure that each determination is made consistent with the two core criteria for BACT: consideration of the most stringent control technologies available, and a reasoned justification, considering energy, environmental and economic impacts and other costs, of any decision to require less than the maximum degree of reduction in emissions.

The framework for the top-down BACT analysis procedure used by the Department comprises five key steps, as discussed in detail below. The five-step procedure mirrors the analytical framework set forth in the draft 1990 guidance document. However, it should be noted that the Department does not necessarily adhere to the prescriptive process described in the draft 1990 guidance document. Strict adherence to the detailed top-down BACT analysis process described in that draft document would unnecessarily restrict the Department's judgment and discretion in weighing various factors before making case-by-case BACT determinations. Rather, as outlined in the 1978 and 1980 guidance documents, the Department has broad flexibility in applying its judgment and discretion in making these determinations.

Step 1 - Identify all control options. The process is performed on a unit-by-unit and pollutant-by-pollutant basis and begins with the identification of available control technologies and techniques. For BACT purposes, "available" control options are those technologies and techniques, or combinations of technologies and techniques, with a practical potential for application to the subject emissions units and pollutants. These may include fuel cleaning or treatment, inherently lower polluting processes, and end of pipe control devices. All identified control options that are not inconsistent with the fundamental purpose and basic design of the proposed facility are listed in this step. (Because the definition of BACT includes the phrase, "achievable for such source or modification," ADEQ interprets the BACT requirement as not providing for consideration of any emission limit that would necessitate redefinition of the fundamental purpose or basic design of the proposed facility. For the Bowie Power Station, this includes the facility design described in Section II.A and the flexibility to operate up to 8,760 hours per year, constrained only by certain operational limits proposed by the applicant, with no minimum number of operating hours.) Those control options that are identified as being technically infeasible or as having unreasonable energy, economic or environmental impacts or other unacceptable costs are eliminated in subsequent steps.

Step 2 - Eliminate technically infeasible control options. In this step, the technical feasibility of identified control options is evaluated with respect to source specific factors. Technically feasible control options are those that have been demonstrated to function efficiently on identical or similar processes. In general, if a control option has been demonstrated to function efficiently on the same type of emissions unit, or another unit with similar exhaust streams, the control option is presumed to be technically feasible. For presumably technically feasible control options, demonstrations of technical infeasibility must show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the control option from being employed successfully on the subject emissions unit. Technical feasibility need not be addressed for control options that are less effective than the control option proposed as BACT by the permit applicant.

Step 3 - Characterize control effectiveness of technically feasible control options. For each control option that is not eliminated in Step 2, the overall control effectiveness for the pollutant under review is characterized. The control option with the highest overall effectiveness is the "top" control option. If the top control option is proposed by the permit applicant as BACT, no evaluation is required under Step 4, and the procedure moves to Step 5. Otherwise, the top control option and other identified control options that are more effective than that proposed by the permit applicant must be evaluated in Step 4. A control option that can be designed and operated at two or more levels of control effectiveness may be presented and evaluated as two or more distinct control options (i.e., an option for each control effectiveness level).

Step 4 - Evaluate more effective control options. If any identified and technically feasible control options are more effective than that proposed by the permit applicant as BACT, rejection of those more effective control options must be justified based on the evaluation conducted in this step. For each control option that is more effective than the option ultimately selected as BACT, the rationale for rejection must be documented for the public record. Energy, environmental, and economic impacts and other costs of the more effective control options, including both beneficial and adverse (i.e., positive and negative) impacts, are listed and considered.

Step 5 - Establish BACT. Finally, the most effective control technology not rejected in Step 4 is proposed as BACT. To complete the BACT process, an enforceable emission limit representing BACT must be included in the PSD permit. This emission limit must be enforceable as a practical matter. In order for the emission limit to be enforceable as a practical matter, in the case of a numerical emission limitation, the permit must specify a reasonable compliance averaging time, consistent with established reference methods. The permit must also include compliance verification procedures (i.e., monitoring requirements) designed to show compliance or non-compliance on a time period consistent with the applicable emission limit.

The applicant included proposed BACT determinations and supporting information in its permit application, and ADEQ relied heavily on this information in making the proposed BACT determinations. Other materials considered by ADEQ in identifying and evaluating available control options include the following:

- Entries in the RACT/BACT/LAER Clearinghouse (RBLC) maintained by the U.S. EPA. This database is the most comprehensive and up-to-date listing of control technology determinations available.
- Information provided by pollution control equipment vendors.
- Information provided by industry representatives and by other State permitting authorities. This information is particularly valuable in clarifying or updating control technology information that has not yet been entered into the RACT/BACT/LAER Clearinghouse.

ADEQ's BACT evaluations and proposed BACT determinations for each emissions unit at the proposed Bowie Power Station emitting NO_X, CO, PM, PM10, PM2.5, or GHG are discussed in the following subsections.

B. Combined Cycle Systems

The applicant has proposed that each Combined Cycle System (*i.e.*, each pair of CTG/HRSG units) will be equipped with DLN combustors and an SCR system to control NO_X emissions and oxidation catalyst to control CO emissions. Emissions of particulate matter and GHG will be minimized through inherent design elements such as fuel selection and state-of-the-art electric generating equipment.

1. Particulate Matter (PM/PM10/PM2.5)

The emission limits proposed by the applicant are 8.5 lb/hr during periods with duct firing and 6.5 lb/hr during periods without duct firing based on the achievable performance with the design elements inherent in the proposed project.

There are no known applications of add-on controls for the purpose of controlling particulate matter emissions from natural gas-fired units and no evidence that such controls would result in quantifiable emission reductions. Moreover, even if any add-on controls were technically feasible for further reduction of particulate matter emissions, the resultant economic costs and other adverse effects, such as loss of efficiency due to increased pressure drop, would obviously outweigh the achievable emission reduction.

In the permit application submitted in September 2013, the applicant presented a tabulation of recently established particulate matter emission limits for comparable natural gas-fired combined cycle systems. This table supports the applicant's contention that 8.5 lb/hr represents BACT for the proposed Combined Cycle Systems. In order to ensure the BACT determination is made using the most current information, ADEQ identified and reviewed additional permits, as shown in Table 4, including permits issued within the past eight months.

Table 4. Combined Cycle System Particulate Matter BACT Limits

Facility	Permitting Authority	PM10 Limit
Scattergood Generating Station	South Coast (Calif.) AQMD	10 lb/hr (approximately 0.005 lb/MMBtu HHV at maximum firing rate)
Ninemile Point Plant	Louisiana DEQ	33.16 lb/hr during gas firing, 36.37 lb/hr during oil firing (approximately 0.015 – 0.016 lb/MMBtu HHV at maximum firing rate)
FGE Texas	Texas CEQ	16.4 lb/hr (approximately 0.006 lb/MMBtu HHV at maximum firing rate)
La Paloma Energy Center	Texas CEQ	24.1 lb/hr (approximately 0.01 lb/MMBtu HHV at maximum firing rate)
Pioneer Valley Energy Center	U.S. EPA	0.0040 lb/MMBtu during gas firing, 0.014 lb/MMBtu during oil firing (permit does not specify HHV or LHV basis)
Avenal Power Center	U.S. EPA	11.78 lb/hr (approximately 0.05 lb/MMBtu HHV at maximum firing rate)

ADEQ has concluded that the limits proposed by the applicant represent BACT; no more stringent limit has been demonstrated to be achievable for these Combined Cycle Systems.

2. Nitrogen Oxides (NO_X)

a. Normal Operations

The NO_X emission limit proposed by the applicant for all periods other than startup, shutdown, and tuning of the Combined Cycle Systems is 2.0 ppmvd, corrected to 15% O_2, based on a one-hour average. This proposed limit is based on the achievable performance using DLN combustors and SCR.

ADEQ has reviewed the information provided by the applicant and concurs with the proposed determination that there is no demonstrated control option more effective than the combination of DLN combustors and SCR. In particular, ADEQ has concluded there are insufficient data to support a conclusion that either K-Lean™ or EMx™ technology would provide greater levels of NO_X emission reduction from the proposed Combined Cycle Systems. The adverse impacts of applying SCR, including capital and operating costs, ammonia emissions, and loss of efficiency due to pressure drop across the SCR catalyst, do not warrant rejection of this highly effective NO_X emission control technology.

In the permit application submitted in September 2013, the applicant presented a tabulation of recently established NO_X emission limits for comparable natural gas-fired combined cycle systems. This table supports the applicant's contention that 2.0 ppmvd, corrected to 15% O_2, based on a one-hour average, represents BACT for the proposed Combined Cycle Systems. In order to ensure the BACT determination is made using the most current information, ADEQ identified and reviewed additional permits, as shown in Table 5, including permits issued within the past eight months.

Table 5. Combined Cycle System NO_X BACT Limits

Facility	Permitting Authority	Limit
Scattergood Generating Station	South Coast (Calif.) AQMD	2 ppmvd, corrected to 15 percent O_2, 1-hr basis
FGE Texas	Texas CEQ	2.0 ppmvd, corrected to 15 percent O_2, 24-hr basis
La Paloma Energy Center	Texas CEQ	2.0 ppmvd, corrected to 15 percent O_2, 24-hr basis
Pioneer Valley Energy Center	U.S. EPA	2.0 ppmvd during gas firing, 5.0 ppmvd during oil firing, both corrected to 15 percent O_2, 1-hr basis
Avenal Power Center	U.S. EPA	2.0 ppmvd, corrected to 15 percent O_2, 1-hr basis

ADEQ has concluded that the limit proposed by the applicant represents BACT; no more stringent limit has been demonstrated to be achievable for these Combined Cycle Systems during periods of normal operation.

The proposed NO_X BACT limit of 2.0 ppmvd, corrected to 15% O_2, is not achievable during periods of startup, shutdown, and tuning because neither the DLN combustors nor the SCR function effectively during these periods. Thus, an exemption from this limit will be provided for these periods.

b. Periods of Startup, Shutdown, and Tuning

The NO_X emission limits proposed by the applicant for periods of startup, shutdown, and tuning of the Combined Cycle Systems are as follows. These proposed limits are based on the achievable performance using fast start technology from Kiewit Power Engineers Co. in conjunction with GE Frame 7FA, Model 4, combustion turbines.

(1) 50.7 lb per "hot" startup event, which is a startup event after the unit has been non-operational for a period of less than 8 hours;

(2) 78.9 lb per "warm" startup event, which are startup events after the unit has been non-operational for at least 8 but less than 72 hours;

(3) 78.9 lb per "cold" startup event, which are startup events after the unit has been non-operational for at least 72 hours;

(4) 78.9 lb/hr during tuning periods, which are periods during which the turbine is tested at various incremental loads and during which the NO_X or CO emission limits are not met; and

(5) 16.4 lb per shutdown event.

In conjunction with these emission limits, the applicant has proposed the following two operational limits:

(1) The Permittee shall not cause, allow, or permit the cumulative duration of startup and tuning events at a Combined Cycle System to exceed 325 hours per rolling 12-month period.

(2) The Permittee shall not cause, allow, or permit the cumulative duration of shutdown events at a Combined Cycle System to exceed 91.25 hours per rolling 12-month period.

ADEQ has reviewed the information provided by the applicant and concurs with the proposed determination that there is no demonstrated control option more effective than the fast start technology from Kiewit Power Engineers Co. The limits proposed by the applicant represent BACT; no more stringent limits have been demonstrated to be achievable for these Combined Cycle Systems.

c. Ammonia Slip

As noted above, operation of SCR systems results in undesired emissions of unreacted ammonia. Ammonia is not a regulated NSR pollutant and is not regulated as a precursor to particulate matter, but it has the potential to contribute to ambient concentrations of particulate matter due to atmospheric reactions. Excessive ammonia emissions are an indication of SCR operation not in accordance with good air pollution control practice; thus, ADEQ and other PSD permitting authorities typically impose ammonia emission limits in order to ensure diligent operation of SCR systems and minimize the adverse environmental impacts of operation of these systems.

The applicant estimated ammonia concentration in exhaust gases from the SCR system to be 5.0 ppmvd, corrected to 15% O_2. This concentration is included as an emission limit in the proposed final Class I permit.

3. Carbon Monoxide (CO)

a. Normal Operations

The CO emission limit proposed by the applicant for all periods other than startup, shutdown, and tuning of the Combined Cycle Systems is 2.0 ppmvd, corrected to 15% O_2, based on a one-hour average. This proposed limit is based on the achievable performance using oxidation catalyst.

ADEQ has reviewed the information provided by the applicant and concurs with the proposed determination that there is no demonstrated control option more effective than oxidation catalyst. In particular, ADEQ has concluded there are insufficient data to support a conclusion that either K-Lean™ or EMx™ technology would provide greater levels of CO emission reduction from the proposed Combined Cycle Systems. The adverse impacts of applying oxidation catalyst, including capital and operating costs, increased emissions of sulfuric acid mist, and loss of efficiency due to pressure drop across the catalyst, do not warrant rejection of this highly effective CO emission control technology.

In the permit application submitted in September 2013, the applicant presented a tabulation of recently established CO emission limits for comparable natural gas-fired combined cycle systems. This table supports the applicant's contention that 2.0 ppmvd, corrected to 15% O_2, based on a one-hour average, represents BACT for the proposed Combined Cycle Systems. In order to ensure the BACT determination is made using the most current information, ADEQ identified and reviewed additional permits, as shown in Table 6, including permits issued within the past eight months.

Table 6. Combined Cycle System CO BACT Limits

Facility	Permitting Authority	Limit
Ninemile Point Plant	Louisiana DEQ	3.0 ppmvd, corrected to 15 percent O_2, annual average
FGE Texas	Texas CEQ	2.0 ppmvd, corrected to 15 percent O_2, 3-hr basis
La Paloma Energy Center	Texas CEQ	2.0 ppmvd, corrected to 15 percent O_2, 3-hr basis
Pioneer Valley Energy Center	U.S. EPA	2.0 ppmvd during gas firing, 6.0 ppmvd during oil firing, both corrected to 15 percent O_2, 1-hr basis
Avenal Power Center	U.S. EPA	2.0 ppmvd, corrected to 15 percent O_2, 1-hr basis

ADEQ has concluded that the limit proposed by the applicant represents BACT; no more stringent limit has been demonstrated to be achievable for these Combined Cycle Systems during periods of normal operation.

The proposed CO BACT limit of 2.0 ppmvd, corrected to 15% O_2, is not achievable during periods of startup, shutdown, and tuning because neither the DLN combustors nor the SCR function effectively during these periods. Thus, an exemption from this limit will be provided for these periods.

b. Periods of Startup, Shutdown, and Tuning

The CO emission limits proposed by the applicant for periods of startup, shutdown, and tuning of the Combined Cycle Systems are as follows. These proposed limits are based on the achievable performance using fast start technology from Kiewit Power Engineers Co. in conjunction with GE Frame 7FA, Model 4, combustion turbines.

(1) 131.1 lb per "hot" startup event, which is a startup event after the unit has been non-operational for a period of less than 8 hours;

(2) 145.0 lb per "warm" startup event, which are startup events after the unit has been non-operational for at least 8 but less than 72 hours;

(3) 145.0 lb per "cold" startup event, which are startup events after the unit has been non-operational for at least 72 hours;

(4) 145.0 lb/hr during tuning periods, which are periods during which the turbine is tested at various incremental loads and during which the NO_X or CO emission limits are not met; and

(5) 51.5 lb per shutdown event.

In conjunction with these emission limits, the applicant has proposed the following two operational limits:

(1) The Permittee shall not cause, allow, or permit the cumulative

duration of startup and tuning events at a Combined Cycle System to exceed 325 hours per rolling 12-month period.

(2) The Permittee shall not cause, allow, or permit the cumulative duration of shutdown events at a Combined Cycle System to exceed 91.25 hours per rolling 12-month period.

ADEQ has reviewed the information provided by the applicant and concurs with the proposed determination that there is no demonstrated control option more effective than the fast start technology from Kiewit Power Engineers Co. The limits proposed by the applicant represent BACT; no more stringent limits have been demonstrated to be achievable for these Combined Cycle Systems.

4. Greenhouse Gases (GHG)

The GHG emission limits proposed by the applicant for the Combined Cycle Systems are 1,752,769 tons per rolling 12-month period and 995 lb/MWh gross output on a 12-month rolling average basis, both on a CO_2e basis. These proposed limits are based on the achievable performance using highly efficient GE Frame 7FA, Model 4, combustion turbines. The applicant identified one control option potentially more effective for reducing GHG emissions – carbon capture and sequestration (CCS) – but determined that this option is not feasible. Specifically, the applicant concluded no CO_2 capture technology has been demonstrated in practice on a scale needed for a combined cycle power plant; no CO_2 pipeline infrastructure exists in southern Arizona, and construction of such a pipeline from the plant site to a sequestration site would face regulatory and liability issues; and no demonstrated sequestration site exists in the vicinity of the plant site.

ADEQ has reviewed the information provided by the applicant and concurs with the conclusion that technical feasibility has not been demonstrated with respect to CCS for a combined-cycle power plant in southern Arizona, particularly with respect to carbon sequestration. Notably, no suitable depleted oil and gas formations have been identified in Arizona, and evaluation of potential saline formations in Arizona, such as the pilot test conducted by WESTCARB at the Cholla Power Plant in Navajo County, have failed to identify any potential sites with sufficient permeability for commercial-scale CO_2 injection.

In light of the significant uncertainty regarding viability of CCS as a control option for fossil-fueled power plants such as the Bowie Power Station, ADEQ developed an estimate of costs of this control option as part of this BACT analysis. This analysis incorporates several highly conservative assumptions:

- CO_2 capture at 90 percent efficiency using methyldiethanol amine (MDEA) is feasible, notwithstanding the absence of demonstrated performance for this technology on exhaust gases from a natural gas-fired combustion source;

- Regulatory and liability issues associated with constructing a 400-mile pipeline from the plant site to southeastern New Mexico could be overcome;

- Permanent sequestration of CO_2 at a site in New Mexico could be made an enforceable condition of a Class I permit issued by ADEQ, notwithstanding the absence of any identified legal mechanism for such enforceability; and

- A permanent sequestration site, of sufficient capacity to store the approximately 32 million tons of CO_2 produced by the Bowie Power Station over a period of approximately 20 years, could be identified among the depleted oil and gas reservoirs near Hobbs in southeastern New Mexico, notwithstanding the absence of data supporting the viability of any such site.

As shown in Table 7, the costs of CCS, if feasible, would be extraordinary, and the cost effectiveness would be well outside the range that might be considered reasonable.

Table 7. Cost Effectiveness Analysis for CCS

Cost Category/Element	Value	Comment/Reference
Process Parameters		
Captured CO_2, tons/yr	1,576,000	90% of PTE from two Combined Cycle Systems
Uncaptured CO_2, tons/yr	175,000	10% of PTE from two Combined Cycle Systems
Pipeline Distance, miles	400	Bowie site to Hobbs, NM
Pipeline Diameter, inches	22	from DRET CCS Task Force, Summary of Pipeline Sizing Study, WorleyParsons, August 2009
Capital Costs		
Capture/Compression	$386,000,000	from Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 2, DOE/NETL-2010/1397, Nov. 2010, and Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases, DOE/NETL-341/082312, Aug. 2012. Scaled using six-tenths factor.
Pipeline	$612,000,000	from Quality Guidelines for Energy Systems Studies: Estimating Carbon Dioxide Transport and Storage Costs, DOE/NETL-2013/1614, Mar. 2013, Table 2: Pipeline Cost Breakdown
Annual Costs		
Operating & Maintenance, $/yr	$99,000,000	from Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 2, DOE/NETL-2010/1397, Nov. 2010, and Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases, DOE/NETL-341/082312, Aug. 2012.
Annualized Capital Costs, $/yr	$93,900,000	20 years at 7% cost of money (capital recovery factor of 0.094)
Total Annual Cost, $/yr	$192,900,000	
Cost Effectiveness		
Gross cost effectiveness	$122	
CO_2 from power, tons/yr	293,000	from Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev. 2, DOE/NETL-2010/1397, Nov. 2010
Net cost effectiveness, $/ton	$150	

In the permit application submitted in September 2013, the applicant presented a tabulation of recently established GHG emission limits for comparable natural gas-fired combined cycle systems. In order to ensure the BACT determination is made using the most current information, ADEQ identified and reviewed additional permits, as shown in Table 8, including permits issued within the past eight months.

Table 8. Combined Cycle System GHG BACT Limits

Facility	Permitting Authority	Limit(s) (annual average)
Marshalltown Generating Station	Iowa DNR	1,318,647 tpy (CO_2e basis) and 951 lb/MWh (gross) (CO_2 only)
Scattergood Generating Station	South Coast (Calif.) AQMD	1,026,128 tpy (CO_2e basis) and 936 lb/MWh (net) (CO_2e basis)
Pioneer Valley Energy Center	U.S. EPA	895 lb/MWh (net) (CO_2e basis)
Port Everglades Plant	U.S. EPA	830 lb/MWh (net) (CO_2e basis) when burning natural gas (permit also allows oil firing)
FGE Texas	U.S. EPA	1,472,228 tpy (CO_2e basis) and 889 lb/MWh (gross) (CO_2 only)
La Paloma Energy Center	U.S. EPA	1,263,055 tpy (CO_2e basis) and 934.5 lb/MWh (gross) (CO_2 only)

This information supports the applicant's contention that 876,385 tons per year (CO_2e basis) represents BACT, without regard to overall system efficiency on an ongoing basis, for the proposed Combined Cycle Systems.

As noted above, a GHG emissions limit expressed in tons per year does not, by itself, ensure operation at high efficiency. For this reason, U.S. EPA and a number of state and local PSD permitting authorities have imposed output-based GHG emission limits as BACT for natural gas-fired, combined cycle electric power plants like the Bowie Power Station. Although an output-based limit is not expressly required by the Clean Air Act, as a matter of policy, ADEQ has elected to impose one, in order to ensure conformance with the statutory requirement that BACT reflect the maximum degree of reduction in GHG emissions achievable.

The applicant's proposed output-based limit of 995 lb/MWh gross output on a 12-month rolling average basis, CO_2e basis, reflects a lower average efficiency than the limits imposed on several generally similar facilities. (In ADEQ's estimation, the applicant's proposed output-based limit is equivalent to approximately 1,025 lb/MWh net output, assuming three percent efficiency loss in the step-up transformer.) At ADEQ's request, in supplemental information provided in June 2014, the applicant presented detailed data supporting the proposed limit. The basis for the limit includes the following key assumptions:

- A total of 3,463.5 annual operating hours, with 80 percent of operating hours at an ambient temperature of 102 °F and 20 percent of operating hours at an ambient temperature of 59 °F.

- All 2,715.25 normal (*i.e.*, non-startup/shutdown) operating hours at an ambient temperature of 102 °F are at 100 percent load with duct firing.

- Of 550 normal (*i.e.*, non-startup/shutdown) operating hours at an ambient temperature of 59 °F, 124 hours are at 100 percent load with duct firing and 426 are at minimum compliance load with no duct firing.

- One startup and one shutdown every other day, including 61 hot starts at an ambient temperature of 102 °F and 122 warm starts at an ambient temperature of 59 °F.

- During all operating hours, only one of the facility's two CTG's operates.

- A 3.3 percent design margin reflecting the possibility that the constructed facility will not be able to achieve the design heat rate.

- A 6.0 percent performance margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls.

- A 3.0 percent degradation margin reflecting the variability in operation of auxiliary plant equipment due to use over time.

These assumptions, which ADEQ considers to be reasonable and appropriate for purposes of establishing an output-based GHG emission limit, reflect operation of a highly efficient facility under the conditions that are least conducive to high efficiency. The average efficiency will be higher (*i.e.*, GHG emissions per MWh output will be less) if the facility operates at higher overall production rates, with two CTG's operating in parallel, or if, in addition to the operating hours described above, the facility operates during cold-weather conditions. However, ADEQ will not impose a GHG BACT emission limit that would require the facility to operate a greater number of hours or at higher overall production rates in order to improve long-term average efficiency, as either of these requirements would result in increased emissions of all pollutants from this facility.

Accordingly, ADEQ has concluded that the limits proposed by the applicant represent BACT; no more stringent GHG emission limits have been demonstrated to be achievable for these Combined Cycle Systems.

C. Auxiliary Boiler

The applicant has proposed that the Auxiliary Boiler will be equipped with low-NO_X burners to control NO_X emissions. Emissions of particulate matter, CO, and GHG will be minimized through inherent design elements such as fuel selection and good combustion practices. In addition, the applicant has proposed to limit the operation of the Auxiliary Boiler to 450 hours per year.

1. Particulate Matter (PM/PM10/PM2.5)

The emission limit proposed by the applicant is 0.35 lb/hr based on the achievable performance with the design elements inherent in the proposed project.

There are no known applications of add-on controls for the purpose of controlling particulate matter emissions from natural gas-fired boilers and no evidence that such controls would result in quantifiable emission reductions. Moreover, even if any add-on controls were technically feasible for further reduction of particulate matter emissions, the resultant economic costs would obviously outweigh the achievable emission reduction.

ADEQ has concluded that the limit proposed by the applicant represents BACT; no more stringent limit has been demonstrated to be achievable for the Auxiliary Boiler.

2. Nitrogen Oxides (NO_X)

The NO_X emission limit proposed by the applicant is 0.011 lb per MMBtu heat input. This proposed limit is based on the achievable performance using low-NO_X burners. The applicant identified two control options potentially more effective for reducing NO_X emissions – SCR and selective non-catalytic reduction (SNCR) – but determined that these options are not reasonably cost effective for the proposed Auxiliary Boiler. ADEQ has reviewed the information provided by the applicant and concurs with the applicant's determinations regarding these control options.

ADEQ has concluded that the limit proposed by the applicant represents BACT; no more stringent limit has been demonstrated to be achievable for the Auxiliary Boiler.

3. Carbon Monoxide (CO)

The CO emission limit proposed by the applicant is 0.037 lb per MMBtu heat input. This proposed limit is based on the achievable performance using low-NO_X burners and good combustion practices. The applicant identified one control option potentially more effective for reducing CO emissions – oxidation catalyst – but determined that this option is not technically feasible for this application due to the high efficiency and low exhaust gas temperature of the proposed Auxiliary Boiler. ADEQ has reviewed the information provided by the applicant and concurs with the applicant's determination; in addition, ADEQ notes that, even if it were technically feasible in this application, oxidation catalyst would not be reasonably cost effective due to the minimal CO emission reduction achievable.

ADEQ has concluded that the limit proposed by the applicant represents BACT; no more stringent limit has been demonstrated to be achievable for the Auxiliary Boiler.

4. Greenhouse Gases (GHG)

The GHG emission limit proposed by the applicant for the Auxiliary Boiler is 1,316.5 tons per year (CO_2e basis). This proposed limit is based on the achievable performance using a highly efficient boiler. The applicant did not identify any more effective control options. ADEQ notes that CCS is theoretically feasible for the Auxiliary Boiler but would not be cost effective in this application.

ADEQ has concluded that the limit proposed by the applicant represents BACT; no more stringent GHG emission limit has been demonstrated to be achievable for the Auxiliary Boiler.

D. Cooling Tower

The proposed mechanical draft wet cooling tower has the potential to emit only particulate matter (including PM, PM10, and PM2.5).

The applicant proposed that BACT for particulate matter emissions from the mechanical draft wet cooling tower be established as an equipment design standard: Use of high-efficiency drift eliminators with a specified maximum drift level of 0.0005 percent or less. In conjunction with the proposed maximum dissolved solids level of 4,039 parts per million by weight (ppmw) in cooling water, this equipment design standard is estimated to yield maximum hourly emission rates of 1.3 lb PM, 0.9 lb PM10, and 0.4 lb PM2.5.

The applicant identified two alternative facility designs that have the potential for reducing emissions of particulate matter – dry cooling and hybrid cooling – but determined that these alternative designs do not represent BACT because they would cause significant, adverse environmental, energy, and economic impacts that are unreasonable in comparison to the achievable reduction in particulate matter emissions. ADEQ has reviewed the information provided by the applicant and concurs with the applicant's conclusion. In particular, ADEQ concludes that the five percent decrease in generating capacity at high ambient temperatures renders these alternative facility designs as questionable for consideration in the BACT analysis: The stationary source for which ADEQ received an air permit application is a plant with nominal electric generating capacity of 525 MW, and implementation of either of these alternative facility designs would reduce the nominal capacity to approximately 500 MW. If it is conservatively assumed that these alternative facility designs are properly evaluated as "control options" in the BACT analysis, ADEQ agrees that the adverse impacts of these options, particularly due to the energy penalty, render them unacceptable as BACT. Because replacement of the proposed mechanical draft wet cooling tower with an entirely different facility design is rejected, drift eliminators are the only technically feasible control option.

As provided by A.A.C. R18-2-406.A.4, equipment design standards are acceptable as BACT where ADEQ determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of a numeric emission limit infeasible. This is true with respect to the mechanical draft wet cooling tower; reference test methods for particulate matter emissions cannot be conducted due to the configuration of the tower.

ADEQ has concluded that the equipment design standard proposed by the applicant represents BACT; no more stringent emission limit has been demonstrated to be achievable for the mechanical draft wet cooling tower.

E. Emergency Fire Pump

The applicant has proposed to minimize emissions of particulate matter, NO_X, and CO, and GHG from the Diesel-Fired Emergency Fire Pump through inherent design elements such as combustion controls and fuel selection. In addition, the applicant has proposed to limit the operation of the pump to 100 hours per year in non-emergency situations.

1. Particulate Matter (PM/PM10/PM2.5)

The applicant proposed that BACT for the Diesel-Fired Emergency Fire Pump be established as an equipment design standard: Purchase of an engine certified to meet the emission standards in 40 CFR § 60.4205(c) for the same model year and National Fire Protection Association (NFPA) nameplate engine power. This equipment design standard is estimated to yield a maximum annual particulate matter emission rate of 0.003 tpy.

The applicant identified several types of add-on control equipment relying on filtration to reduce emissions of particulate matter from the pump engine but determined that these options are not reasonably cost effective for the proposed engine. ADEQ has reviewed the information provided by the applicant and concurs with the applicant's conclusion.

As provided by A.A.C. R18-2-406.A.4, equipment design standards are acceptable as BACT where ADEQ determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of a numeric emission limit infeasible. This is true with respect to particulate matter emissions from the Diesel-Fired Emergency Fire Pump; emissions testing of the installed engine would be unreasonably costly and burdensome in light of the certification requirements for compression-ignition internal combustion engines.

ADEQ has concluded that the limit proposed by the applicant represents BACT; no more stringent limit has been demonstrated to be achievable for the Diesel-Fired Emergency Fire Pump.

2. Nitrogen Oxides (NO_X)

The applicant proposed that BACT for the Diesel-Fired Emergency Fire Pump be established as an equipment design standard: Purchase of an engine certified to meet the emission standards in 40 CFR § 60.4205(c) for the same model year and NFPA nameplate engine power. This equipment design standard is estimated to yield a maximum annual NO_X emission rate of 0.06 tpy.

The applicant identified two control options potentially more effective for reducing NO_X emissions – SCR and SNCR – but determined that these options are not reasonably cost effective for the proposed engine. ADEQ has reviewed the information provided by the applicant and concurs with the applicant's determinations regarding these control options.

As provided by A.A.C. R18-2-406.A.4, equipment design standards are acceptable as BACT where ADEQ determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of a numeric emission limit infeasible. This is true with respect to NO_X emissions from the Diesel-Fired Emergency Fire Pump; emissions testing of the installed engine would be unreasonably costly and burdensome in light of the certification requirements for compression-ignition internal combustion engines.

ADEQ has concluded that the limit proposed by the applicant represents BACT; no more stringent limit has been demonstrated to be achievable for the Diesel-Fired Emergency Fire Pump.

3. Carbon Monoxide (CO)

The applicant proposed that BACT for the Diesel-Fired Emergency Fire Pump be established as an equipment design standard: Purchase of an engine certified to meet the emission standards in 40 CFR § 60.4205(c) for the same model year and NFPA nameplate engine power. This equipment design standard is estimated to yield a maximum annual CO emission rate of 0.04 tpy.

The applicant identified several types of add-on control equipment relying on catalytic oxidation to reduce emissions of CO from the pump engine but determined that these options are not reasonably cost effective for the proposed engine. ADEQ has reviewed the information provided by the applicant and concurs with the applicant's conclusion.

As provided by A.A.C. R18-2-406.A.4, equipment design standards are acceptable as BACT where ADEQ determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of a numeric emission limit infeasible. This is true with respect to CO emissions from the Diesel-Fired Emergency Fire Pump; emissions testing of the installed engine would be unreasonably costly and burdensome in light of the certification requirements for compression-ignition internal combustion engines.

ADEQ has concluded that the limit proposed by the applicant represents BACT; no more stringent limit has been demonstrated to be achievable for the Diesel-Fired Emergency Fire Pump.

4. Greenhouse Gases (GHG)

The GHG emission limit proposed by the applicant for the Diesel-Fired Emergency Fire Pump is 15.0 tons per year (CO_2e basis). This proposed limit is based on the achievable performance with the design elements inherent in the proposed pump and with the proposed fuel selection. The applicant did not identify any more effective control options. ADEQ notes that CCS is theoretically feasible for the proposed engine but would not be cost-effective in this application.

ADEQ concurs with the applicant's conclusions regarding the technological basis for BACT and will impose a GHG emission limit equivalent in stringency. However, ADEQ has elected to express the GHG emission limit as 22.6 lb per gallon of fuel combusted (CO_2e basis), with compliance demonstrated using the default emission factors and high heat values in 40 CFR part 98, subpart C. No more stringent GHG emission limit has been demonstrated to be achievable for the Diesel-Fired Emergency Fire Pump.

F. Circuit Breakers

The proposed Circuit Breakers are potential sources of GHG emissions due to the use of SF_6 for insulation and arc protection. They will not have the potential to emit any other regulated NSR pollutant.

The applicant has proposed to minimize emissions of GHG from the Circuit Breakers through application of a work practice requirement: leak detection monitoring.

The applicant identified several alternative facility designs that have the potential for reducing emissions of GHG through the use of circuit breakers that do not contain SF_6 but determined that these alternative designs do not represent BACT because they are not technically feasible. ADEQ has reviewed the information provided by the applicant and has concluded that the alternative facility designs do not represent BACT, but based on a rationale that differs slightly from the applicant's: The stationary source for which ADEQ received an air permit application is a plant with high-voltage transmission capability and using demonstrated, reliable technology for insulation and arc protection. Use of alternative circuit breaker technology would require either lower voltage transmission or use of undemonstrated technology for insulation and arc protection and is therefore fundamentally inconsistent with the proposed facility design.

As provided by A.A.C. R18-2-406.A.4, equipment design standards and work practice requirements are acceptable as BACT where ADEQ determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of a numeric emission limit infeasible. This is not true with respect to GHG emissions from circuit breakers; compliance with an emission limit can be demonstrated using a mass balance approach.

As shown in Table 9, ADEQ identified and reviewed permits with recently established GHG emission limits for circuit breakers.

Based on the emission limits demonstrated to be achievable at similar facilities, ADEQ is imposing a GHG emission limit of 103 tons per rolling 12-month period (CO_2e basis, total for five circuit breakers). This represents a maximum annual SF_6 leak rate of 0.5 percent.

Table 9. Circuit Breaker GHG BACT

Facility	Permitting Authority	Limit
Scattergood Generating Station	South Coast (Calif.) AQMD	55.4 tons per calendar year (CO_2e basis) (based on 0.5 percent annual leak rate)
Port Everglades Plant	U.S. EPA	None; work practices only.
FGE Texas	U.S. EPA	None; work practices only.
La Paloma Energy Center	U.S. EPA	None; work practices only.
Cheyenne Prairie Generating Station	U.S. EPA	64.5 tons per calendar year (CO_2e basis) (based on 1.0 percent annual leak rate)
Palmdale Hybrid Power Project	U.S. EPA	9.56 tons per rolling 12-month period (CO_2e basis) (based on 0.5 percent annual leak rate)
Pio Pico Energy Center	U.S. EPA	40.2 tons per calendar year (CO_2e basis) (based on 0.5 percent annual leak rate)

G. Natural Gas Piping

Natural gas piping within the Bowie Power Station is a potential source of GHG emissions due to the presence of methane and the potential presence of CO_2. Potential GHG emissions from natural gas piping are less than two tons per year, or approximately 0.0001 percent of the facility's total GHG emissions.

The applicant has proposed to minimize emissions of GHG from natural gas piping through application of a work practice requirement: leak detection monitoring using auditory/visual/olfactory means.

As shown in Table 10, ADEQ identified and reviewed recently issued PSD permits for similar facilities in order to identify the requirements imposed as BACT for GHG emissions from natural gas piping.

Table 10. Natural Gas Piping GHG BACT

Facility	Permitting Authority	BACT
Scattergood Generating Station	South Coast (Calif.) AQMD	No limits or other requirements.
Port Everglades Plant	U.S. EPA	No limits or other requirements.
FGE Texas	U.S. EPA	Auditory/visual/olfactory leak detection.
La Paloma Energy Center	U.S. EPA	Auditory/visual/olfactory leak detection.
Cheyenne Prairie Generating Station	U.S. EPA	16 tons CH_4 per calendar year (using assumed emission factors; no monitoring required).
Palmdale Hybrid Power Project	U.S. EPA	No limits or other requirements.
Pio Pico Energy Center	U.S. EPA	No limits or other requirements.

As provided by A.A.C. R18-2-406.A.4, equipment design standards and work practice requirements are acceptable as BACT where ADEQ determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of a numeric emission limit infeasible. This criterion is met with respect to GHG emissions from natural gas piping.

Based on the negligible quantity of GHG emissions from natural gas piping and the requirements imposed on similar facilities, ADEQ concurs with the applicant's proposed BACT.

VII. PREVIOUS PERMIT CONDITIONS

This is the initial Air Quality Class I Permit for the Bowie Power Station project.

VIII. MONITORING AND RECORD KEEPING REQUIREMENTS

A. Combined Cycle Systems

1. The Permittee is required continuously to monitor and record fuel flow to each Combined Cycle System.

2. The Permittee is required to record daily the periods of operation of each Combined Cycle System with notation of the operating mode (startup, shutdown, tuning, normal operation with duct firing, or normal operation without duct firing) in hours and minutes.

3. The Permittee is required to install, calibrate, maintain, and operate continuous emissions monitoring systems (CEMS) for NO_X, CO, and O_2 for each Combined Cycle System.

4. The Permittee is required to maintain records of a current, valid purchase contract, tariff sheet or transportation contract for natural gas combusted in each Combined Cycle System.

5. The Permittee is required to maintain records of VOC and GHG emissions calculations for each Combined Cycle System.

B. Auxiliary Boiler

1. The Permittee is required to maintain monthly records of the fuel use in the Auxiliary Boiler.

2. The Permittee is required to record daily the periods of operation of the Auxiliary Boiler in hours and minutes.

3. The Permittee is required to maintain records of GHG emissions for the Auxiliary Boiler.

C. Mechanical Draft Wet Cooling Tower

1. The Permittee is required continuously to monitor and record the circulating water flow rate to the Mechanical Draft Wet Cooling Tower.

2. The Permittee is required to monitor and record the conductivity of the circulating water in the mechanical draft cooling tower daily and to measure and record the total dissolved solids of the circulating water at least once per month.

3. The Permittee is required to maintain readily available records of the certified design total drift rate of the Mechanical Draft Wet Cooling Tower as specified by the cooling tower vendor.

D. Diesel-Fired Emergency Fire Pump

1. The Permittee is required to install and operate a non-resettable meter to record the hours of operation of the Diesel-Fired Emergency Fire Pump.

2. The Permittee is required to record daily the hours of operation of the Diesel-Fired Emergency Fire Pump with notation of whether the operation is for purposes of readiness testing, maintenance checks, or another purpose.

3. The Permittee is required to maintain monthly records of the fuel use in, and GHG emissions from, the Diesel-Fired Emergency Fire Pump.

E. Circuit Breakers

1. The Permittee is required to implement a leak detection monitoring program for each Circuit Breaker.

2. The Permittee is required to maintain monthly records of GHG emissions from all Circuit Breakers.

F. Natural Gas Piping

The Permittee is required to implement a leak detection monitoring program for natural gas piping using auditory/visual/olfactory methods.

G. Fugitive Dust

1. The Permittee is required to keep record of the dates and types of dust control measures employed.

2. The Permittee is required to show compliance with the opacity standards by having a Method 9 certified observer perform a survey of visible emission from fugitive dust sources. The observer is required to conduct a 6-minute Method 9 observation if the results of the initial survey appear on an instantaneous basis to exceed the applicable standard.

3. The Permittee is required to keep records of the name of the observer, the time, date, and location of the observation and the results of all surveys and observations.

4. The Permittee is required to keep records of any corrective action taken to lower the opacity of any emission point and any excess emission reports.

H. Periodic Activities

1. The Permittee is required to record the date, duration and pollution control measures of any abrasive blasting project.

2. The Permittee is required to record the date, duration, quantity of paint used, any applicable MSDS, and pollution control measures of any spray painting project.

3. The Permittee is required to maintain records of all asbestos related demolition or renovation projects. The required records include the "NESHAP Notification for Renovation and Demolition Activities" form and all supporting documents.

I. Mobile Sources

The Permittee is required to keep records of all emission related maintenance performed on the mobile sources.

IX. **TESTING REQUIREMENTS**

A. Combined Cycle Systems

1. The Permittee is required to perform initial performance testing of each Combined Cycle System for particulate matter, NO_X, and VOC emissions at several representative operating loads.

2. The Permittee is required to perform initial and biennial performance testing of each Combined Cycle System for ammonia emissions.

3. The Permittee is required to perform initial and annual performance tests for the sulfur content of natural gas combusted in each Combined Cycle System. (Although described as a performance test in 40 CFR part 60, subpart KKKK, this fuel sampling and analysis is not considered by ADEQ to be a "performance test" for purposes of A.A.C. R18-2-312.)

B. Auxiliary Boiler

1. The Permittee is required to perform initial performance testing of the Auxiliary Boiler for particulate matter, NO_X, CO, and VOC emissions.

C. Diesel-Fired Emergency Fire Pump

1. The Permittee is required to perform quarterly observations of opacity of visible emissions from the Diesel-Fired Emergency Fire Pump.

X. **COMPLIANCE HISTORY**

This is the initial Air Quality Class I Permit for the Bowie Power Station project.

XI. AMBIENT AIR IMPACT ANALYSIS

A. Ambient Air Quality Impacts Analysis

1. General

ADEQ requires air dispersion modeling for new PSD major sources and PSD major modifications under authority from the A.A.C. R18-2-406.A5 and -406.A.6. In addition, ADEQ generally requires that permit applicants perform NAAQS modeling analyses for minor sources and minor modifications under the authority of the Arizona Laws Relating to Environmental Quality, A.R.S. § 49-422.

For the Bowie Power Station project, PSD ambient air quality analysis requirements are applicable to NO_X, CO, PM2.5, and PM10. In addition, ADEQ has required a SO_2 NAAQS analysis to be performed.

Guidance for performing air quality dispersion modeling analyses is set forth in Appendix W to 40 CFR part 51, adopted by reference in A.A.C. R18-2-406.A.6; in Chapter C of U.S. EPA's draft October 1990 *New Source Review Workshop Manual*; and in the *Air Dispersion Modeling Guidelines for Arizona Air Quality Permits*, September 23, 2013. A modeling analysis is typically performed in two steps: a facility-only "preliminary" or "significant impact" analysis and, if required, a "cumulative" or "full" impact analysis. The significant impact analysis estimates ambient concentrations resulting from the proposed project for pollutants that trigger PSD requirements. If the ambient impacts from the project are greater than the Significant Impact Levels (SILs, see Table 11), then the extent of the Significant Impact Area (SIA) of the proposed project is determined and a cumulative analysis is performed within the SIA. The cumulative analysis considers emissions both from the proposed project and from other nearby sources. The source inventory for the cumulative NAAQS analysis generally includes all nearby sources that have significant impacts within the proposed source SIA, while the source inventory for the cumulative PSD analysis is limited to increment-effecting sources (new sources and changes to existing sources that have occurred since the applicable increment baseline date). The modeling results from the NAAQS cumulative impact analysis are added to representative ambient background concentrations and the total concentrations are compared to the NAAQS. The SILs give meaning to the ambiguous phrase "cause or contribute" in A.A.C. R18-2-406.A.5 and Clean Air Act § 165(a)(3); according to ADEQ and U.S. EPA policy, if the PSD cumulative impact analysis indicates potential violations of any NAAQS or PSD increment, the proposed facility can still be permitted if it can be demonstrated that the facility does not result in ambient impacts that exceed the SIL at the same time and location of any modeled violation.

For PSD minor sources and modifications, ADEQ generally requires that applicants model criteria pollutant impacts for comparison to the NAAQS. Unlike the methods used in PSD NAAQS analyses, other nearby sources are typically not included, and instead representative background concentrations are added to include the effects of other sources.

Table 11. National Ambient Air Quality Standards (NAAQS), Class II Significant Impact Levels (SILs), and PSD Class II Increments (*μg/m³*)

Pollutant	Averaging Period	NAAQS	Class II SIL	Class II PSD Increment
NO_2	Annual	100	1	25
	1-hour [a]	188	7.5	n/a
SO_2	Annual	80	1	20
	24-hour [b]	365	5	91
	3-hour [b c]	1,300	25	512
	1-hour [d]	195	7.8	n/a
CO	8-hour [b]	10,000	500	n/a
	1-hour [b]	40,000	2000	n/a
PM10	Annual [e]	n/a	1	17
	24-hour [f]	150	5	30
PM2.5	Annual [g]	15	0.3	4
	24-hour [h]	35	1.2	9

Footnotes:
[a] The multi-year average of the 98th percentile of the annual distribution of daily maximum 1-hour average concentrations must not exceed the standard. The U.S. EPA has recommended an interim significant impact level (SIL) of 7.5 μg/m³.
[b] Not to be exceeded more than once per year
[c] National standard will be revoked following a transition period.
[d] The multi-year average of the 99th percentile of the annual distribution of daily maximum 1-hour average concentrations must not exceed the standard. The U.S. EPA has recommended an interim significant impact level (SIL) of 7.8 μg/m³.
[e] National standard revoked effective December 17, 2006; annual AAAQS is still listed at A.A.C. R18-2-201(A)(1)(a).
[f] Not to be exceeded more than once per year on average over three years.
[g] The average annual mean must not exceed the standard.
[h] The average of the yearly 98th percentile of 24-hour concentrations must not exceed the standard.
n/a - Indicates there is no applicable concentration level.

2. Summary of Air Quality Impact Analysis Methodology

a. Air Dispersion Computer Model

The U.S. EPA recommended refined air dispersion model for air quality impact analyses is the AMS/EPA Regulatory Model (AERMOD). Version 13350 of AERMOD was approved for use by ADEQ for the analysis. Given the distinctly rural nature of the Bowie project area, the rural dispersion option in AERMOD was selected.

b. Receptor Grid

A model receptor grid was used with sufficient density to determine the maximum model-predicted impact within the surrounding ambient air. Elevation data was derived from the National Elevation Dataset maintained by the United States Geological Service. The smallest receptor grid spacing was set at 25 meters at the project ambient air boundary and at additional areas where the predicted concentration exceeded 90 percent of an applicable standard or threshold and the Bowie project contributed more than 3 percent to the predicted concentration. The receptor grid used varying density and extended to a distance of 50 km from the Project location. Receptor elevations and hill heights were derived using U.S. EPA's AERMAP program version 11103. The procedures used by the applicant conform to U.S. EPA and ADEQ guidance.

There are no nonattainment areas within 50 km of the Bowie project location. Therefore, no special receptors were required to calculate nonattainment impacts.

c. Meteorological Data

The applicant collected one year of meteorological data on the proposed plant site starting in April 2001. The parameters included wind speed, wind direction, and sigma theta data at a height of 10 meters above ground level, ambient temperature at a height of 2.6 meters above ground level, and station barometric pressure; the data completeness for all parameters exceeds 99 percent for each of the four quarters. This dataset has previously been approved as site-specific data by ADEQ. In addition to the onsite meteorological data, surface meteorological data from Safford, Arizona, and upper air meteorological data from Tucson, Arizona, were used. The meteorological data were processed using AERMET version 12345 in accordance with U.S. EPA and ADEQ guidance (including EPA's January 23, 2014 statements on the status of AERMET version 13350). The AERSURFACE version 13016 program was used to derive surface characteristic data for input to AERMET using the 1992 National Land Cover Dataset. Four sectors were used to identify areas of similar land use around the onsite meteorological station. The data and procedures used by the applicant conform to U.S. EPA and ADEQ guidance.

d. Downwash and Good Engineering Practice (GEP)

U.S. EPA's BPIPPRIME program was used to calculate the building downwash parameters for input to AERMOD. All the facility stacks are subject to downwash. All stacks are also below the minimum 65 meter allowable GEP height, therefore all stack heights are fully creditable for air quality modeling.

e. Ambient Air Quality Data

Ambient air quality background data is required by ADEQ for NAAQS impact analyses for both PSD and non-PSD permit applications, as described in ADEQ's *Air Dispersion Modeling Guidelines for Arizona Air Quality Permits*. In general, the background air quality concentration is intended to account for sources not explicitly included in the NAAQS modeling analysis.

In addition to this background data requirement, the PSD regulations at A.A.C. R18-2-407 contain a pre-construction ambient air monitoring requirement. The basic objective of PSD pre-construction monitoring is to determine the effect emissions from a source are having or may have on the air quality in any area that may be affected by the emission. Historically, the applicability of the PSD pre-construction monitoring requirement has been determined by comparing the maximum model predicted project impacts to EPA's Significant Monitoring Concentration (SMC) thresholds; if the project impact for a particular pollutant was above the relevant SMC, then the PSD pre-construction monitoring requirement was applicable for that pollutant. On January 22, 2013, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating the SMC for PM2.5. Although this court decision contained no holdings with respect to the validity of the SMCs for any other pollutant, it has created some uncertainty on the regulatory authority for reliance on the SMCs.

As will be discussed later in this technical review, the maximum modeled Project impacts for the pollutants CO, SO_2, annual NO_2, and PM10/PM2.5 were below the applicable SILs and SMCs. Since the impacts were below the SILs, background concentration data for cumulative NAAQS impact analyses are not required for these pollutants. Additionally, because these Project impacts are below the SMCs, the codified PSD regulations would not require preconstruction monitoring data for any of these pollutants. However, to address the uncertainties resulting from the 2013 Court of Appeals decision, ADEQ requested that Bowie address the PSD preconstruction monitoring requirements for all pollutants that trigger PSD review requirements. Note that PSD pre-construction monitoring is required for ozone because the Project emissions of the ozone precursor NO_X are greater than 100 tpy.)

The PSD preconstruction monitoring requirement can be met either by collecting continuous ambient monitoring data or by using representative existing monitoring data, and Bowie elected to use representative existing monitoring data. U.S. EPA's *PSD Monitoring Guidelines*, other U.S. EPA interpretive guidance, and U.S. EPA administrative decisions clarify that representative, existing air quality monitoring data may be used to fulfill the PSD pre-construction monitoring requirements and establish background concentrations needed for assessing NAAQS compliance. U.S. EPA's *PSD Monitoring Guidelines* suggest specific criteria to determine the representativeness of existing, off-site monitoring data, including the quality of the data, the currentness of the data, and the location of the monitoring data. Because the Bowie project is located in a relatively remote location which is generally free from the impact of other point sources and area sources associated with human activities, and because the immediate project area is in flat terrain, U.S. EPA guidance states that data from a "regional" monitoring station may be used as representative data. The Bowie modeling report presents an analysis of available, existing monitoring data against these criteria. The analysis also includes detailed comparisons of nearby emission source distances and directions at both the Bowie project site as well as at the existing monitoring stations. Based on these analyses, Bowie has proposed representative, existing monitoring data that meet the PSD preconstruction requirements. The background concentrations were determined from these data in accordance with procedures in Section 3.10 of ADEQ's *Air Dispersion Modeling Guidelines for Arizona Air Quality Permits*, and the procedures for processing 1-hr NO_2 background concentration data as described in U.S. EPA's *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-Hour NO_2 National Ambient Air Quality Standard*, March 1, 2011. Therefore, ADEQ has determined that the proposed existing monitoring data fulfills both the PSD preconstruction monitoring requirements as well as the general requirements for background data for any required cumulative NAAQS analyses.

The background air quality concentrations are listed in Table 12, as well as the difference between the NAAQS and the corresponding background concentration. As will be discussed later in this technical review, a cumulative 1-hr NO_2 NAAQS analysis was required, and the applicant elected to use seasonally and diurnally varying NO_2 background concentrations for the modeling analysis. The 98th percentiles of the daily maximum hourly NO_2 data for the three year data set were averaged by season and hour of day, and the values presented in Table 12 for the 1-hr NO_2 background concentration are the range of background concentrations over all seasons and hours of the day.

Table 12. Ambient Background Air Quality Data

Pollutant	Averaging Period	Background Concentration (μg/m^3)	Station	Difference between NAAQS and Background Concentration (μg/m^3)
PM10	24-hour	43	Chiricahua NM	107
	Annual	8.3		N/A
PM2.5	24-hour	9.0	Chiricahua NM	26
	Annual	3.5		11.5
CO	1-hour	2,414	22nd & Craycroft Pima County	37,586
	8-hour	1,264		8,736
	1-hour	22.6	22nd & Craycroft Pima County	173
	3-hour	37.7		1,262.30
SO_2	24-hour	10.5		355
	Annual	2.3		78
NO_2	1-hour	2 to 50	Deming, New Mexico	>138
	Annual	8.6		91
Ozone	8-hour	73 ppb	Chiricahua NM	N/A

f. NO_2 Conversion Methodology

The majority of NO_X emissions from combustion sources are in the form of nitric oxide (NO), whereas U.S. 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. Appendix W provides a three-tiered approach to calculating annual average NO_2 impacts, and U.S. EPA has issued two additional guidance memoranda on methods for performing 1-hr NO_2 analyses (*Applicability of Appendix W Modeling Guidance for the 1-hour NO_2 NAAQS*, dated June 28, 2010, and *Additional Clarification Regarding the Application of Appendix W modeling guidance for the 1-hr NO_2 NAAQS*, dated March 1, 2011). Based on this guidance, the applicant elected to use the Tier 2 Ambient Ratio Method (ARM) for the 1-hr significant impact and NAAQS NO_2 analyses with the default ARM ratios of 0.80, and full conversion for the annual NO_2 analyses.

g. Source Data for the Project

The project emission units include two GE Frame 7FA combustion turbines (nominal 172 MW generating capacity and 1,734.6 MMBtu/hr HHV heat input capacity) with two Heat Recovery Steam Generators (HRSGs) equipped with duct firing (420 MMBtu/hr heat input), a natural gas-fired 50 MMBtu/hr auxiliary boiler with a requested operating limit of 450 hrs/yr, a 260 hp diesel-fired emergency fire pump with a requested operating limit of 100 hrs/yr, and a 127,860 gallons per minute nine-cell cooling tower.

For the combustion turbines, emissions and stack exhaust parameters (temperature and flow rate) will vary with load, ambient temperature, and operating scenario (normal operation, duct burner operation, and startup/shutdown operation). Therefore, the applicant performed load screening analyses for the turbine/HRSG stacks to determine the worst-case stack parameter scenario. The scenarios analyzed are described in detail in Section E.5.2.2.4 of the permit application. The stack parameters considered included a startup/shutdown scenario, 100 percent load operation, 80 percent load operation, and a Minimum Compliance Load (MCL) scenario which is defined as the minimum load at which a turbine exhaust concentration of 9 ppmvd NOx can be achieved (this varies from 64 percent load at 10 °F ambient temperature to 50 percent load at 59 °F to 61 percent load at 102 °F). A unitized emission rate was used in the combustion turbine load screening analysis. The results indicate that for all short-term averaging periods, the MCL stack parameter scenario always resulted in the highest impacts at any given ambient temperature, and the single scenario with the highest overall impact was the MCL stack parameters at 59 °F ambient temperature.

Load screening was not performed by the applicant for the emergency fire pump and the auxiliary boiler. The applicant is proposing to limit the emergency fire pump operations to 100 hrs/yr and the auxiliary boiler operations to 450 hrs/yr. These intermittent sources are exempted from 1-hr NO_2 and SO_2 impact analyses by U.S. EPA guidance. In addition, the emergency fire pump has relatively small emissions and will likely be operated at or near full load during testing. Therefore, ADEQ does not believe that load screening for the emergency fire pump is necessary. ADEQ has performed load screening for the auxiliary boiler at 100 percent, 75 percent, and 50 percent loads using linear ratios for unitized emissions and stack flow rates. For all short-term averaging periods the maximum auxiliary boiler impact occurs for 100 percent load operation, and this is the load that was used by the applicant for all subsequent modeling analyses.

For the "project-only" CO significant impact analysis, the "worst-case" combustion turbine stack parameters for MCL at 59 °F were paired with the maximum short-term CO emission rate (from a hot start operating scenario) to result in the maximum possible modeled 1-hr and 8-hr CO concentrations. This reduces the number of model runs needed for the CO impact analysis.

For significant impact analyses of short-term SO_2, PM10, and direct PM2.5 impacts, both the 100 percent load and worst-case (MCL) combustion turbine operating scenarios were modeled (for the 1-hr and 3-hr SO_2 analysis, a startup/shutdown scenario was also analyzed). The stack parameters and emissions for each scenario were varied seasonally to account for ambient temperature variations; stack parameters and emissions for 10 °F were used for months with average minimum temperatures below freezing (December and January), 102 °F parameters/emissions were used for months with average maximum temperatures higher than 90 °F (June, July, August, and September), and 59 °F parameters/emissions were used for the remaining months. ADEQ has performed additional sensitivity analyses of the 1-hr SO_2 and direct 24-hr PM2.5 significant impact analyses (the two pollutants/averaging intervals with ambient impacts closest to the SILs) to determine if a simple "worst case combination" of maximum emissions (without seasonal variations) and worst-case stack parameters (MCL at 59 °F as determined by the load screening analysis) result in the same conclusions as the more complex seasonally-varying approach used by the applicant. The 1-hr SO_2 SIA sensitivity results indicate that the worst case combination of maximum SO_2 emissions (100 percent load with duct burner firing) and the MCL 59 °F stack parameters resulted in model predicted concentrations below the SIL. For the 24-hr PM2.5 SIA analysis, two "worst case combinations" were modeled for the combustion turbines. The first combination used the PM2.5 emissions for 100 percent load with duct burner operation combined with 80 percent load stack parameters; this combination was used to define an enforceable permit condition that addressed the applicant's statement that the duct burners will not be operated at "partial loads". The second combination used the maximum PM2.5 emissions from all "non-duct-burner" operating modes, combined with the worst-case MCL 59 °F stack parameters. The 24-hr PM2.5 SIA sensitivity results indicate that either of these worst case combinations result in model predicted concentrations below the SIL. Therefore, the conclusion that the Project 1-hr SO_2 and 24-hr PM2.5 impacts are below the SIL is not dependent upon use of the applicant's seasonally-varying emission and stack parameter methodology.

For the significant impact analysis of 1-hr NO_2 impacts, the combustion turbine emissions for the startup/shutdown operating scenario are almost an order of magnitude higher than normal operating emissions, therefore the 1-hr NO_2 SIA modeling only considered the startup/shutdown scenario. Once again, the applicant varied the stack parameters and emissions for the startup and shutdown scenario seasonally.

For the annual average significant impact analysis for SO_2, NO_2, PM10, and direct PM2.5 emissions, the combustion turbine annual emissions were modeled with "annual weighted average" stack parameters. The stack parameters were based on the representative annual average ambient temperature of 59 °F, and a weighted average of exit temperatures and exit velocities based on the number of hours during the year for each operating condition (i.e., turbine normal operation, duct firing, startup, and shutdown). ADEQ has performed additional sensitivity analyses to determine if the simple combination of worst-case stack parameters (MCL at 59 °F) with annual NO_X and PM2.5 emissions result in the same conclusions as the more complex "annual weighted average" stack parameter approach. The sensitivity results indicate these annual project impacts are below the SILs, therefore the conclusion that the Project annual NO_X and PM2.5 impacts are below the SILs is not dependent upon the use of applicant's "annual weighted average" stack parameter methodology.

Emissions and stack parameters in all modeling files were compared to data in the permit application and modeling report, and only minor discrepancies were found due to small rounding errors and the use of a higher annual NO_X emission rate for the auxiliary boiler in the modeling input file than in the emission calculations. Table 13 presents a summary of project emissions and stack parameters.

3. Modeling Results

a. Significant Impact Analysis

Table 14 presents results from the "project-only" significant impact analysis. The concentrations listed in this table are the highest concentration for all short-term and annual averages. (Because only one year of on-site data is used, no multi-year averaging is performed for PM2.5 or 1-hr SO_2 and NO_2 project impacts.) All modeled project impacts for CO, SO_2, annual NO_2, and PM10/PM2.5 were below the applicable SILs, and the background monitoring data presented in Table 12 demonstrates that the differences between the NAAQS and measured background concentrations are greater than the applicable SILs for all pollutants and averaging intervals. Therefore, the significant impact analysis demonstrates that the Project will not cause or contribute to a violation of the NAAQS and PSD increments for these pollutants and averaging periods. Cumulative modeling is required only for the 1-hour NO_2 NAAQS analysis.

Table 13. Source Emissions and Stack Parameters for Bowie Power Station Sources

Source ID	UTM Easting (m)	UTM Northing (m)	NO_X (lb/hr)	CO (lb/hr)	SO_2 (lb/hr)	PM10 (lb/hr)	PM2.5 (lb/hr)	Stack Ht (ft)	Temp (F)	Velocity (fps)	Diameter (ft)
Combustion Turbine 1	641514	3581844	101.3	262.3	4.10	8.5	8.5	180	180	43	18.0
Combustion Turbine 2	641515	3581798	101.3	262.3	4.10	8.5	8.5	180	180	43	18.0
Auxiliary Boiler	641489	3581909	0.55	1.85	0.11	0.17	0.17	44.9	300	50	2.5
Fire Pump	641544	3581919	1.26	0.81	0.003	0.011	0.011	35	997	214	0.42
Cooling Tower Cell 1	641500	3581956	NA	NA	NA	0.097	0.046	45.9	70	28.2	32.8
Cell 2	641515	3581956	NA	NA	NA	0.097	0.046	45.9	70	28.2	32.8
Cell 3	641530	3581956	NA	NA	NA	0.097	0.046	45.9	70	28.2	32.8
Cell 4	641545	3581956	NA	NA	NA	0.097	0.046	45.9	70	28.2	32.8
Cell 5	641560	3581956	NA	NA	NA	0.097	0.046	45.9	70	28.2	32.8
Cell 6	641574	3581956	NA	NA	NA	0.097	0.046	45.9	70	28.2	32.8
Cell 7	641589	3581956	NA	NA	NA	0.097	0.046	45.9	70	28.2	32.8
Cell 8	641604	3581956	NA	NA	NA	0.097	0.046	45.9	70	28.2	32.8
Cell 9	641619	3581956	NA	NA	NA	0.097	0.046	45.9	70	28.2	32.8

NOTES:
UTM = Universal Transverse Mercator
NA = Not Applicable
Stack parameters are for Minimum Compliance Load at 59 °F (equal to 50 percent load conditions).

All emissions are the maximum hourly emissions from any operating scenario, including startup/shutdown scenarios. The PM10 and PM2.5 emissions for the auxiliary boiler are based on the limitation of not more than 12 hours of operation per any calendar day. The PM10 and PM2.5 emissions for the fire pump are based on the limitation of not more than 4 hours of operation per any calendar day.

Table 14. Maximum Air Quality Impacts from Bowie Power Station Sources

Pollutant	Averaging Period	Maximum Project Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Maximum Distance of SIA (kilometers)
NO_2	1-hour	118	7.5	50
	Annual	0.2	1	NA
CO	1-hour	439	2000	NA
	8-hour	85	500	NA
SO_2	1-hour	5.2	7.8	NA
	3-hour	1.8	25	NA
	24-hour	0.4	5	NA
	Annual	0.06	1	NA
PM10	24-hour	1.8	5	NA
	Annual	0.3	1	NA
PM2.5	24-hour	1.07	1.2	NA
	Annual	0.16	0.3	NA

In addition to a direct PM2.5 impact analysis, the applicant performed a secondary PM2.5 impact analysis in accordance with U.S. EPA's *Draft Guidance for PM2.5 Permit Modeling*. According to this U.S. EPA guidance, the analysis of secondary PM2.5 formation may be completely qualitative in nature, may be based on a hybrid of qualitative and quantitative assessments, or may be a full quantitative photochemical grid modeling exercise (however, U.S. EPA anticipates only a few applications would require explicit photochemical grid modeling.) The applicant chose to perform both qualitative and quantitative assessments, using the AERMOD model for direct PM2.5 analyses and the CALPUFF model for secondary PM2.5 analyses. The qualitative assessment utilized speciated PM2.5 data from the Chiricahua National Monument monitoring station for 2009-2011 along with source apportionment analyses from the Western Regional Air Partnership (WRAP) Technical Support System. The conclusion of this qualitative analysis is that it is unlikely that a relatively small source of SO_2 and NO_X emissions such as the Bowie Power Station would appreciably increase PM2.5 background concentrations of ammonium sulfate and nitrate in the project area. The quantitative assessment used the same AERMOD analyses described above, along with CALPUFF modeling of the same two turbine operating scenarios used in the AERMOD analyses (100 percent load with duct burner and MCL load without duct burner, with seasonal variations of emissions and stack parameters) and the same receptor grid used in AERMOD. SO_2 emissions for the CALPUFF sulfate analysis were speciated using the National Park Service gas-turbine spreadsheet (http://www.nature.nps.gov/air/permits/ect/ectGasFiredCT.cfm).

The distances of the AERMOD-predicted maximum direct 24-hr PM2.5 impacts were compared to the distances of maximum CALPUFF-predicted secondary 24-hr PM2.5 impacts. The maximum direct PM2.5 impacts of approximately 1 $\mu g/m^3$ occur from 1 to 2 km from the turbine stacks, while the maximum secondary PM2.5 impacts of approximately 0.4 µg/m3 occur approximately 7 to 10 km downwind. This indicates that the direct and secondary PM2.5 impacts do not appreciably overlap, and that the close-in direct impacts are larger than the secondary impacts. The applicant then performed a complex analysis wherein receptor-by-receptor and hour-by-hour concentrations from both AERMOD and CALPUFF were combined. These results indicate that the maximum combined 24-hr PM2.5 impacts were only 0.01 $\mu g/m^3$ greater than the direct 24-hr PM2.5 impacts as determined by AERMOD, supporting the qualitative determination that the direct and secondary PM2.5 impacts do not appreciably overlap. Therefore, these qualitative and quantitative secondary PM2.5 impact analyses support the conclusion that the Project will not cause or contribute to a violation of the 24-hr and annual PM2.5 NAAQS and PSD Class II increments.

b. 1-hr NO_2 NAAQS Cumulative Source Inventory

ADEQ provided current NO_X emission data and stack parameters for Arizona sources within approximately 100 km of the Bowie Power Station, while the Air Quality Bureau of the New Mexico Environment Department provided data for sources in New Mexico within 110 km of Bowie. U.S. EPA's guidance document *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-Hour NO_2 National Ambient Air Quality Standard* discusses the concept of significant concentration gradient and notes 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." The U.S. EPA guidance suggests tools that can be used to inform a case-specific exercise of professional judgment to determine which sources should be explicitly modeled in a cumulative impact assessment. These tools include isopleth plots of project impacts, examination of impact patterns with respect to terrain, and the examination of the location of nearby sources and the background monitoring station relative to the project impact. ADEQ's modeling guidance suggests that an analysis of emissions versus distance is another appropriate tool for evaluating if sources are likely to have a significant impact in the project vicinity. The ADEQ guidance describes the "20D" methodology which is based on the relationship between source emission strength and impacts as a function of distance.

Based on U.S. EPA and ADEQ guidance, all identified sources within 10 km of the Bowie Power Station site were included in the cumulative modeling. Isopleth plots of the Project impacts were evaluated, and a "20D" analysis was used compile information on sources more distant than 10km from the Project impact area. (Note that the "20D" method was not used as a "bright line" to reject sources, but rather as supplemental information.) The applicant determined that the other sources to include in the cumulative 1-hr NO_2 emission inventory were the Apache Generating Station, the Pistachio Corporation of Arizona, and the El Paso Natural Gas Willcox and Bowie Compressor Stations. After review of the applicant's analyses, ADEQ concurs on the selection of these NO_X emission sources for the cumulative inventory.

c. Cumulative Impact Analysis

The cumulative 1-hr NO_2 NAAQS analysis was run with a subset of receptors for which the Project had significant 1-hr NO_2 impacts. (This reduced the number of receptors from 6,193 to 3,701.) Background NO_2 concentrations that vary by season and hour of the day were input to AERMOD, as well as seasonally varying NO_X emissions and stack parameters for the Bowie combustion turbines (based on the worst-case startup operating scenario). The maximum model predicted cumulative 1-hour NO_2 design concentration, including background, was 252.3 $\mu g/m^3$. The 1-hour NO_2 NAAQS is 188.7 $\mu g/m^3$, and there were a total of sixteen hours that were predicted to exceed the NAAQS. The largest contribution by the Bowie Power Station to any of the modeled exceedances, as determined using the MAXDCON option in AERMOD, was 0.068 $\mu g/m^3$, which is well below the 1-hr NO_2 SIL of 7.5 $\mu g/m^3$. Therefore, the cumulative 1-hr NO_2 NAAQS analysis demonstrates that the Project will not cause or contribute to a violation of the 1-hr NO_2 NAAQS.

B. Additional Impacts Analysis

1. Growth Analysis

The applicant has estimated that approximately 25 permanent new positions will be needed for operation of the new facility. It is anticipated that the personnel hired and involved in the construction phase of the project would be drawn, in large part, from the surrounding communities, as would some of the operations personnel. As such, no significant increase in air pollutant emissions indirectly associated with the proposed project is expected to occur. Therefore, the potential of additional industrial, commercial, and residential growth from this facility will be limited. The Department concurs with the applicant's analysis.

2. Soils and Vegetation Impacts Analysis

A.A.C. R18-2-407.I.1 requires that the PSD permit application include in the permit application an analysis of the impacts that emissions from proposed facility and from secondary growth will have on soils and vegetation. The applicant inventoried soil and vegetation resources in the project vicinity, and identified available effects threshold studies including U.S. EPA's *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals*, EPA-450/2-81-078. When the model-predicted criteria pollutant and trace metals concentrations are compared to screening thresholds found in the literature, none of the screening thresholds are approached in magnitude. Therefore, the analysis indicates that the project will not adversely impact soils and vegetation in the area.

3. Visibility Impacts Analysis

A.A.C. R18-2-407.I.1 and R18-2-410 require that the PSD permit application include an analysis of the impacts that emissions from proposed facility and from secondary growth will have on visibility. This requirement is separate from any Class I visibility impact analysis. The visibility analysis was conducted for the Fort Bowie National Historic Site. The nearest edge of this historic site is located approximately 23 km to the south-southeast of the proposed project location. A visibility screening analyses using the VISCREEN model was performed.

To determine the Level II dispersion conditions, the meteorological data was sorted by wind direction so that only those wind directions that could reasonably transport plumes toward the study area are examined. Those periods are then divided into four, 6-hour daily time periods (the local hours of 1-6, 7-12, 13-18, and 19-24). As described in U.S. EPA's "Workbook for Plume Visual Impact Screening and Analysis," the worst-case meteorological condition is defined as the combination of stability class and wind speed with a cumulative probability of 1 percent. For each of the defined time periods, the cumulative frequency of occurrence of the 16 VISCREEN meteorological conditions was calculated and the condition that represented 1 percent of the values processed was determined. The most restrictive of the 1 percent values, a stability class of E (5) and a wind speed of 2-3 m/sec, was then used in the Level II analysis.

Visibility effects thresholds have not been established for Class II areas, therefore the Class II impacts are typically compared against Class I thresholds. The Class II visibility analysis results for the Fort Bowie National Historic Site are presented in the permit application, and indicate that perceptible plumes may occur inside the Class II area under certain conditions.

4. Class I Area Impacts Analysis

When emissions from a proposed PSD project may impact a Class I area, the permitting authority must notify the FLM for the Class I area in question. In addition, two types of air quality impact analyses are typically required, a Class I increment analysis and an Air Quality Related Values (AQRV) analysis. These analyses were performed for those pollutants for which the project has emission rates above the PSD significant emission levels, NO_2, PM2.5, and PM10 (there are no Class I increments or AQRVs associated with CO emissions).

The proposed project site is located within 300 km of ten Class I areas. The FLMs for these Class I areas include the National Park Service and the U.S. Forest Service. ADEQ has notified and consulted with these FLMs during the review of the applicant's Class I impact analyses.

The 2010 Revised *Federal Land Managers' Air Quality Related Values Work Group* (FLAG) Class I modeling guidance presents recommendations for conducting Class I AQRV analyses. This guidance establishes a screening method for determining when AQRV analyses are not required. Specifically, if the SO_2, NO_X, PM10, and sulfuric acid mist emissions (Q in units of tpy) divided by distance (D in units of km) are less than < 10, then presumptively there is no adverse impact and no Class I AQRV analysis is required. Applying this to the annualized aggregate Project emission rate indicates that for any Class I area beyond approximately 30 km, AQRV impacts from the proposed project are unlikely. However, this AQRV screening guidance does not apply to the Class I PSD increment analysis. Consequently, based on ADEQ recommendations to perform Class I increment modeling at all Class I areas within 300 km, the applicant performed CALPUFF modeling for both Class I increments and AQRVs at nine of the ten Class I areas (the Chiricahua NM lies completely within 50 km of the project site, therefore AERMOD was used to predict near-field Class I increment impacts, VISCREEN was used to evaluate visibility impacts, and CALPUFF was only used to evaluate deposition impacts at this Class I area).

The Class I analyses used the most recent U.S. EPA-approved version of the CALPUFF model, version 5.8.4. The CALMET processor version 5.8.4 was run using MM5 data sets (the 2001 EPA 36 km MM5 set, the 2002 Western Regional

Air Partnership (WRAP) 12 km MM5 set, and the 2003 Midwest Regional Planning Organization (MRPO) 36 km MM5 set). In addition, four surface meteorological stations (DUG, SAD, SUC, and TUS), one upper air station (TUS), and 11 precipitation stations were used. The Lambert Conformal Coordinate projected domain consists of 127 NX grid cells and 92 NY grid cells spaced 4 km apart, in accordance with U.S. EPA guidance. The CALMET data were processed using the U.S. EPA recommended switch settings (Tyler Fox, August 31, 2009, Memorandum: "Clarification on EPA-FLM Recommended Settings for CALMET"). The CALPUFF results were post-processed with CALPOST version 6.221. All CALPOST switch settings conformed to regulatory guidance and FLAG recommendations.

The emissions modeled with CALPUFF for 24-hr Class I significant impact analyses were based on the same two turbine operating scenarios used for the AERMOD 24-hr significant impact analysis (100 percent load with duct burner and MCL load without duct burner, and the emissions and stack parameters were varied seasonally). Similarly, the same annual emissions and stack parameters were used for the annual Class I significant impact analyses. An additional a 24-hr emission scenario was developed for 24-hr visibility impact analyses that addressed the higher NOx emissions during startup (a 24-hour operating scenario that included three hot starts and two shutdowns for each turbine/duct burner pair, with maximum normal operation emissions for the rest of the 24-hour period). The stack parameters for this last scenario were the weighted average of the temperatures and flow rates for the various operating modes. For the visibility modeling, the SO_2 and PM emissions were speciated using the National Park Service gas-turbine spreadsheet. For the PM10 and PM2.5 Class I significant impact analysis, the PM10 and PM2.5 emissions were not speciated and were directly modeled in CALPUFF as PMF species; in addition, NOx emissions were included as secondary PM2.5 emissions (SO2 emissions were not included in the secondary PM2.5 analysis because they are below the Significant Emission Rate).

The Class I significant impact analysis results for NO_2, PM2.5, and PM10 are listed in Table 15, and are compared to the Class I SILs. All impacts are below the relevant SILs, with the exception of the 24-hour PM2.5 impacts at Chiricahua WA which slightly exceeded the Class I SIL for a single day and receptor in 2003. As discussed by U.S. EPA in *Guidance for PM2.5 Permit Modeling*, May 2014, since the PM2.5 trigger date has only recently been established (i.e., October 20, 2011), a new PSD source will often be the first source with PM2.5 increment-consuming emissions in the area. Under this situation, a permitting authority may have sufficient reason to conclude that the impacts of the new source may be compared directly to the allowable increments, without the need for a cumulative modeling analysis (such a situation would involve the new source being the first PSD application in the area after the trigger date, which establishes the minor source baseline date and baseline area, and confirmation that no relevant major source construction has already occurred since the major source baseline date).

Table 15. PSD Class I Significant Impact Analysis

Pollutant	Averaging Period	Class I Increment $\mu g/m^3$	Class I SIL $\mu g/m^3$	Maximum Project Impact at any Class I Area $\mu g/m^3$
NO_X	Annual	2.5	0.1	0.01
PM10	24-hour	8	0.3	0.076
	Annual	4	0.2	0.005
PM2.5	24-hour	2	0.07	0.076
	Annual	1	0.06	0.006

ADEQ has evaluated the permitting activities since October 2011 within 300 km of the Chiricahua WA, including discussions with and data review from other permitting agencies (including Pinal and Maricopa Counties and New Mexico). ADEQ has determined that the Bowie PSD permit application is the first PSD permit application for a project with significant PM2.5 emissions and a significant 24-hr PM2.5 impact in the Chiricahua WA, therefore it triggers the minor source baseline date for the Chiricahua WA Class I area. ADEQ has also confirmed that no relevant major source construction has occurred within 300 km of the Chiricahua WA Class I area, with the exception of the El Paso Natural Gas Company Willcox Compressor Station near Willcox, Arizona. However, that project only triggered PSD review for NOx emissions, and the Class I impact analysis demonstrated that the NOx impacts were insignificant. Therefore, ADEQ has concluded that the Bowie Power Station Class I 24-hr PM2.5 maximum impact of 0.076 $\mu g/m^3$ may be compared directly to the allowable Class I increment of 2 $\mu g/m^3$, without the need for a cumulative modeling analysis. The CALPUFF predicted impact is only 4% of the increment, and the analysis demonstrates there will not be an exceedance of the 24-hr Class I PM2.5 increment.

The CALPUFF model was also used to estimate nitrogen deposition within the Class I areas. CALPOST was used to calculate annual aggregate species values, which were compared to the NPS Deposition Analysis Thresholds (DATs) for the western United States of 0.005 kilograms per hectare per year. All project impacts are below the DAT thresholds, indicating the project should not cause adverse deposition effects.

The results from the CALPUFF visibility assessment are expressed as the percent change in light extinction, compared to natural background visibility levels. In general the FLM considers 98th percentile impacts of 5% or less to be insignificant, and 10% or greater to be potentially adverse. Using CALPOST Method 8, all CALPUFF predicted 98th percentile visibility impacts are below the 5% threshold. The Chiricahua NM Class I area visibility analysis was performed using a Level II VISCREEN methodology, and the project visibility effects do not exceed the visual screening criteria for this Class I area.

XII. INSIGNIFICANT ACTIVITIES

Table 10 shows the pollutant-emitting activities at the Bowie Power Station that are classified as insignificant activities due to their size.

Table 10: Insignificant Activities

Equipment Description	Number of Equipment Items	Maximum Capacity	Verification of Insignificance
Diesel Storage Tank	1	500 gallons	A.A.C. R18-2-101.68.a.i.
Lube Oil Storage Tanks	10	2,000 gallons	A.A.C. R18-2-101.68.a.i.

XIII. LIST OF ABBREVIATIONS, ACRONYMS, AND CHEMICAL FORMULAE

A.A.C. .... Arizona Administrative Code
ADEQ .... Arizona Department of Environmental Quality
AERMOD .... AMS/EPA Regulatory Model
AERMET .... AERMOD Meteorological Preprocessor
AMS .... American Meteorological Society
AQD .... Air Quality Division
AQRV .... Air Quality Related Values
ARM .... Ambient Ratio Method
A.R.S. .... Arizona Revised Statutes
BACT .... Best Available Control Technology
Btu/ft^3 .... British Thermal Units per Cubic Foot
CAM .... Compliance Assurance Monitoring
CAPCOA .... California Air Pollution Control Officers Association
CEMS .... Continuous Emissions Monitoring System
CFR .... Code of Federal Regulations
CH_4 .... Methane
CO .... Carbon Monoxide
CO_2 .... Carbon Dioxide
CO_2e .... CO_2 equivalent basis
CTG. .... Combustion Turbine Generator
DLN .... Dry Low-NO_X
EPA .... Environmental Protection Agency
FERC .... Federal Energy Regulatory Commission
FLAG .... Federal Land Managers' Air Quality Related Values Work Group
FLM .... Federal Land Manager
°F .... degrees Fahrenheit
ft .... Feet
g .... Gram

gal .... Gallon
GE .... General Electric
GHG .... Greenhouse Gases
HAP .... Hazardous Air Pollutant
HHV .... Higher Heating Value
hp .... Horsepower
hr .... Hour
HRSG .... Heat Recovery Steam Generator
IC .... Internal Combustion
kV .... Kilovolt
kW .... Kilowatt
lb .... Pound
m .... Meter
MCL .... Minimum Compliance Load
min .... Minute
MMBtu .... Million British Thermal Units
$\mu g/m^3$ .... Microgram per Cubic Meter
MMCFD .... Million Cubic Feet per Day
MW .... Megawatts
NAAQS .... National Ambient Air Quality Standard
NFPA .... National Fire Protection Association
NH_3 .... Ammonia
NO_X .... Nitrogen Oxides
NO_2 .... Nitrogen Dioxide
N_2O .... Nitrous Oxide
NSPS .... New Source Performance Standards
O_3 .... Ozone
Pb .... Lead
PLUVUE II .... Plume Visibility Model
PM .... Particulate Matter
PM10 .... Particulate Matter less than 10 µm nominal aerodynamic diameter
PM2.5 .... Particulate Matter less than 2.5 µm nominal aerodynamic diameter
PSD .... Prevention of Significant Deterioration
psia .... Pounds per square Inch (absolute)
PTE .... Potential to Emit
PVMRM .... Plume Volume Molar Ratio Method
SCR .... Selective Catalytic Reduction
sec .... Seconds
SF_6 .... Sulfur Hexafluoride
SIA .... Significant Impact Area
SIL .... Significant Impact Level
SO_2 .... Sulfur Dioxide Significant Impact Levels
TPY .... Tons per Year
U.S. .... United States
VISCREEN .... Plume Visual Impact Screening Model
VOC .... Volatile Organic Compound
yr .... Year