

# ADEQ DRAFT OPERATING AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation 26:

Permit No. : 1903-AOP-R7

IS ISSUED TO:

AECI - Dell Power Plant  
301 E. Hwy 18  
Dell, AR 72426  
Mississippi County  
AFIN: 47-00448

THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

AND

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

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Mike Bates  
Chief, Air Division

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Date

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APPENDIX A

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APPENDIX B

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#### List of Acronyms and Abbreviations

A.C.A.	Arkansas Code Annotated
AFIN	ADEQ Facility Identification Number
CFR	Code of Federal Regulations
CO	Carbon Monoxide
HAP	Hazardous Air Pollutant
lb/hr	Pound Per Hour
MVAC	Motor Vehicle Air Conditioner
NAAQS	National Ambient Air Quality Standard
No.	Number
NO <sub>x</sub>	Nitrogen Oxide
PM	Particulate Matter
PM <sub>10</sub>	Particulate Matter Smaller Than Ten Microns
SNAP	Significant New Alternatives Program (SNAP)
SO <sub>2</sub>	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

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## SECTION I: FACILITY INFORMATION

PERMITTEE: AECI - Dell Power Plant

AFIN: 47-00448

PERMIT NUMBER: 1903-AOP-R7

FACILITY ADDRESS: 301 E. Hwy 18  
Dell, AR 72426

MAILING ADDRESS: 301 E Hwy 18  
Dell, AR 72426

COUNTY: Mississippi County

CONTACT NAME: Tadd Henry

CONTACT POSITION: Environmental Engineer

TELEPHONE NUMBER: 417-885-9222

REVIEWING ENGINEER: Charles Hurt, P.E.

UTM North South (Y): Zone 15: 3972883.78 m

UTM East West (X): Zone 15: 768626.70 m

## SECTION II: INTRODUCTION

### Summary of Permit Activity

Associated Electric Cooperative, Inc. – Dell Power Plant (AFIN: 47-00448) owns and operates a power plant located at 301 Highway 18 East in Dell, Arkansas 72426. AECI submitted a Title V renewal application with modifications. The permit modification includes firing No. 2 fuel oil for up to 1,850 hours per year and installing two 1.75 million gallon fuel oil storage tanks and one 2.7 million gallon demineralized water storage tank (not a source of air emissions). The emissions associated with the physical modifications are discussed later with the PSD applicability.

This modification also revises Specific Condition #27 (b) to account for the combustion process differences between operating on natural gas versus fuel oil. While burning natural gas the combustion turbines cycle through multiple staging modes prior to reaching full load premix operation. Whereas, liquid fuel is burned in a diffusion type flame without staging modes.

This modification also revises Specific Condition #41 to allow use of a handheld meter and to reduce the sampling frequency from weekly to monthly for total dissolved solids for SN-04 through SN-15. The use of the handheld meter will result in a significant reduction in time and cost in demonstrating compliance. Data accompanied the request which indicates compliance can be demonstrated with monthly sampling.

This modification also removes the waste water cooling tower (SN-28 through SN-31) and four (4.05 MMBtu/hr each) fuel gas heaters (insignificant activities) from the permit. The waste water cooling tower was never built, and AECI has no future plans to install the waste water cooling tower. The four fuel gas heaters do not exist. The only fuel gas heaters at the facility are SN-32 and SN-33.

Overall, the permitted increase was 84.5 tpy PM, 90.7 tpy PM<sub>10</sub>, 6.64 tpy SO<sub>2</sub>, 68.5 tpy CO, 98.3 tpy NO<sub>x</sub>, and 0.21 tpy Lead. Permitted VOC decreased by 23.6 tpy.

### Prevention of Significant Deterioration

This facility is considered an existing major source under 40 CFR §52.21, *Prevention of Significant Deterioration* (PSD) regulations because the facility is a fossil fuel fired steam electric plant and has the potential to emit more than 100 tpy of any single NSR pollutant. The following BACT analysis pertains to No. 2 fuel oil firing, and the limits for natural gas firing are not changing.

#### Modification PSD Applicability

The emission increase associated with the physical modifications is presented below and is based on past actual and future potential emissions. The past actual emissions are zero because the

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combustion turbines have operated for less than two years. The future potential emissions are the potential to emit based on calculations submitted by the permittee.

Source	Emission Rate (tpy)					
	PM <sub>10</sub>	SO <sub>2</sub>	VOC	CO	NO <sub>x</sub>	Lead
Combustion Turbine	33.21	2.97	6.18	49.04	48.33	0.03
Combustion Turbine	33.21	2.97	6.18	49.04	48.33	0.03
Diesel Storage Tank #1	-	-	1.02	-	-	-
Diesel Storage Tank #2	-	-	1.02	-	-	-
Total	66.42	5.94	14.40	98.08	96.66	0.06
PSD Significant Emission Rate	15	40	40	100	40	0.6
Is Netting Required?	Yes	No	No	No	Yes	No

No further consideration is given to SO<sub>2</sub>, VOC, CO or Lead because the increase in the emission rates for those pollutants does not exceed significant emission rates (SER). Since the emission increase associated with the modification exceeds the SER for PM<sub>10</sub> and NO<sub>x</sub>, the contemporaneous changes must be considered in determining whether or not PSD review is triggered. Only one contemporaneous change was identified during the contemporaneous period. On July 18, 2006 Permit No. 1903-AOP-R4 was issued to increase the hours of operation for the auxiliary boiler (SN-03) to 8,760 hours per year.

Source	Emission Rate (tpy)	
	PM <sub>10</sub>	NO <sub>x</sub>
Auxiliary Boiler	2.71	17.82
Net Change	69.13	114.48
PSD Significant Emission Rate	15	40
Subject to PSD Review?	Yes	Yes

The net emission increase exceeded the PSD SER for PM<sub>10</sub> and NO<sub>x</sub>. Therefore, PSD review was triggered for those pollutants.

### BACT Analysis Summary

Any major source or major modification subject to PSD review must conduct an analysis to ensure the use of best available control technology (BACT). The requirements for conducting BACT can be found in the PSD regulations. A BACT analysis is required for each new or physically modified emission unit for each pollutant that exceeds an applicable PSD SER. For this modification PM<sub>10</sub> and NO<sub>x</sub> exceed their respective SER. The emission units and pollutants that require BACT are listed below.

Emission Unit	Source Description	Pollutants Subject to BACT
SN-01	Combustion Turbine and HRSG	PM <sub>10</sub> and NO <sub>x</sub>
SN-02	Combustion Turbine and HRSG	PM <sub>10</sub> and NO <sub>x</sub>

The methodology used to determine BACT is the top-down method described in a 1987 memorandum from the EPA Assistant Administrator for Air and Radiation. Following the top-down method all available control technologies are ranked in descending order of control effectiveness. The most stringent control available for a similar or identical source or source category is identified, and a determination of feasibility is made. If the most stringent level of control is determined to be infeasible based on technical, economic, environmental, or energy related reasons, then the next most stringent option is evaluated. The process continues until the BACT level under consideration cannot be eliminated. The *New Source Review Workshop Manual (Draft)* lists the five basic steps of the method.

*BACT Evaluation for the Combustion Turbines (SN-01 and SN-02)*

*Step 1. Identify All Control Technologies.* - The following technologies were considered for the turbines:

Pollutant	Control Technology for Combustion Turbines
NO <sub>x</sub>	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Catalytic Absorption Catalytic Combustion Dry Low NO <sub>x</sub> Burners (LNB) Water/Steam Injection
PM <sub>10</sub> (Filterable)	Clean/Low Sulfur Fuels Good Combustion Practices (GCP)

*Step 2. Eliminate Technically Infeasible Control Technologies* - The second step is to determine which control technologies are infeasible for technical reasons. Each control technologies for each pollutant is considered, those that are clearly technically infeasible are eliminated.

Selective Non-Catalytic Reduction was determined to be infeasible because of the high gas velocity from the turbines (i.e. SNCR requires more residence time), and the reaction that results in lower NO<sub>x</sub> concentrations occurs between 1600 °F and 2200 °F. The temperature of the exhaust gases are generally around 1300 °F. SNCR is not listed in the RACT/BACT/LAER Clearinghouse (RBLC) for large combustion turbines.

Catalytic Absorption and Catalytic Combustion were determined to be technically infeasible because those control technologies have not been demonstrated for large combustion turbines. Catalytic combustion control was attempted at one facility, Pastoria Energy, Bakersfield, CA but did not scale-up for the design requirements. It was replaced with SCR. Catalytic Absorption and Catalytic Combustion are not listed in the RBLC for large combustion turbines.

The technically feasible control technologies for NO<sub>x</sub> are LNB, steam/water injection, and SCR, and the control technologies for PM<sub>10</sub> are all of the technologies listed above.

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*Step 3. Rank Remaining Control Technologies* – The third step is to rank the remaining control technologies based on effectiveness.

For PM<sub>10</sub> both remaining control technologies will be employed. Therefore, ranking is not necessary for PM<sub>10</sub>.

For NO<sub>x</sub> all three remaining control technologies will be employed.

*Step 4. Top Down Evaluation of Control Options* - The fourth step is to evaluate the remaining control technologies based on economic, energy, and environmental considerations.

For PM<sub>10</sub> and NO<sub>x</sub> the remaining control technologies will be employed. Therefore, evaluation of control options is not necessary for PM<sub>10</sub> or NO<sub>x</sub>.

*Step 5. Select BACT* – The most effective control option not eliminated is BACT. Based on available information in the RACT/BACT/LAER Clearinghouse, publications from EPA’s Clean Air, Technology Center, EPA’s National Combustion Turbine Spreadsheet, and BACT determinations for oil fired combined cycle plants, BACT limits were determined to be:

Sources	Pollutant	BACT Determination <sup>(a)</sup>		
Each 7FA Combustion Turbine / HRSG with and without Duct Burners (SN-01 and SN-02) in No. 2 Fuel Oil Service	PM <sub>10</sub>	Use of clean fuel <sup>(b)</sup> and good combustion practice <sup>(c)</sup>	0.009 lb/MMBtu	Stack Testing (3-hour average) and Fuel Monitoring
	NO <sub>x</sub>	Dry Low NO <sub>x</sub> Burners Water Injection SCR	6 ppmvd @ 15 % O <sub>2</sub>	3-hour average (CEMS)
	Visible Emissions	Use of clean fuel and good combustion practices	10%	Method 9 Observations

- a. BACT Determination is valid only up to 1,850 hours per year per turbine on fuel oil.
- b. Clean fuel is No. 2 fuel oil which contains 0.0015 percent by weight of sulfur or less.
- c. "Good combustion practices" are taken to mean (1) the turbines shall be operated in a manner to achieve maximum thermal efficiency via operating only at high loads (e.g., greater than 60 percent of the power output capacity) to the extent possible, (2) the best available combustion fuel oil system for the existing turbines shall be installed and tuned properly to ensure complete (as possible) combustion.

Class II Area Ambient Air Impact Analysis

*Air Quality Analysis*

Since the total facility-wide emissions exceed the PSD SER for NO<sub>x</sub> and PM<sub>10</sub> an air quality analysis is required to demonstrate that these emissions do not cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS) or exceed a PSD increment. The air quality analysis consists of a preliminary analysis and where warranted a full impact analysis.

*Preliminary Analysis*

The preliminary analysis determines whether the applicant can forego further air quality analyses for a particular pollutant; may allow the applicant to be exempted from the ambient monitoring data requirements; and is used to define the impact area within which a full impact analysis must be carried out. The preliminary analysis models only the significant increase in potential emissions of a pollutant from a proposed new source, or the significant net emissions increase of a pollutant from a proposed modification.

For PSD permits, a full ambient air impact analysis is required for each pollutant from which the net emission increase will result in an ambient impact over the predetermined level. This level is known as the “significant impact level” (SIL). The following table shows the results of the preliminary analysis. A full impact analysis is not required for a particular pollutant when emissions of that pollutant from a proposed source or modification would not increase ambient concentrations by more than prescribed significant ambient impact levels. Therefore, no further consideration is given to PM<sub>10</sub> (annual) CO, and NO<sub>x</sub>. A full impact analysis was required for 24-hour averaging period for PM<sub>10</sub>.

Pollutant	Averaging Period	Year of Maximum Impact	Maximum Modeled Concentration (µg/m <sup>3</sup> )	Significant impact Level (µg/m <sup>3</sup> )
PM <sub>10</sub>	24-hour	2006	8.82	5
	Annual	2006	0.51	1
NO <sub>2</sub>	Annual	2008	0.91*	1

\* The modeled concentration is based on the default ambient ratio NO<sub>2</sub>/NO<sub>x</sub> of 0.75.

*Full Impact Analysis*

A full impact analysis is required for any pollutant for which the proposed source's estimated ambient pollutant concentrations exceed prescribed significant ambient impact levels. The preliminary analysis above indicates a full impact analysis for the PM<sub>10</sub> 24-hour averaging period. Only the receptors with in the area of impact (AOI) are evaluated in the full impact analysis. Impacts exceeding the PM<sub>10</sub> 24-hour SIL extend out to 978 m. Therefore, the AOI was defined as circular area with a radius of 1 km.

The full impact analysis consists of a NAAQS analysis and increment consumption analysis. For the NAAQS analysis, emissions from the facility were based on the PTE. To estimate the total concentration, the modeled impacts from the facility and nearby facilities (inventory sources with in 50 km plus radius of impact) were added to the background concentration determined based on ambient monitoring data.

Pollutant	Averaging Period	Year of Maximum Impact	Modeled Concentration <sup>(a)</sup> ( $\mu\text{g}/\text{m}^3$ )	Total Concentration <sup>(b)</sup> ( $\mu\text{g}/\text{m}^3$ )	NAAQS ( $\mu\text{g}/\text{m}^3$ )
PM <sub>10</sub>	24-hour	2004	16.79 <sup>(c)</sup>	80.79	150

- a. Modeled concentration is the impact from the source and inventory sources.
- b. Total concentration is the impact from the source, inventory sources, and the Little Rock PM<sub>10</sub> monitor.
- c. High 6<sup>th</sup> High 24-Hour modeled concentration

For the increment analysis the maximum 24-hour 2<sup>nd</sup> highest modeled impact is compared to the 24-hour increment. Regulation No. §19.904 (C)(1) requires further analysis if more than 80% of a short term increment is consumed. The table below indicates the modeled impacts are less than the increment and that no further analysis is required.

Pollutant	Averaging Period	Year of Maximum Impact	Modeled Concentration <sup>(a)</sup> ( $\mu\text{g}/\text{m}^3$ )	PSD Increment ( $\mu\text{g}/\text{m}^3$ )	80% of PSD Increment ( $\mu\text{g}/\text{m}^3$ )
PM <sub>10</sub>	24-hour	2008	17.97	39	31.2

- a. Modeled concentration is the impact from the source and inventory sources.

### Class II Area Additional Impacts Analysis

An additional impact analysis is based existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the project's area of impact. The additional impact analysis consists of three parts: (1) growth, (2) soils and vegetation, and (3) visibility impairment.

#### *Growth Analysis*

The growth analysis includes a projection of the associated industrial, commercial, and residential source growth that result in the area due to the source and an estimate of the air emissions generated by the above associated industrial, commercial, and residential growth. The project is not expected to create any new fulltime positions. Residential growth is not expected to result from the project. In addition, the shipping of raw materials and products to and from the facility is not expected to significantly increase the level of rail or ground traffic in the area. Therefore, no appreciable increase in emissions is expected as a result of any industrial, commercial, or residential growth associated with the project.

#### *Soils and Vegetation*

The analysis of soil and vegetation air pollution impacts is based on an inventory of the soil and vegetation types found in the impact area. This inventory considers vegetation with commercial or recreational value. The Mississippi County area consists mainly of farmland. The primary crops present in the area include rice, sorghum, wheat, com, cotton, and soybeans. The secondary NAAQS, which establish the ambient concentration levels below which no harmful effects to either soil or vegetation can be expected, are used as indicators of potentially adverse

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impacts. Thus, the modeled impacts, all of which are below the applicable secondary NAAQS, presumptively show that there will be no adverse impact upon either soil or vegetation due to the proposed project.

*Class II Area Visibility*

A screening analysis of predicted impacts on visibility was performed. Visibility was evaluated using VISCREEN. The results from VISCREEN predicted that the light extinction and change in contrast were below the first level of screening (i.e.  $\Delta E \leq 2.0$  and  $C_p \leq 0.05$ ). Therefore, it is presumed the project will not have an adverse impact.

Class I Area Impact Analysis

Class I areas are areas of special national or regional natural, scenic, recreational, or historic value for which the PSD regulations provide special protection. The nearest Class I area is the Mingo National Wildlife Refuge (NWR), which is approximately 120 km from the Dell Power Plant site.

A screening analysis of predicted impacts on Class I increments and visibility was performed. Visibility was evaluated using VISCREEN. The results from VISCREEN predicted that the light extinction and change in contrast were below the first level of screening (i.e.  $\Delta E \leq 2.0$  and  $C_p \leq 0.05$ ).

The Class I increment assessment was performed utilizing AERMOD analyses using a single-ring polar receptor grid, with receptors located at five-degree increments, 50 km from the center of the facility. The emissions associated with the proposed project for PM<sub>10</sub> and NO<sub>x</sub> were modeled and the results compared to the Class I SILs. As shown below, the modeling results are below the applicable Class I Increments and SILs for these pollutants. Therefore, it is presumed the project will not have an adverse impact on Class I increments.

	24-Hour PM <sub>10</sub> ( $\mu\text{g}/\text{m}^3$ )	Annual PM <sub>10</sub> ( $\mu\text{g}/\text{m}^3$ )	Annual NO <sub>x</sub> ( $\mu\text{g}/\text{m}^3$ )
Maximum Impact	0.1889	0.0130	0.0086
Class I Area Increment	10	5	2.5
Class I Area SIL	0.3	0.2	0.1

**Process Description**

This TPS facility is comprised of two GE S207FA combustion turbine-generators; two heat recovery steam generators (HRSG) configured for enhanced thermal efficiency; and steam turbine-generating equipment (SN-01 and SN-02). Additional emission generating equipment includes an auxiliary boiler (SN-03), an emergency generator (SN-23), a diesel fired fire pump (insignificant), a cooling tower system (SN-04 through SN-15), an inlet cooling system (SN-16 through SN-27) consisting of three, four-cell mechanical draft cooling towers and a four cell wastewater cooling tower (SN-28 through SN-31). In order to reduce nitrogen oxide (NO<sub>x</sub>)

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emissions for the facility and meet Arkansas emission guidelines, the facility utilizes Selective Catalytic Reduction (SCR) for the combustion turbine-generators.

### Regulations

The following table contains the regulations applicable to this permit.

Regulations
<i>Arkansas Air Pollution Control Code, Regulation 18, effective January 25, 2009</i>
<i>Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Regulation 19, effective July 18, 2009</i>
<i>Regulations of the Arkansas Operating Air Permit Program, Regulation 26, effective January 25, 2009</i>
<i>40 CFR Part 52.21 – Prevention of Significant Deterioration of Air Quality</i>
<i>40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units</i>
<i>40 CFR Part 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines</i>
<i>40 CFR Part 63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines</i>
<i>40 CFR Parts 72, 73, 75, and 76 - Acid Rain Program</i>
<i>40 CFR Part 97 - Clean Air Interstate Rule</i>
<i>40 CFR Part 82 - Stratospheric Ozone Protection</i>

### Emission Summary

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	104.3	392.4
		PM <sub>10</sub>	100.9	298.5
		SO <sub>2</sub>	9.7	42.1
		VOC	107.4	82.5
		CO	230.6	623.6
		NO <sub>x</sub>	132.2	392.1
		Lead	0.31	0.51
HAPs*		1,3-Butadiene	0.09	0.11
		Acetaldehyde	0.17	0.81
		Acrolein	0.05	0.13
		Arsenic	0.07	0.09
		Benzene	0.26	0.44
		Beryllium	0.03	0.05
		Cadmium	0.03	0.05
		Chromium	0.07	0.09
		Cobalt	0.03	0.05
		Dichlorobenzene	0.03	0.05
		Ethyl benzene	0.14	0.60
		Formaldehyde	2.82	13.38
		Hexane	1.40	6.96
		Manganese	3.35	3.11
		Mercury	0.03	0.05
		Naphthalene	0.16	0.20
		Nickel	0.02	0.04
		PAH	0.17	0.21
		Phenanthrene	0.01	0.01
		POM	0.01	0.01
	Propylene oxide	0.12	0.50	
	Selenium	0.11	0.13	
	Toluene	0.62	2.24	
	Xylene	0.41	1.21	
Air Contaminants **		Ammonia	49.20	215.4

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EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-01	East Side Combustion Turbine/HRSG Stack (Natural Gas)	PM	32.0	140.2
		PM <sub>10</sub>	23.0	100.7
		SO <sub>2</sub>	4.0	17.5
		VOC	6.4	28.0
		CO	56.0	245.3
		NO <sub>x</sub>	30.0	131.4
		Lead	0.10	0.10
		1,3-Butadiene	0.01	0.01
		Acetaldehyde	0.08	0.40
		Acrolein	0.02	0.06
		Ammonia	24.60	107.70***
		Arsenic	0.01	0.01
		Benzene	0.03	0.10
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Chromium	0.01	0.01
		Cobalt	0.01	0.01
		Dichlorobenzene	0.01	0.01
		Ethyl benzene	0.07	0.30
		Formaldehyde	1.40	6.10
		Hexane	0.60	2.60
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene	0.01	0.02
		Nickel	0.01	0.01
		PAH	0.01	0.02
		Propylene oxide	0.06	0.25
		Selenium	0.01	0.01
Toluene	0.30	1.10		
Xylene	0.20	0.60		

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EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-01	East Side Combustion Turbine/HRSG Stack (No. 2 Fuel Oil)	PM	48.9	45.2
		PM <sub>10</sub>	48.9	45.2
		SO <sub>2</sub>	3.4	3.2
		VOC	11.6	10.7
		CO	53.1	49.1
		NO <sub>x</sub>	52.3	48.4
		Lead	0.10	0.10
		1,3-Butadiene	0.04	0.04
		Ammonia	24.60	107.7***
		Arsenic	0.03	0.03
		Benzene	0.12	0.11
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Chromium	0.03	0.03
		Cobalt	0.01	0.01
		Dichlorobenzene	0.01	0.01
		Formaldehyde	0.62	0.57
		Hexane	0.57	0.53
		Manganese	1.67	1.54
		Mercury	0.01	0.01
Naphthalene	0.07	0.07		
Nickel	0.01	0.01		
PAH	0.08	0.08		
Selenium	0.05	0.05		
Toluene	0.01	0.01		

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EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-02	West Side Combustion Turbine/HRSG Stack (Natural Gas)	PM	32.0	140.2
		PM <sub>10</sub>	23.0	100.7
		SO <sub>2</sub>	4.0	17.5
		VOC	6.4	28.0
		CO	56.0	245.3
		NO <sub>x</sub>	30.0	131.4
		Lead	0.10	0.10
		1,3-Butadiene	0.01	0.01
		Acetaldehyde	0.08	0.40
		Acrolein	0.02	0.06
		Ammonia	24.60	107.70***
		Arsenic	0.01	0.01
		Benzene	0.03	0.10
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Chromium	0.01	0.01
		Cobalt	0.01	0.01
		Dichlorobenzene	0.01	0.01
		Ethyl benzene	0.07	0.30
		Formaldehyde	1.40	6.10
		Hexane	0.60	2.60
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene	0.01	0.02
		Nickel	0.01	0.01
		PAH	0.01	0.02
		Propylene oxide	0.06	0.25
		Selenium	0.01	0.01
Toluene	0.30	1.10		
Xylene	0.20	0.60		

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Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-02	West Side Combustion Turbine/HRSG Stack (No. 2 Fuel Oil)	PM	48.9	45.2
		PM <sub>10</sub>	48.9	45.2
		SO <sub>2</sub>	3.4	3.2
		VOC	11.6	10.7
		CO	53.1	49.1
		NO <sub>x</sub>	52.3	48.4
		Lead	0.10	0.10
		1,3-Butadiene	0.04	0.04
		Ammonia	24.60	107.7***
		Arsenic	0.03	0.03
		Benzene	0.12	0.11
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Chromium	0.03	0.03
		Cobalt	0.01	0.01
		Dichlorobenzene	0.01	0.01
		Formaldehyde	0.62	0.57
		Hexane	0.57	0.53
		Manganese	1.67	1.54
		Mercury	0.01	0.01
Naphthalene	0.07	0.07		
Nickel	0.01	0.01		
PAH	0.08	0.08		
Selenium	0.05	0.05		
Toluene	0.01	0.01		

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EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-03	Auxiliary Boiler	PM	0.7	2.8
		PM <sub>10</sub>	0.7	2.8
		SO <sub>2</sub>	0.1	0.3
		VOC	0.5	2.0
		CO	6.9	30.0
		NO <sub>x</sub>	4.1	17.9
		Lead	0.01	0.01
		Arsenic	0.01	0.01
		Benzene	0.01	0.01
		Beryllium	0.01	0.01
		Cadmium	0.01	0.01
		Chromium	0.01	0.01
		Cobalt	0.01	0.01
		Dichlorobenzene	0.01	0.01
		Formaldehyde	0.01	0.03
		Hexane	0.20	0.70
		Manganese	0.01	0.01
		Mercury	0.01	0.01
		Naphthalene	0.01	0.01
		Nickel	0.01	0.01
Phenanthrene	0.01	0.01		
POM	0.01	0.01		
Selenium	0.01	0.01		
Toluene	0.01	0.01		
SN-04 through SN-15	12-Cell Cooling Tower	PM	3.9	16.9
		PM <sub>10</sub>	0.6	2.3
SN-16 through SN-22 and SN-24 through SN-27	Inlet Cooling System	PM	0.2	0.9
		PM <sub>10</sub>	0.1	0.6
SN-32	Fuel Gas Water Bath Heater (10 MMBtu/hr)	PM	0.1	0.4
		PM <sub>10</sub>	0.1	0.4
		SO <sub>2</sub>	0.1	0.1
		VOC	0.1	0.3
		CO	0.5	2.1
		NO <sub>x</sub>	1.4	6.0

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EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
SN-33	Fuel Gas Water Bath Heater (10 MMBtu/hr)	PM	0.1	0.4
		PM <sub>10</sub>	0.1	0.4
		SO <sub>2</sub>	0.1	0.1
		VOC	0.1	0.3
		CO	0.5	2.1
		NO <sub>x</sub>	1.4	6.0
SN-34	500 Kilowatt Emergency Generator	PM	1.5	0.2
		PM <sub>10</sub>	1.5	0.2
		SO <sub>2</sub>	1.4	0.2
		VOC	1.7	0.3
		CO	4.5	0.6
		NO <sub>x</sub>	20.7	2.6
		Lead	0.10	0.10
		1,3-Butadiene	0.01	0.01
		Acetaldehyde	0.01	0.01
		Acrolein	0.01	0.01
		Benzene	0.01	0.01
		Formaldehyde	0.01	0.01
		Naphthalene	0.01	0.01
		PAH	0.01	0.01
Toluene	0.01	0.01		
Xylene	0.01	0.01		
SN-35	No. 2 Fuel Oil Storage Tank	VOC	40.9	1.1
SN-36	No. 2 Fuel Oil Storage Tank	VOC	40.9	1.1

\*HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.

\*\*Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.

\*\*\* Limit for both natural gas and fuel oil combustion.

### SECTION III: PERMIT HISTORY

Permit #1903-AOP-R0 was issued on August 8, 2000, this was the initial Title V permit for GenPower - Dell. The permit introduced the installation of two GE turbines totaling 640 megawatts. GenPower underwent PSD review for the initial permit which is outlined below. As a part of the PSD review for GenPower, a Best Available Control Technology (BACT) analysis was required. The BACT analysis for GenPower considers emission controls for PM, PM<sub>10</sub>, VOC, CO, and NO<sub>x</sub> (SO<sub>2</sub> emissions were only 35.2 tpy).

#### BACT Summary

Source	Pollutant	BACT Determination		
Combustion Turbines with Duct Burners (SN-01 and SN-02)	PM/PM <sub>10</sub>	Clean fuel/Good combustion practices	0.021 lb/MMBtu	Natural Gas
	SO <sub>2</sub>	Combustion of low sulfur fuels	0.002 lb/MMBtu	Natural Gas
	CO	Good combustion practices and design	0.032 lb/MMBtu	Natural Gas
	VOC	Good combustion practices and design	0.0049 lb/MMBtu	Natural Gas
	NO <sub>x</sub>	SCR and DLN combustion	(3.5 ppm at 0.015 lb/MMBtu)	Natural Gas
Auxiliary Boiler (SN-03)	PM/PM <sub>10</sub>	Clean fuel/Good combustion practices	0.010 lb/MMBtu	Natural Gas
	SO <sub>2</sub>	Combustion of low sulfur fuels	0.001 lb/MMBtu	Natural Gas
	CO	Good combustion practices and design	0.08 lb/MMBtu	Natural Gas
	VOC	Good combustion practices and design	0.005 lb/MMBtu	Natural Gas
	NO <sub>x</sub>	Low NO <sub>x</sub> Burner	0.04 lb/MMBtu	Natural Gas
Cooling Tower (SN-04 through SN-15)	PM/PM <sub>10</sub>	Drift Eliminators and Good Operating Practices	0.003% Drift from the water flow	-
Emergency Generator (SN-23)	PM/PM <sub>10</sub> SO <sub>2</sub> CO VOC NO <sub>x</sub>	0.5% Sulfur Fuel and 250 hours/year usage	-	Diesel Fuel
Fire Pump Engine (Insignif.)	PM/PM <sub>10</sub> SO <sub>2</sub> CO VOC NO <sub>x</sub>	0.5% Sulfur Fuel and 250 hours/year usage	-	Diesel Fuel

Permit #1903-AOP-R1 was issued on September 17, 2001. This modification was made to include ammonia emissions from the SCR. It also changed the name of the facility from Genpower - Dell, LLC to TPS - Dell, LLC.

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Permit #1903-AOP-R2 was issued on May 1, 2002. This modification updated the calculations used to determine the emission rates from the cooling towers and added an inlet cooling system (SN-16 through SN-27) consisting of three four-cell mechanical draft cooling towers and a four cell wastewater cooling tower (SN-28 through SN-31). A suspension of construction extension was issued on December 20, 2004 that lasts until August 7, 2005.

Permit #1903-AOP-R3 was issued on August 15, 2005. This was the initial Title V permit renewal. The facility has a suspension of construction extension that expires on February 7, 2007. This permit modified the permitted HAP emissions based upon more representative emission factors and corrected the emissions from the wastewater cooling tower (SN-28 through SN-31). The changes resulted in increases of permitted emissions of PM by 3.3 tons per year (tpy) and HAPs by 9.21 tpy.

Permit #1903-AOP-R4 was issued on July 18, 2006. With this modification, the facility changed its name from TPS, Dell LLC to Associated Electric Cooperative, Inc. – Dell Power Plant. This modification also increased the permitted hours of operation of SN-03 from 1000 hours per year to 8760 hours per year. Permitted emissions increases from this change were 2.5 tpy PM/PM<sub>10</sub>, 0.2 tpy SO<sub>2</sub>, 1.8 tpy VOC, 27.0 tpy CO and 16.1 tpy NO<sub>x</sub>.

The determination of BACT for SN-03 is based on it being a natural gas fired source. Controls were determined to be good combustion practices, low sulfur fuels, and low NO<sub>x</sub> burners. Increasing the hours of operation did not affect the BACT limits as they are given as a lb/MMBtu emission rate. Also, the modeling/increment analysis were unaffected as they are based on hourly emission rates which were unchanged by this modification.

Permit No. 1903-AOP-R5 was issued on April 30, 2007. The modification added two fuel heaters to the permit as SN-32 and SN-33. Permitted emissions increased by 0.72 tpy PM/PM<sub>10</sub>, 0.06 tpy SO<sub>2</sub>, 0.52 tpy VOC, 4.02 tpy CO and 11.82 tpy NO<sub>x</sub>.

Permit No. 1903-AOP-R6 was issued on May 19, 2008. The modification incorporated the applicable requirements of 40 CFR Part 96 Subparts AAAA-HHHH of the Clean Air Interstate Rule (CAIR) NO<sub>x</sub> Ozone Season Trading Program. No new equipment or changes were proposed.

## SECTION IV: SPECIFIC CONDITIONS

### SN-01 and SN-02

#### Combustion Turbine Generators/Heat Recovery Steam Generators (HRSG) with Duct Burners

##### Source Description

The main emission sources of the facility are the two combustion turbine generators. These generators were supplied by General Electric, and are the GE Frame 7FA models, which operate in their combined cycle mode. These combustion turbines are limited to using natural gas as the primary fuel and No. 2 fuel oil for up to 1,850 hours per year. The GE Frame 7FA model combustion turbines incorporate lean pre-mix dry low NO<sub>x</sub> combustors as well as the add-on Selective Catalytic Reduction (SCR) to minimize NO<sub>x</sub> formation.

The turbine exhaust gas duct through a natural gas fired heat recovery steam generator (HRSG) where steam is produced and used by a steam turbine to generate additional electricity. Each HRSG is specifically designed to match the operating characteristics of the GE combustion turbines to provide optimum performance for the total power cycle. Each HRSG is a three-pressure, reheat, duct fired, natural circulation unit with a horizontal gas turbine exhaust flow receiver containing vertical heat tube transfer sections. Both HRSGs utilize duct firing at 100% load. Duct firing generates additional heat to the exhaust gases of the combustion turbines by burning natural gas. This heat energy is then converted to steam and electricity.

The primary consumer of the steam is a reheat, condensing steam turbine. It consists of a high-pressure section, which receives high-pressure superheated steam from the HRSGs and exhausts to the reheat section of the HRSG. The steam from the reheat section is then supplied to the intermediate-pressure section of the turbine, which expands to the low-pressure section. The low-pressure section of the steam turbine also receives excess low-pressure superheated steam from the HRSGs and exhausts to the condenser unit.

Emissions from the combustion gas turbine generator and the duct fired HRSG system will be exhausted through two stacks 165 feet above the ground surface. The combustion gas turbine generators shut down as necessary for scheduled maintenance, or as dictated by economic or electrical demand.

##### Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by meeting the requirements set forth in Specific Conditions #3 through #18. Hourly emission rates are based on a worst-case fuel use scenario. [Regulation No. 19 §19.501 *et seq.*, Regulation No. 19 §19.901 *et seq.* and 40 CFR Part 52, Subpart E]

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Source	Pollutant	lb/hr	tpy
SN-01 Natural Gas	PM <sub>10</sub>	23.0	100.7
	SO <sub>2</sub>	4.0	17.5
	VOC	6.4	28.0
	CO	56.0	245.3
	NO <sub>x</sub>	30.0	131.4
	Lead	0.10	0.10
	SN-01 No. 2 Fuel Oil	PM <sub>10</sub>	48.9
SO <sub>2</sub>		3.4	3.2
VOC		11.6	10.7
CO		53.1	49.1
NO <sub>x</sub>		52.3	48.4
Lead		0.10	0.10
SN-02 Natural Gas		PM <sub>10</sub>	23.0
	SO <sub>2</sub>	4.0	17.5
	VOC	6.4	28.0
	CO	56.0	245.3
	NO <sub>x</sub>	30.0	131.4
	Lead	0.10	0.10
	SN-02 No. 2 Fuel Oil	PM <sub>10</sub>	48.9
SO <sub>2</sub>		3.4	3.2
VOC		11.6	10.7
CO		53.1	49.1
NO <sub>x</sub>		52.3	48.4
Lead		0.10	0.10

- The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by meeting the requirements set forth in Specific Conditions #3 through #18. Hourly emission rates are based on a worse-case fuel use scenario. [Regulation No. 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

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Source	Pollutant	lb/hr	tpy
SN-01 Natural Gas	PM	32.0	140.2
	1,3-Butadiene	0.01	0.01
	Acetaldehyde	0.08	0.40
	Acrolein	0.02	0.06
	Ammonia	24.60	107.70
	Arsenic	0.01	0.01
	Benzene	0.03	0.10
	Beryllium	0.01	0.01
	Cadmium	0.01	0.01
	Chromium	0.01	0.01
	Cobalt	0.01	0.01
	Dichlorobenzene	0.01	0.01
	Ethyl benzene	0.07	0.30
	Formaldehyde	1.40	6.10
	Hexane	0.60	2.60
	Manganese	0.01	0.01
	Mercury	0.01	0.01
	Naphthalene	0.01	0.02
	Nickel	0.01	0.01
	PAH	0.01	0.02
Propylene oxide	0.06	0.25	
Selenium	0.01	0.01	
Toluene	0.30	1.10	
Xylene	0.20	0.60	
SN-01 No. 2 Fuel Oil	PM	48.9	45.2
	1,3-Butadiene	0.04	0.04
	Ammonia	24.60	107.70
	Arsenic	0.03	0.03
	Benzene	0.12	0.11
	Beryllium	0.01	0.01
	Cadmium	0.01	0.01
	Chromium	0.03	0.03
	Cobalt	0.01	0.01
	Dichlorobenzene	0.01	0.01
	Formaldehyde	0.62	0.57
	Hexane	0.57	0.53
	Manganese	1.67	1.54
	Mercury	0.01	0.01
	Naphthalene	0.07	0.07
	Nickel	0.01	0.01
	PAH	0.08	0.08
Selenium	0.05	0.05	
Toluene	0.01	0.01	

Source	Pollutant	lb/hr	tpy
SN-02 Natural Gas	PM	32.0	140.2
	1,3-Butadiene	0.01	0.01
	Acetaldehyde	0.08	0.40
	Acrolein	0.02	0.06
	Ammonia	24.60	107.70
	Arsenic	0.01	0.01
	Benzene	0.03	0.10
	Beryllium	0.01	0.01
	Cadmium	0.01	0.01
	Chromium	0.01	0.01
	Cobalt	0.01	0.01
	Dichlorobenzene	0.01	0.01
	Ethyl benzene	0.07	0.30
	Formaldehyde	1.40	6.10
	Hexane	0.60	2.60
	Manganese	0.01	0.01
	Mercury	0.01	0.01
	Naphthalene	0.01	0.02
	Nickel	0.01	0.01
	PAH	0.01	0.02
Propylene oxide	0.06	0.25	
Selenium	0.01	0.01	
Toluene	0.30	1.10	
Xylene	0.20	0.60	
SN-02 No. 2 Fuel Oil	PM	48.9	45.2
	1,3-Butadiene	0.04	0.04
	Ammonia	24.6	107.7
	Arsenic	0.03	0.03
	Benzene	0.12	0.11
	Beryllium	0.01	0.01
	Cadmium	0.01	0.01
	Chromium	0.03	0.03
	Cobalt	0.01	0.01
	Dichlorobenzene	0.01	0.01
	Formaldehyde	0.62	0.57
	Hexane	0.57	0.53
	Manganese	1.67	1.54
	Mercury	0.01	0.01
	Naphthalene	0.07	0.07
	Nickel	0.01	0.01
	PAH	0.08	0.08
Selenium	0.05	0.05	
Toluene	0.01	0.01	

3. The permittee shall comply with the following BACT determinations for the two combustion turbine/heat recovery system generators. Compliance with the emission limits set forth in the following table shall be demonstrated by the initial performance test of each of the two stacks at the generators for each fuel type and every five years thereafter. [Regulation No. 19 §19.901 *et seq.* and 40 CFR Part 52, Subpart E]

Sources	Pollutant	BACT Determination		
Turbines In Natural Gas Service				
Each 7FA Combustion Turbine / HRSG with Duct Burners (SN-01 and SN-02)	PM <sub>10</sub>	Use of clean fuels and good combustion practice	0.021 lb/MMBtu	Stack Testing
	SO <sub>2</sub>	Use of low-sulfur fuel and good combustion practice	0.002 lb/MMBtu	Fuel Monitoring
	VOC	Use of clean fuels and good combustion practice	0.0049 lb/MMBtu	Stack Testing
	CO	Use of clean fuels and good combustion practice	0.032 lb/MMBtu	24-hour average (CEMS)
Each Combustion Turbine (with and without Duct Burner firing)	NO <sub>x</sub>	Dry Low NO <sub>x</sub> Combustors with SCR	3.5 ppmvd at 15% O <sub>2</sub>	3-hour average (CEMS)
Turbines In No. 2 Fuel Oil Service <sup>(a)</sup>				
Each 7FA Combustion Turbine / HRSG with and without Duct Burners (SN-01 and SN-02)	PM <sub>10</sub>	Use of clean fuel <sup>(b)</sup> and good combustion practice <sup>(c)</sup>	0.009 lb/MMBtu	Stack Testing (3-hour average) and Fuel Monitoring
	NO <sub>x</sub>	Dry Low NO <sub>x</sub> Burners Water Injection SCR	6 ppmvd @ 15% O <sub>2</sub>	3-hour average (CEMS)
	Visible Emissions	Use of clean fuel and good combustion practice	10%	Method 9 Observations

a. BACT Determination is valid only up to 1,850 hours per year per turbine for fuel oil.

b. Clean fuel is No. 2 fuel oil which contains 0.0015 percent by weight or less of sulfur.

c. "Good combustion practices" are taken to mean (1) the turbines shall be operated in a manner to achieve maximum thermal efficiency via operating only at high loads (e.g., greater than 60 percent of the power output capacity) to the extent possible, (2) the best available combustion fuel oil system for the existing turbines shall be installed and tuned properly to ensure complete (as possible) combustion.

4. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this opacity limit shall be demonstrated by the use of natural gas as a fuel and compliance with Specific Condition #5 during combustion of fuel oil.

Source	Opacity Limit	Regulatory Citation
SN-01 and SN-02 (Natural Gas)	5%	Regulation 18 §18.501
SN-01 and SN-02 (No. 2 Fuel Oil)	10%	Regulation 19 §19.901

5. The permittee will conduct daily observations while burning fuel oil by a person trained in EPA Reference Method 9 and keep a record of these observations. If the permittee detects visible emissions in excess of the permitted limit, the permittee must immediately take action to identify and correct the cause of the excess visible emissions. After implementing the corrective action, the permittee must document the source complies with the visible emissions requirements. The permittee shall maintain records of the

cause of any visible emissions and the corrective action taken. The permittee must keep the records onsite and make the records available to Department personnel upon request. Each opacity record shall be submitted in accordance with General Condition 7. [Regulation No. 19 §19.705 and 40 CFR Part 52, Subpart E]

6. The combustion turbine units may only fire pipeline natural gas or No. 2 fuel oil which contains 0.0015 percent by weight or less of sulfur. [Regulation No. 18 §18.1004, Regulation No. 19 §19.705 and §19.901 *et seq.*, 40 CFR Part 52, Subpart E, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]
7. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #6. For natural gas, these records shall be a copy of the page or pages that contain the gas quality characteristics specified in either a purchase contract or pipeline transportation contract. For fuel oil, all receipts must be accompanied by supplier certifications stating that the concentration of sulfur is 0.0015 percent by weight or less. The records shall be kept on site, and shall be submitted in accordance with General Condition 7. [Regulation No. 19 §19.705 and 40 CFR Part 52, Subpart E]
8. Natural gas firing for the combustion turbine units shall be limited to a total of 39,500 million standard cubic feet per twelve consecutive months. The turbines may combust fuel oil for up to 1,850 hours per twelve consecutive months, each unit. [Regulation No. 18 §18.1004, Regulation No. 19 §19.705 and §19.901 *et seq.*, 40 CFR Part 52, Subpart E, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]
9. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #8. Records shall be updated by the fifteenth day of the month following the month to which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Condition 7. [Regulation No. 19 §19.705 and 40 CFR Part 52, Subpart E]

#### Testing and Monitoring Requirements

10. The permittee shall perform an initial stack test for each fuel type on each Combustion Turbine/HRSG with Duct Burner stack for PM and PM<sub>10</sub> to demonstrate compliance with the limits specified in Specific Conditions #1, #2, and #3. Testing shall be performed initially and every five years thereafter in accordance with Plant Wide Condition #3. Testing shall be performed at 90% or above of the maximum operating load.
  - a. The PM test shall be performed using EPA Reference Methods 5 as found in 40 CFR Part 60, Appendix A.
  - b. The PM<sub>10</sub> test shall be performed by using either EPA Reference Method 201A or 5 as found in 40 CFR Part 60, Appendix A. By using Method 5, the facility will assume that all collected particulate is PM<sub>10</sub>.

[Regulation No. 19 §19.702 and §19.901 *et seq.* and 40 CFR Part 52, Subpart E]

11. Monitoring requirements relative to SO<sub>2</sub> emissions from the Combustion Turbine/HRSG shall be as follows: [Regulation No. 19 §19.703, 40 CFR Part 52, Subpart E, 40 CFR Part 60, Subpart KKKK, 40 CFR Part 75, Subpart B, and A.C.A. §8- 4-203 as referenced by §8-4-304 and §8-4-311]
  - a. The permittee shall monitor the fuel sulfur content daily (unless an alternative monitoring plan is approved by the U.S. EPA).
  - b. The permittee shall conduct SO<sub>2</sub> emission monitoring procedures in accordance with Appendix D of 40 CFR Part 75. For natural gas, these procedures shall include: measuring pipeline natural gas fuel flow rate using an in-line fuel flow meter, determining the gross calorific value of the pipeline natural gas at least once per month, and using the default the emission rate of 0.0006 pounds of SO<sub>2</sub> per million Btu of heat input. For fuel oil, these procedures shall include flow proportional sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank.
  - c. The permittee shall maintain records which demonstrate compliance with Specific Conditions #11(a) and (b).
12. The permittee shall perform a stack test on each Combustion Turbine/HRSG with Duct Burner stack for VOC for each fuel type to demonstrate compliance with the limits specified in Specific Conditions #1 and #3. Testing shall be performed initially and every five years thereafter in accordance with Plant Wide Condition #3 and EPA Reference Method 25A as found in 40 CFR Part 60, Appendix A. Testing shall be performed at 90% or above of the maximum operating load. [Regulation No. 19 §19.702 and §19.901 *et seq.* and 40 CFR Part 52, Subpart E]
13. The permittee shall perform a stack test on each Combustion Turbine/HRSG with Duct Burner stack for CO for each fuel type to demonstrate compliance with the limits specified in Specific Conditions #1 and #3. Testing shall be performed initially and every five years thereafter in accordance with Plant Wide Condition #3 and EPA Reference Method 10 as found in 40 CFR Part 60, Appendix A. Testing shall be performed at 90% or above of the maximum operating load. [Regulation No. 19 §19.702 and §19.901 *et seq.* and 40 CFR Part 52, Subpart E]
14. The permittee shall install, calibrate, maintain, and operate a CO CEMS on each Combustion Turbine/Duct Burner stack. The measured concentration of CO and O<sub>2</sub> in the flue gas along with the measured fuel flow shall be used to calculate CO mass emissions. The CEMS shall be used to demonstrate compliance with the CO mass emission limits specified in Specific Condition #3. CO CEMS shall comply with the

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ADEQ CEMS Conditions, see Appendix G. [Regulation No. 19 §19.703 and §19.901 *et seq.*, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

15. The permittee shall perform a stack test on each Combustion Turbine/HRSG with Duct Burner stack for NO<sub>x</sub> for each fuel type to demonstrate compliance with the limits specified in Specific Conditions #1 and #3. Testing shall be performed initially and every five years thereafter in accordance with Plant Wide Condition #3 and EPA Reference Method 7E as found in 40 CFR Part 60, Appendix A. Testing shall be performed at 90% or above of the maximum operating load. [Regulation No. 19 §19.702 and §19.901 *et seq.* and 40 CFR Part 52, Subpart E]
16. Monitoring requirements relative to NO<sub>x</sub> emissions from the Combustion Turbine/HRSG shall be as follows: [Regulation 19 §19.703, 40 CFR Part 52, Subpart E, 40 CFR Part 60, Subpart KKKK, 40 CFR Part 75, Subpart B, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
  - a. The permittee shall install, calibrate, maintain, and operate a NO<sub>x</sub> CEMS on each Combustion Turbine/HRSG with Duct Burner stack. The CEMS shall comply with 40 CFR Part 75 and with ADEQ CEMS Conditions, see Appendix F. The permittee shall use the measured concentrations of NO<sub>x</sub> and O<sub>2</sub> in the flue gas along with the measured fuel flow (or another 40 CFR Part 75 procedure) to calculate NO<sub>x</sub> mass emissions. The CEMS shall be used to demonstrate compliance with the NO<sub>x</sub> mass emission limits in Specific Condition #3.
  - b. The permittee shall monitor fuel nitrogen content (The permittee shall use the fuel monitoring protocol contained in Appendix E for natural gas).
  - c. The permittee shall maintain records which demonstrate compliance with Specific Condition #16(a).
17. The permittee shall perform a stack test for each fuel type on one of the Combustion Turbine/HRSG with Duct Burner stacks for 1, 3-butadiene, acetaldehyde, acrolein, benzene, ethyl benzene, formaldehyde, naphthalene, PAH, propylene oxide, toluene, xylene, and ammonia, and to quantify other non-criteria pollutants not accounted for in this permit. This test will be used to demonstrate compliance with the limits specified in Specific Condition #2. Testing shall be performed within 180 day of issuance of Permit No. 1903-AOP-R7 in accordance with Plant Wide Condition #3 and EPA Reference Method 18 as found in 40 CFR Part 60, Appendix A. Testing shall be performed at 90% or above of the maximum operating load. [Regulation No. 18 §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]
18. The permittee shall perform a stack test for each fuel type on one of the Combustion Turbine/HRSG with Duct Burner stacks for lead. This test will be used to demonstrate compliance with the limits specified in Specific Condition #2. Testing shall be

performed every five years in accordance with Plant Wide Condition #3 and EPA Reference Method 12 as found in 40 CFR Part 60, Appendix A. Testing shall be performed at 90% or above of the maximum operating load. [Regulation No. 18 §18.1002 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

NSPS Requirements

19. Due to the date of modification, the combustion turbines, heat recovery steam generators, and duct burners (SN-01 and SN-02) are affected sources under 40 CFR Part 60, Subpart KKKK - *Standards of Performance for Stationary Combustion Turbines*. The applicable requirements include but are not limited to the following:

- a. The permittee shall not discharge to the atmosphere any gases from SN-01 or SN-02 that contain the following pollutants in excess of the specified limits. Compliance with Specific Conditions #3 and #7 may be used to demonstrate compliance with these limits.

Pollutant	Emission Limit
SO <sub>2</sub>	0.06 lb/MMBtu
NO <sub>x</sub> (natural gas)	15 ppm @ 15% O <sub>2</sub>
NO <sub>x</sub> (fuel oil)	42 ppm @ 15% O <sub>2</sub>

- b. The permittee shall be exempted from monitoring sulfur content of the fuel under Subpart KKKK provided the permittee retains a current, valid purchase contract, tariff sheet, or transportation contract for the fuel, specifying that the maximum total sulfur content for the fuel is 0.05 weight percent or less for fuel oil or 20 grains per 100 standard cubic feet or less for natural gas. Otherwise, the permittee shall monitor the total sulfur content in accordance with 40 CFR §60.4360. [Regulation No. 19 §19.304 and 40 CFR §60.4365]

- c. Excess emissions for NO<sub>x</sub> is defined as any unit operating period in which the 4-hour or 30-day rolling average NO<sub>x</sub> emission rate exceeds the emission limit in Specific Condition #19(a). The “4-hour rolling average NO<sub>x</sub> emission rate” is the arithmetic average of the average NO<sub>x</sub> emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO<sub>x</sub> emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO<sub>x</sub> emission rate is obtained for at least 3 of the 4 hours. The “30-day rolling average NO<sub>x</sub> emission rate” is the arithmetic average of all hourly NO<sub>x</sub> emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO<sub>x</sub> emissions rates for the preceding 30 unit operating days if a valid NO<sub>x</sub> emission rate is obtained for at least 75 percent of all operating hours. [Regulation No. 19 §19.304 and 40 CFR §60.4380(b)(1)]

- d. Excess emissions for SO<sub>2</sub> is defined as each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine has the potential to exceed the limits in Specific Condition #19(a) and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit. [Regulation No. 19 §19.304 and 40 CFR §60.4385]
  - e. The permittee shall conduct an initial compliance test for NO<sub>x</sub> and SO<sub>2</sub> within 180 days after start-up for each fuel type. The testing shall be conducted for each fuel, at four points in the normal operating range of the turbine. [Regulation No. 19 §19.304, 40 CFR §60.8, and 40 CFR §60.4400 and §60.4415]
20. The following notifications to the Department are required for SN-01 and SN-02: (a) date of construction commenced postmarked no later than 30 days after such date, (b) anticipated date of initial startup between 30-60 days prior to such date, (c) actual date of initial startup postmarked within 15 days after such date, and (d) CEMS, opacity, and emissions performance testing 30 days prior to testing. [Regulation No. 19 §19.304 and 40 CFR §60.7(a)]

#### NESHAP Conditions

21. The permittee shall comply with the notification requirements of 40 CFR §63.6145 which include but are not limited to the following but need not comply with any other requirement of 40 CFR Part 63, Subpart YYYY until EPA takes final action to require compliance and publishes a document in the Federal Register: [Regulation No. 19 §19.304 and 40 CFR §63.6095]
- a. The owner or operator must submit all of the notifications in §63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to the facility by the dates specified.
  - b. The owner or operator must submit an initial notification not later than 120 calendar days after becoming subject to the subpart.

#### Acid Rain Program

22. The Combustion Turbine and HRSG Duct Burner are subject to and shall comply with applicable provisions of the Acid Rain Program (40 CFR Parts 72, 73 and 75). [Regulation No. 19 §19.304]
23. The submission of the NO<sub>x</sub>, SO<sub>2</sub>, and O<sub>2</sub> or CO<sub>2</sub> monitoring plans and notice of CEMS initial certification testing is required at least 45 days prior to the CEMS initial certification testing. [Regulation No. 19 §19.304 and 40 CFR Part 75 - Continuous Emission Monitoring Subpart G]

24. A monitoring plan is required to be submitted for NO<sub>x</sub>, SO<sub>2</sub>, and O<sub>2</sub> or CO<sub>2</sub> monitoring. [Regulation No. 19 §19.304 and 40 CFR Part 75 - Continuous Emission Monitoring Subpart G]
25. The initial NO<sub>x</sub>, SO<sub>2</sub>, and O<sub>2</sub> or CO<sub>2</sub> CEMS certification testing is to occur no later than 90 days after the unit commences commercial operation. [Regulation No. 19 §19.304 and 40 CFR Part 75 Subpart A]
26. The permittee shall ensure that the continuous emissions monitoring systems are in operation and monitoring all unit emissions at all times except during periods of calibration, quality assurance, preventative maintenance or repair, periods of backups of data from the data acquisition and handling system, or recertification. [Regulation No. 19 §19.304 and 40 CFR §75.10]
27. For the purposes of this permit, "upset condition" reports as required by §19.601 of Regulation 19 shall not be required for periods of startup or shutdown of SN-01 and SN-02. The record keeping requirements detailed below shall only apply for emissions which directly result from the start-up and/or shutdown of one or more of the combustion turbine units (SN-01 and SN-02). All other "upset conditions" must be reported as required by Regulation 19. The following conditions must be met during startup and shutdown periods.
  - a. All CEM systems required for SN-01 and SN-02 must be operating during start-up and shutdown. The emissions recorded during these periods shall count toward the annual ton per year emission limits.
  - b. The permittee shall maintain a log or equivalent electronic data record which shall indicate the date, start time, and duration of each start up and shut down event. For natural gas operation, "Startup" shall be defined as the period of time beginning with the first fire within the combustion turbine firing chamber until the units are in "6" mode of operation. "Shutdown" shall be defined as the period of time having initiated the shut down event that the unit(s) drop below "6" mode of operation until fuel is no longer combusted in the firing chamber. Minute data that does not fall in the "6" mode of operation shall not be included in the hourly calculations for NO<sub>x</sub> and CO rolling averages for the purpose of compliance with permit conditions. For fuel oil operation, "Startup" shall be defined as the period of time beginning with the first fire within the combustion turbine firing chamber until the unit(s) reach normal operating mode with water injection and the SCR is operational. "Shutdown" shall be defined as the period of time having initiated the shut down event the unit(s) are outside of normal operating mode and the SCR is not operational until fuel is no longer combusted in the firing chamber. Minute data that does not fall in the "normal SCR operational" mode of operation shall not be included in the hourly calculations for NO<sub>x</sub> and CO rolling averages for the purpose of compliance with the permit conditions. These logs or equivalent

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electronic data records shall be made available to Department personnel upon request.

- c. Opacity is not included. If any occurrences should ever occur, "upset condition" reporting is required.
- d. The facility shall comply with 40 CFR §60.7 reporting and recordkeeping requirements as applicable to NSPS limits and applicable parts of the ADEQ CEMS Conditions.

[Regulation 19, §19.601 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

SN-03

Auxiliary Boiler

Source Description

One natural gas fired, low NO<sub>x</sub> boiler, rated at 83 million BTU/hr, will be located on site to supply steam for startup use at the Dell facility. Steam from this boiler will maintain the operating temperatures of the HRSGs and steam turbine while the combustion turbines are off line. By maintaining operating temperatures the auxiliary boiler will reduce the time necessary to bring the combustion turbines on line. The auxiliary boiler will not be used to augment the power output of the facility during normal operating conditions.

Specific Conditions

28. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by meeting the requirements of Specific Conditions #32 through #35. [Regulation No. 19 §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
SN-03	PM <sub>10</sub>	0.7	2.8
	SO <sub>2</sub>	0.1	0.3
	VOC	0.5	2.0
	CO	6.9	30.0
	NO <sub>x</sub>	4.1	17.9
	Lead	0.01	0.01

29. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition shall be demonstrated through compliance with Specific Condition #33. [Regulation No. 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Source	Pollutant	lb/hr	tpy
SN-03	PM	0.7	2.8
	Arsenic	0.01	0.01
	Benzene	0.01	0.01
	Beryllium	0.01	0.01
	Cadmium	0.01	0.01
	Chromium	0.01	0.01
	Cobalt	0.01	0.01
	Dichlorobenzene	0.01	0.01
	Formaldehyde	0.01	0.03
	Hexane	0.20	0.70
	Manganese	0.01	0.01
	Mercury	0.01	0.01
	Naphthalene	0.01	0.01

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Source	Pollutant	lb/hr	tpy
	Nickel	0.01	0.01
	Phenanthrene	0.01	0.01
	POM	0.01	0.01
	Selenium	0.01	0.01
	Toluene	0.01	0.01

30. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this opacity limit shall be demonstrated by the use of natural gas as a fuel.

Source	Opacity Limit	Regulatory Citation
SN-03	5%	Regulation 18 §18.501

31. The permittee shall comply with all applicable provisions of 40 CFR Part 60, Subpart A - General Provisions and Subpart Dc - *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*. A copy of Subpart Dc is provided in Appendix C. Applicable provisions of Subpart Dc include, but are not limited to the following: [Regulation 19 §19.304 and 40 CFR Part 60, Subpart Dc]
- a. The owner or operator shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup. This notification shall include: [Regulation 19 §19.304 and §60.48c(a)]
    - i. The design heat input capacity of the boiler and identification of fuels to be combusted in the affected facility.
    - ii. The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired.
  - b. Records of the amounts of fuel combusted each month must be kept for SN-03. These records shall be kept on site for two years following the date of such records. [Regulation 19 §19.304 and §60.48c(g) and (i)]
32. The auxiliary boiler may only fire pipeline natural gas. [Regulation No. 18 §18.1004, Regulation No. 19 §19.705 and §19.901 *et seq.*, 40 CFR Part 52 Subpart E, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]
33. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #32. These records shall be a copy of the page or pages that contain the gas quality characteristics specified in either a purchase contract or pipeline transportation contract. These records shall be kept on site and provided to Department personnel upon request. [Regulation 19 §19.705 and 40 CFR Part 52, Subpart E]

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34. The permittee shall comply with the following BACT determinations for the auxiliary boiler. Compliance with the emission limits set forth in the following table shall be demonstrated by meeting the requirements of Specific Condition #33. [Regulation No. 19 §19.901 *et seq.* and 40 CFR Part 52, Subpart E]

Pollutant	BACT Determination	
PM/PM <sub>10</sub>	Clean fuel/Good combustion practices	0.010 lb/MMBtu
CO	Good combustion practices and design	0.08 lb/MMBtu
VOC	Good combustion practices and design	0.005 lb/MMBtu
NO <sub>x</sub>	Low NO <sub>x</sub> Burner	0.04 lb/MMBtu

35. The permittee shall perform an initial stack test on the auxiliary boiler (SN-03) for NO<sub>x</sub> to demonstrate compliance with the limits specified in Specific Condition #34 Testing shall be performed in accordance with Plant Wide Condition #3 and EPA Reference Method 7E as found in 40 CFR Part 60, Appendix A. Testing shall be performed at 90% or above of the maximum operating load. [Regulation 19 §19.702 and §19.901 *et seq.* and 40 CFR Part 52, Subpart E]

## SN-04 Through SN-22 and SN-24 Through SN-27

### Primary, Auxiliary, and Inlet Cooling Systems

#### Source Description

The power plant will employ a closed loop, non-contact cooling water system for the condenser cooling water and other equipment cooling needs. Large quantities of cooling water are required for removal of heat from the steam turbine condensers. Therefore, there are two cooling water systems associated with the Dell facility.

The “primary” cooling system (SN-04 through SN-15) incorporates a twelve cell mechanical draft cooling tower. This consists of a dedicated set of cooling water pumps and associated piping and controls to supply and retrieve water required to absorb excess heat generated by the combined cycle combustion turbines through the surface condenser.

Additional cooling water will be required to support the auxiliary and inlet cooling system (SN-16 through SN-22 and SN-24 through SN-27), which is a closed loop system to cool essential station equipment such as generator hydrogen coolers, turbine lube oil system coolers, and boiler feed pump and motor bearings. This auxiliary system is comprised of a three cell evaporative cooler, a four-cell inlet chiller, a dedicated set of circulating pumps, an expansion tank and piping. Makeup water for the condenser cooling water system, to replace water lost through evaporation and cooling tower drift, will be supplied from deep-well pumps. The water in this system will be treated to retard algae growth in the cooling towers.

Water treatment at the facility will consist of the demineralizer system and the chemical waste neutralization system. The steam generators will require very clean water for the steam generating system. The demineralizer provides high quality demineralized water for use as makeup to the HRSGs. This clean water will be provided from a small treatment plant consisting of demineralizing trains for removal of solids and other impurities; treatment to maintain pH; and treatment to remove dissolved oxygen. TPS Dell will use automatic water analyzers and chemical feed stations to maintain the desired water quality in the condensate and steam systems.

Emissions from the cooling water system include evaporative emissions of particulate matter entrained in the cooling water. This system is not subject to 40 CFR Part 63, Subpart Q for National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers since TPS Dell will use a non-chromate water treatment system.

#### Specific Conditions

36. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by meeting the requirements of Specific Conditions #39 through #42. [Regulation No. 19 §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
SN-04 - SN-15	PM <sub>10</sub>	0.6	2.3
SN-16 - SN-22 and SN-24 - SN-27	PM <sub>10</sub>	0.1	0.6

37. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by meeting the requirements of Specific Conditions #39 through #42. [Regulation No. 18 §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Source	Pollutant	lb/hr	tpy
SN-04 - SN-15	PM	3.9	16.9
SN-16 - SN-22 and SN-24 - SN-27	PM	0.2	0.9

38. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this opacity limit shall be demonstrated by Specific Conditions #41 and #42.

SN	Limit	Regulatory Citation
04 - 22 and 24 -27	20%	Regulation 18 §18.501

39. The total dissolved solids concentration for SN-04 through SN-15 shall not exceed 8,000 parts per million in the water. [Regulation No. 19 §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]
40. The total dissolved solids concentration for SN-16 through SN-22 and SN-24 through SN-27 shall not exceed 1,500 parts per million in the water. [Regulation No. 19 §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6]
41. The permittee shall monitor monthly the total dissolved solids concentration to demonstrate compliance with Specific Condition #39, and weekly to demonstrate compliance with Specific Condition #40. The use of a hand held meter shall be considered as an acceptable compliance method provided that the permittee obtains prior approval from the ADEQ Stack Test Inspector Supervisor for the use of hand held meter and its calibration and maintenance protocol. Otherwise, the permittee shall demonstrate compliance by submitting samples to third party laboratories that use EPA accepted test methods for measuring the conductivity of the sample or TDS concentration. Measured TDS concentration and, if use of a hand held meter is approved, calibration records, shall kept on site and available for inspection. Records shall be updated by the 15<sup>th</sup> day of the month following the month to which the records pertain. Each individual TDS

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concentration shall be submitted in accordance with General Condition 7. [Regulation 19 §19.705 and 40 CFR Part 52, Subpart E]

42. The permittee shall comply with the following BACT determinations for the cooling towers. Compliance with the emission limit set forth in the following table shall be demonstrated by meeting the requirements of Specific Conditions #39 and #40. [Regulation 19 §19.901 *et seq.* and 40 CFR Part 52, Subpart E]

Pollutant	BACT Determination	
PM/PM <sub>10</sub>	Drift Eliminators and Good Operating Practices	0.0005% Drift from the water flow

SN-34

500 Kilowatt Emergency Generator

Source Description

One emergency generator will be installed to provide emergency power for maintaining plant control and critical systems operations during emergencies. The generator, rated at 500kW, will not be operated more than 250 hours per year, and is not intended to provide power for a black start.

Specific Conditions

43. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by meeting the requirements of Specific Conditions #45 through #50. [Regulation No. 19 §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
SN-34	PM <sub>10</sub>	1.5	0.2
	SO <sub>2</sub>	1.4	0.2
	VOC	1.7	0.3
	CO	4.5	0.6
	NO <sub>x</sub>	20.7	2.6
	Lead	0.10	0.10

44. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition will be demonstrated by meeting the requirements of Specific Conditions #45, #46, #49, and #50. [Regulation No. 18 §18.801, effective February 15, 1999, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Source	Pollutant	lb/hr	tpy
SN-34	PM	1.5	0.2
	1,3-Butadiene	0.01	0.01
	Acetaldehyde	0.01	0.01
	Acrolein	0.01	0.01
	Benzene	0.01	0.01
	Formaldehyde	0.01	0.01
	Naphthalene	0.01	0.01
	PAH	0.01	0.01
	Toluene	0.01	0.01
	Xylene	0.01	0.01

45. Visible emissions may not exceed the limits specified in the following table of this permit as measured by EPA Reference Method 9. Compliance with this opacity limit shall be demonstrated by Specific Condition #46.

SN	Limit	Regulatory Citation
34	20%	Regulation 18 §18.501

46. The permittee will conduct daily observations when the generator is operated more than 3 consecutive hours of the opacity from SN-34 by a person trained in EPA Reference Method 9 and keep a record of these observations. If the permittee detects visible emissions in excess of the permitted limit, the permittee must immediately take action to identify and correct the cause of the excess visible emissions. After implementing the corrective action, the permittee must document the source complies with the visible emissions requirements. The permittee shall maintain records of the cause of any visible emissions and the corrective action taken. The permittee must keep the records onsite and make the records available to Department personnel upon request. Each opacity record shall be submitted in accordance with General Condition 7. [Regulation No. 19 §19.705 and 40 CFR Part 52, Subpart E]
47. The emergency generator may only fire diesel fuel containing a maximum of 0.5% sulfur. [Regulation No. 18 §18.1004, Regulation No. 19 §19.705 and §19.901 *et seq.*, 40 CFR Part 52, Subpart E, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]
48. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #47. Records shall be updated by the fifteenth day of the month following the month to which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. Each individual month's data shall be submitted in accordance with General Provision 7. [Regulation 19 §19.705 and 40 CFR Part 52, Subpart E]
49. Operation of the emergency generator shall be limited to 250 hours per twelve consecutive months. [Regulation No. 18 §18.1004, Regulation No. 19 §19.705 and §19.901 *et seq.*, 40 CFR Part 52, Subpart E, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]
50. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #49. Records shall be updated by the fifteenth day of the month following the month to which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision 7. [Regulation 19 §19.705 and 40 CFR Part 52, Subpart E]

SN-32 and SN-33

Fuel Gas Water Bath Heaters

Source Description

These heaters are used to heat the fuel gas prior to combustion. SN-32 has a heat input of 10 MMBtu/hr and SN-33 has a heat input of 12 MMBtu/hr. These units are subject to 40 CFR Part 60, Subpart Dc.

Specific Conditions

51. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by burning only natural gas as a fuel. [Regulation No. 19 §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
SN-32	PM <sub>10</sub>	0.1	0.4
	SO <sub>2</sub>	0.1	0.1
	VOC	0.1	0.3
	CO	0.5	2.1
	NO <sub>x</sub>	1.4	6.0
SN-33	PM <sub>10</sub>	0.1	0.4
	SO <sub>2</sub>	0.1	0.1
	VOC	0.1	0.3
	CO	0.5	2.1
	NO <sub>x</sub>	1.4	6.0

52. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with this condition by burning only natural gas as fuel. [Regulation 18, §18.801 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311]

Source	Pollutant	lb/hr	tpy
SN-32	PM	0.1	0.4
SN-33	PM	0.1	0.4

53. These source are considered affected sources under 40 CFR Part 60, Subpart Dc - *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*. Pursuant to §60.48c (g) and (i), records of the amounts of fuel combusted each month must be kept for SN-32 and SN-33. These records shall be kept on site for two years following the date of such records. [Regulation 19, §19.304 and 40 CFR §60.48c(g) and (i)]

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54. Visible Emissions from these sources shall not exceed 5 percent opacity. Compliance shall be demonstrated by combusting only natural gas as fuel. [Regulation 18, §18.501 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and A.C.A. §8-4-311]

SN-35 and SN-36

No. 2 Fuel Oil Storage Tanks

Source Description

The No. 2 storage tanks are fixed roof tanks, and each tank has a capacity of 1,750,000 gallons.

Specific Conditions

55. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition is through compliance with Specific Condition #57. [Regulation 19, §19.501 *et seq.* and 40 CFR Part 52, Subpart E]

Source	Pollutant	lb/hr	tpy
SN-35	VOC	40.9	1.1
SN-36	VOC	40.9	1.1

56. The permittee shall not exceed the emission rates set forth in the following table. Compliance with this condition is demonstrated based on the maximum annual throughput. [Regulation 19, §19.501 *et seq.* and 40 CFR Part 52, Subpart E]
57. The permittee shall not exceed a combined throughput of 257,380,000 gallons of fuel oil at SN-35 and SN-36 per consecutive twelve month period. [Regulation No. 19 §19.705, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR §70.6]
58. The permittee shall maintain monthly records which demonstrate compliance with Specific Condition #57. Records shall be updated by the fifteenth day of the month following the month to which the records pertain. These records shall be kept on site, and shall be made available to Department personnel upon request. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Provision 7. [Regulation 19 §19.705 and 40 CFR Part 52, Subpart E]

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## **SECTION V: COMPLIANCE PLAN AND SCHEDULE**

AECI - Dell Power Plant will continue to operate in compliance with those identified regulatory provisions. The facility will examine and analyze future regulations that may apply and determine their applicability with any necessary action taken on a timely basis.

## SECTION VI: PLANTWIDE CONDITIONS

1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Regulation 19, §19.704, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [Regulation 19, §19.410(B) and 40 CFR Part 52, Subpart E]
3. The permittee must test any equipment scheduled for testing, unless otherwise stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) new equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) operating equipment according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) days in advance of such test. The permittee shall submit the compliance test results to the Department within thirty (30) days after completing the testing. [Regulation 19, §19.702 and/or Regulation 18 §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
4. The permittee must provide:
  - a. Sampling ports adequate for applicable test methods;
  - b. Safe sampling platforms;
  - c. Safe access to sampling platforms; and
  - d. Utilities for sampling and testing equipment.

[Regulation 19, §19.702 and/or Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee shall maintain the equipment in good condition at all times. [Regulation 19, §19.303 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
6. This permit subsumes and incorporates all previously issued air permits for this facility. [Regulation 26 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

#### Acid Rain (Title IV)

7. The Director prohibits the permittee to cause any emissions exceeding any allowances the source lawfully holds under Title IV of the Act or the regulations promulgated under the Act. No permit revision is required for increases in emissions allowed by allowances acquired pursuant to the acid rain program, if such increases do not require a permit revision under any other applicable requirement. This permit establishes no limit on the number of allowances held by the permittee. However, the source may not use allowances as a defense for noncompliance with any other applicable requirement of this permit or the Act. The permittee will account for any such allowance according to the procedures established in regulations promulgated under Title IV of the Act. A copy of the facility's Acid Rain Permit is attached in an appendix to this Title V permit. [Regulation 26, §26.701 and 40 CFR 70.6(a)(4)]

#### Clean Air Interstate Rule (CAIR) Provisions

8. The permittee will comply with the monitoring, reporting, and recordkeeping requirements of subpart HHHH of 40 CFR part 96. The permittee will comply with the NO<sub>x</sub> emission requirements established under CAIR. The Permittee will report and maintain the records required by subpart HHHH of 40 CFR part 96. A copy of the CAIR permit is attached to this Title V permit. [Regulation No. 19 §19.1401 and 40 CFR Part 52, Subpart E]

#### Title VI Provisions

9. The permittee must comply with the standards for labeling of products using ozone-depleting substances. [40 CFR Part 82, Subpart E]
  - a. All containers containing a class I or class II substance stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced to interstate commerce pursuant to §82.106.
  - b. The placement of the required warning statement must comply with the requirements pursuant to §82.108.
  - c. The form of the label bearing the required warning must comply with the requirements pursuant to §82.110.
  - d. No person may modify, remove, or interfere with the required warning statement except as described in §82.112.
10. The permittee must comply with the standards for recycling and emissions reduction, except as provided for MVACs in Subpart B. [40 CFR Part 82, Subpart F]
  - a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.

- b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.
  - c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.
  - d. Persons disposing of small appliances, MVACs, and MVAC like appliances must comply with record keeping requirements pursuant to §82.166. (“MVAC like appliance” as defined at §82.152)
  - e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to §82.156.
  - f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.
11. If the permittee manufactures, transforms, destroys, imports, or exports a class I or class II substance, the permittee is subject to all requirements as specified in 40 CFR Part 82, Subpart A, Production and Consumption Controls.
12. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.
- The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term “MVAC” as used in Subpart B does not include the air tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC 22 refrigerant.
13. The permittee can switch from any ozone depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR Part 82, Subpart G.

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### SECTION VII: INSIGNIFICANT ACTIVITIES

The following sources are insignificant activities. Any activity that has a state or federal applicable requirement shall be considered a significant activity even if this activity meets the criteria of §26.304 of Regulation 26 or listed in the table below. Insignificant activity determinations rely upon the information submitted by the permittee in an application dated August 20, 2009.

Description	Category
Fire Pump – 1.82 MMBtu/hr	A-1
Diesel Storage Tank – 400 Gallon	A-3
Diesel Storage Tank – 500 Gallon	A-3

## SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq.*) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq.*). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq.*) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 CFR 70.6(b)(2)]
2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 CFR 70.6(a)(2) and §26.701(B) of the Regulations of the Arkansas Operating Air Permit Program (Regulation 26)]
3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Department takes final action on the renewal application. The Department will not necessarily notify the permittee when the permit renewal application is due. [Regulation 26, §26.406]
4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, *et seq.* (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 CFR 70.6(a)(1)(ii) and Regulation 26, §26.701(A)(2)]
5. The permittee must maintain the following records of monitoring information as required by this permit.
  - a. The date, place as defined in this permit, and time of sampling or measurements;
  - b. The date(s) analyses performed;
  - c. The company or entity performing the analyses;
  - d. The analytical techniques or methods used;
  - e. The results of such analyses; and
  - f. The operating conditions existing at the time of sampling or measurement.

[40 CFR 70.6(a)(3)(ii)(A) and Regulation 26, §26.701(C)(2)]

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6. The permittee must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 CFR 70.6(a)(3)(ii)(B) and Regulation 26, §26.701(C)(2)(b)]
7. The permittee must submit reports of all required monitoring every six (6) months. If permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due within thirty (30) days of the end of the reporting period. Although the reports are due every six months, each report shall contain a full year of data. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Regulation No. 26, §26.2 must certify all required reports. The permittee will send the reports to the address below:

Arkansas Department of Environmental Quality  
Air Division  
ATTN: Compliance Inspector Supervisor  
5301 Northshore Drive  
North Little Rock, AR 72118-5317

[40 C.F.R. 70.6(a)(3)(iii)(A) and Regulation 26, §26.701(C)(3)(a)]

8. The permittee shall report to the Department all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.
  - a. For all upset conditions (as defined in Regulation 19, § 19.601), the permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:
    - i. The facility name and location;
    - ii. The process unit or emission source deviating from the permit limit;
    - iii. The permit limit, including the identification of pollutants, from which deviation occurs;
    - iv. The date and time the deviation started;
    - v. The duration of the deviation;
    - vi. The average emissions during the deviation;
    - vii. The probable cause of such deviations;
    - viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future; and
    - ix. The name of the person submitting the report.

The permittee shall make a full report in writing to the Department within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

- b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a.

[Regulation 19, §19.601 and §19.602, Regulation 26, §26.701(C)(3)(b), and 40 CFR 70.6(a)(3)(iii)(B)]

9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 CFR 70.6(a)(5), Regulation 26, §26.701(E), and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. §7401, *et seq.* and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 CFR 70.6(a)(6)(i) and Regulation 26, §26.701(F)(1)]
11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 CFR 70.6(a)(6)(ii) and Regulation 26, §26.701(F)(2)]
12. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR 70.6(a)(6)(iii) and Regulation 26, §26.701(F)(3)]
13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 CFR 70.6(a)(6)(iv) and Regulation 26, §26.701(F)(4)]

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14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Department may require the permittee to furnish such records directly to the Director along with a claim of confidentiality. [40 CFR 70.6(a)(6)(v) and Regulation 26, §26.701(F)(5)]
15. The permittee must pay all permit fees in accordance with the procedures established in Regulation 9. [40 CFR 70.6(a)(7) and Regulation 26, §26.701(G)]
16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 CFR 70.6(a)(8) and Regulation 26, §26.701(H)]
17. If the permit allows different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 CFR 70.6(a)(9)(i) and Regulation 26, §26.701(I)(1)]
18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Department specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 CFR 70.6(b) and Regulation 26, §26.702(A) and (B)]
19. Any document (including reports) required by this permit must contain a certification by a responsible official as defined in Regulation 26, §26.2. [40 CFR 70.6(c)(1) and Regulation 26, §26.703(A)]
20. The permittee must allow an authorized representative of the Department, upon presentation of credentials, to perform the following: [40 CFR 70.6(c)(2) and Regulation 26, §26.703(B)]
  - a. Enter upon the permittee's premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
  - b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;
  - c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and

- d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.
21. The permittee shall submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually within 30 days following the last day of the anniversary month of the initial Title V permit. The permittee must also submit the compliance certification to the Administrator as well as to the Department. All compliance certifications required by this permit must include the following: [40 CFR 70.6(c)(5) and Regulation 26, §26.703(E)(3)]
  - a. The identification of each term or condition of the permit that is the basis of the certification;
  - b. The compliance status;
  - c. Whether compliance was continuous or intermittent;
  - d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit; and
  - e. Such other facts as the Department may require elsewhere in this permit or by §114(a)(3) and §504(b) of the Act.
22. Nothing in this permit will alter or affect the following: [Regulation 26, §26.704(C)]
  - a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
  - b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
  - c. The applicable requirements of the acid rain program, consistent with §408(a) of the Act; or
  - d. The ability of EPA to obtain information from a source pursuant to §114 of the Act.
23. This permit authorizes only those pollutant emitting activities addressed in this permit. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]
24. The permittee may request in writing and at least 15 days in advance of the deadline, an extension to any testing, compliance or other dates in this permit. No such extensions are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion in the following circumstances:
  - a. Such an extension does not violate a federal requirement;
  - b. The permittee demonstrates the need for the extension; and
  - c. The permittee documents that all reasonable measures have been taken to meet the current deadline and documents reasons it cannot be met.

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[Regulation 18, §18.314(A), Regulation 19, §19.416(A), Regulation 26, §26.1013(A), A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

25. The permittee may request in writing and at least 30 days in advance, temporary emissions and/or testing that would otherwise exceed an emission rate, throughput requirement, or other limit in this permit. No such activities are authorized until the permittee receives written Department approval. Any such emissions shall be included in the facility's total emissions and reported as such. The Department may grant such a request, at its discretion under the following conditions:

- a. Such a request does not violate a federal requirement;
- b. Such a request is temporary in nature;
- c. Such a request will not result in a condition of air pollution;
- d. The request contains such information necessary for the Department to evaluate the request, including but not limited to, quantification of such emissions and the date/time such emission will occur;
- e. Such a request will result in increased emissions less than five tons of any individual criteria pollutant, one ton of any single HAP and 2.5 tons of total HAPs; and
- f. The permittee maintains records of the dates and results of such temporary emissions/testing.

[Regulation 18, §18.314(B), Regulation 19, §19.416(B), Regulation 26, §26.1013(B), A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

26. The permittee may request in writing and at least 30 days in advance, an alternative to the specified monitoring in this permit. No such alternatives are authorized until the permittee receives written Department approval. The Department may grant such a request, at its discretion under the following conditions:

- a. The request does not violate a federal requirement;
- b. The request provides an equivalent or greater degree of actual monitoring to the current requirements; and
- c. Any such request, if approved, is incorporated in the next permit modification application by the permittee.

[Regulation 18, §18.314(C), Regulation 19, §19.416(C), Regulation 26, §26.1013(C), A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, and 40 CFR Part 52, Subpart E]

APPENDIX A

40 CFR Part 60, Subpart KKKK – *Standards of Performance for Stationary Gas Turbines*

APPENDIX B

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

APPENDIX C

40 CFR Part 63, Subpart YYYYY – *National Emission Standards for Hazardous Air Pollutants  
for Stationary Combustion Turbines*

Appendix D  
Clean Air Interstate Rule Permit

Appendix E  
Fuel Monitoring Protocol

Appendix F  
Continuous Emissions Monitoring Systems Conditions

Appendix G  
Acid Rain Permit