ADEQ
OPERATING
AIR PERMIT

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

Permit #: 1903-AOP-R2

IS ISSUED TO:

TPS - Dell, LLC
300 East State Highway 18
Dell, AR 72426
Mississippi County
CSN: 47-0448

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:

August 8, 2000 and August 7, 2005

AND IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Keith A. Michaels

Date Modified

SECTION I: FACILITY INFORMATION

PERMITTEE:	TPS - Dell, LLC
CSN:	47-0448
PERMIT NUMBER:	1903-AOP-R2
FACILITY ADDRESS:	300 East State Highway 18 Dell, AR 72426
COUNTY:	Mississippi
CONTACT POSITION:	John T. Duff Vice President - Power Operations
TELEPHONE NUMBER:	813-228-1381
REVIEWING ENGINEER:	Wesley Crouch
UTM North-South (X):	Zone 15 : 3972454
UTM East-West (Y):	Zone 15 : 768463

SECTION II: INTRODUCTION

Summary of Permit Activity

TPS Dell, LLC, is constructing a natural gas fired power plant in Dell, Arkansas. This facility will be a combined cycle electrical generating plant with a nominal rating of 528 MW (with a peak of 640 MW), supplying electrical energy to the Entergy Power Grid via the pre-existing Entergy sub-station located adjacent to the planned site. The permit is being modified to update the calculations used to determine the emission rates from the cooling towers and add 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).

Process Description

This TPS facility will be 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_x) emissions for the facility and meet Arkansas emission guidelines, the facility will be using Selective Catalytic Reduction (SCR) for the combustion turbine-generators.

Regulations

The facility is subject to regulation under the *Arkansas Air Pollution Control Code* (Air Code), the *Regulations of the Arkansas Plan of Implementation for Air Pollution Control* (SIP), and the *Regulations of the Arkansas Operating Air Permit Program* (Title V) because it emits over 100 tons per year of a criteria pollutant. The facility is considered a major stationary source under the Prevention of Significant Deterioration (PSD) regulations as found in 40 CFR 52.21. As described below and throughout the permit, the facility is subject to PSD requirements. Several of the proposed sources at TPS are also subject to the New Source Performance Standards (NSPS). The combustion turbines are subject to 40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines while the duct burners are subject to Subpart Da - Standards of Performance for Electric Utility Steam Generating Units. Additionally, the auxiliary boiler is subject to Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

TPS - Dell, LLC
Permit #: 1903-AOP-R2
CSN #: 47-0448

FACILITY EMISSION SUMMARY

The following table is a summary of emissions from the facility. Specific conditions and emissions for each source can be found starting on the page cross referenced in the table.

EMISSION SUMMARY					
Source No.	Description	Pollutant	Emission Rates		Cross Reference Page
			lb/hr	tpy	
Total Allowable Emissions		PM PM_{10} SO_2 VOC CO NO_x Formaldehyde Ammonia	70.2 48.1 8.7 24.8 127.5 71.8 2.2 49.2	301.4 204.6 35.2 103.8 524.1 265.9 9.6 215.4	
01	North Side Combustion Turbine/HRSG Stack	PM PM_{10} SO_2 VOC CO NO_x Formaldehyde Ammonia	32.0 23.0 4.0 11.8 59.4 30.0 1.0 24.6	140.1 100.7 17.5 51.7 260.2 131.4 4.7 107.7	20
02	South Side Combustion Turbine/HRSG Stack	PM PM_{10} SO_2 VOC CO NO_x Formaldehyde Ammonia	32.0 23.0 4.0 11.8 59.4 30.0 1.0 24.6	140.1 100.7 17.5 51.7 260.2 131.4 4.7 107.7	20

EMISSION SUMMARY					
Source No.	Description	Pollutant	Emission Rates		Cross Reference Page
			lb/hr	tpy	
03	Auxiliary Boiler	PM PM_{10} SO_2 VOC CO NO_x Formaldehyde	0.7 0.7 0.2 0.5 7.0 4.2 0.1	0.3 0.3 0.1 0.3 3.5 2.1 0.1	31
04 - 15	12-Cell Cooling Tower	PM PM_{10}	3.9 0.6	16.9 2.3	34
16 -27	Inlet Cooling System	PM PM_{10}	0.2 0.1	0.6 0.4	34
23	500 Kilowatt Emergency Generator	PM PM_{10} SO_2 VOC CO NO_x Formaldehyde	0.6 0.6 0.5 0.7 1.7 7.6 0.1	0.1 0.1 0.1 0.1 0.2 1.0 0.1	37
28-31	Wastewater Cooling Tower	PM PM_{10}	1.5 0.1	6.6 0.1	

SECTION III: PERMIT HISTORY

1903-AOP-R0 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. A BACT determination is a case-by-case analysis that addresses the technological question of whether a proposed control technique can be considered BACT for the particular application or whether a more stringent level of emission control should be used. This determination involves an assessment of the availability of applicable technologies capable of sufficiently reducing a specific pollutant emission, as well as weighing the economic, energy, and environmental impacts using each technology.

The methodology used by the permittee to determine BACT followed the "top-down" approach. The "top-down" BACT contains the following elements:

1. Determination of the most stringent control alternatives potentially available.
2. Discussion of the technical and economic feasibility of each alternative.
3. Assessment of energy and environmental impacts, including toxic and hazardous pollutant impacts, of feasible alternatives.
4. Selection of the most stringent control alternative that is technically and economically feasible and that provides the best overall control of all pollutants.

The selected BACT must be at least as stringent as New Source Performance Standards for the source.

A BACT analysis was performed for each regulated pollutant emitted in amounts that exceed the PSD significance levels. BACT applies to each emissions unit at which a significant net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit. Therefore, the BACT analysis for GenPower considers emission controls for PM, PM_{10}, VOC, CO, and NO_x (SO_2 emissions are only 35.2 tpy). Note that for particulate matter and VOC emissions, the BACT review process is greatly simplified because the combustion turbines/duct burners for this project will be fired solely with natural gas, which is the cleanest fuel available. Good combustion practices of natural gas results in the lowest achievable emission rate of particulate matter and VOC, and is acceptable as BACT. The following sources were required to undergo a BACT analysis:

- Combustion Turbines with HRSG Duct Burners (SN-01 and SN-02)
- Auxiliary Boiler (SN-03)
- Cooling Towers
- Emergency Generator (SN-23)
- Fire-Water Pump Engine (SN-24)

BACT Analysis for Combustion Turbines

NO_x

The following is a top-down list of control technologies and the achievable emission levels that were considered for NO_x reduction.

Xonon Technology	2 ppm
$SCONO_x$ Technology	2 ppm
Selective Catalytic Reduction (SCR)	3.5 ppm
Selective Non-Catalytic Reduction (SNCR)	5 ppm
Dry Low NO_x Combustors (DLN)	9 ppm
Water/Steam Injection	25 ppm

GenPower has proposed that the BACT for NO_x emissions is Dry Low NO_x Combustors (DLN) combined with Selective Catalytic Reduction (SCR) at 3.5 ppm (GE turbines are delivered equipped with DLN). Xonon Technology has reported successful testing on smaller machines for limited periods of time. This development hasn't presented any evidence of long term success nor has it been proven on a large commercial scale. In terms of $SCONO_x$ Technology, the manufacturer, Goal Line Technologies, has reported successful testing of the $SCONO_x$ technology at smaller combustion turbine facilities, but successful long term testing at large commercial combustion turbine installations has not occurred. Although it has been stated that emission rates of 2 ppm can be achieved with this technology, it is still very expensive. A capital cost worksheet provided by ABB Alstom Power taking into account the purchase and operation of a $SCONO_x$ system resulted in a cost of $20,257 per ton of NO_x removed per turbine. This was not a feasible emission control cost and therefore the next available control technology (SCR) was chosen and accepted by the Department.

CO

The following is a top-down list of control technologies and the achievable emission levels that were considered for CO reduction.

Catalytic Oxidation	5 ppm
Dry Low NO_x Combustors (DLN)	7 ppm
Proper Combustion Practices	7 ppm
Good Equipment Design	7 ppm

GenPower has proposed that the BACT for CO emissions is Dry Low NO_x Combustors at 7 ppm. The use of catalytic oxidation can have large financial penalties (approximately $13,000/ton) for the operator due to the additional pressure drop in the HRSG gas passage requiring additional electrical energy consumption and the additional downtime required to clean the catalyst surfaces resulting in lost generation. Carbon monoxide emissions generated during the combustion process are dependent upon the design of the combustion system. Specifically, the fuel-to-air ratios and staging of combustion air. GE estimates CO emissions from a Model 7FA machine using DLN combustors to be between 7 and 8 ppm. Therefore GenPower's proposal of Dry Low NO_x as BACT is acceptable.

Particulates

The permittee proposed that BACT for the PM/PM_{10} emissions from the combustion turbine as clean fuels and good combustion practices. GenPower has identified baghouses, electrostatic precipitators, scrubbers, and combustion of clean fuels as the most stringent control alternatives potentially available to control PM/PM_{10} in gaseous streams. None of the add-on control technologies were determined to be BACT according to the RBLC. Therefore, clean fuels qualifies as BACT for the PM/PM_{10} emissions from the combustion turbines.

SO_2

BACT analysis is not required for SO_2, but the permittee proposed that emission controls from the combustion turbines is combustion of low sulfur fuels. The only add-on control technology identified was an SO_2 scrubber. Scrubbers are not identified as control on the RBLC and are considered technically infeasible for control on the turbine. The pipeline natural gas to be used at the turbines will contain less than 0.5 grains per 100 cubic feet resulting in very low SO_2 emissions. The permittee's proposal is consistent with the RBLC entries.

VOC

The permittee proposed that BACT for VOC emissions from the combustion turbines is good combustion practices. The only add-on control technology identified was catalytic oxidation. There are very few listings in the RBLC in which this method of control was employed for controlling VOC emissions. There are negative environmental impacts associated with the use of this control technology created by the handling and disposal of the spent catalyst, which is classified as a hazardous waste. Therefore, combustion of clean fuels qualifies as BACT for the VOC emissions from the combustion turbines.

BACT Analysis for HRSG Duct Burners

NO_x

The following is a top-down list of control technologies and the achievable emission levels that were considered for NO_x reduction.

Selective Catalytic Reduction (SCR) w/ DLN	3.5 ppm
Low NO_x Burners (DLN)	12 ppm

GenPower has proposed that the BACT for NO_x emissions is Selective Catalytic Reduction (SCR) at 4.5 ppm while the Duct Burner is firing. Individual BACT standards and emission rates are not included for the duct burners alone, but instead combined with the combustion turbines (duct burners are never used independent of the turbines). The catalyst bed for the SCR is located after the HRSG, therefore SCR is accepted as BACT for the duct burners.

CO

The following is a top-down list of control technologies and the achievable emission levels that were considered for CO reduction.

Catalytic Oxidation	5 ppm
Proper Combustion Practices	13 ppm
Good Equipment Design	13 ppm

GenPower has proposed that the BACT for CO emissions is proper combustion practices and good equipment design with an emission rate of 13 ppm. The use of catalytic oxidation can have large financial penalties for the operator due to the additional pressure drop in the HRSG gas passage requiring additional electrical energy consumption and the additional downtime required to clean the catalyst surfaces resulting in lost generation. Listings within the RBLC indicates that the use of catalytic oxidation to reduce CO on duct burners is very uncommon and typically in non-attainment areas. Therefore, the proposal of proper combustion techniques and good design is accepted as BACT.

Particulates

The permittee proposed that BACT for the PM/PM_{10} emissions from the duct burners as clean fuels and good combustion practices. GenPower has identified baghouses, electrostatic precipitators, scrubbers, and combustion of clean fuels as the most stringent control alternatives potentially available to control PM/PM_{10} in gaseous streams. None of the add-on control technologies were determined to be BACT since the control options were not cost effective. Therefore, clean fuels qualifies as BACT for the PM/PM_{10} emissions from the duct burners.

SO_2

The permittee proposed emission controls for the SO_2 emissions from the duct burners is combustion of low sulfur fuels. A review of the RBLC for SO_2 control determinations found no add-on control devices for natural gas fired duct burners. The pipeline natural gas to be used at the duct burners will contain less than 0.5 grains per 100 cubic feet resulting in very low SO_2 emissions. The permittee's proposal is consistent with the RBLC entries. Therefore, combustion of clean fuels is acceptable for the SO_2 emissions from the duct burners.

VOC

The permittee proposed that BACT for VOC emissions from the duct burners is good combustion practices. The only add-on control technology identified was catalytic oxidation. There are very few listings in the RBLC in which this method of control was employed for controlling VOC emissions. There are negative environmental impacts associated with the use of this control technology created by the handling and disposal of the spent catalyst, which is classified as a hazardous waste. Therefore, combustion of clean fuels qualifies as BACT for the VOC emissions from the duct burners.

BACT Analysis for the Auxiliary Boiler

GenPower proposes to install a natural gas fired boiler, rated at a maximum heat input of 83.0 million BTU per hour. This boiler will supply steam for auxiliary equipment during the startups and shutdowns. Its use is projected to be less than 1,000 hours per year. Due to the low emissions that accompany a limited amount of operation, installing add-on control devices for any of the regulated pollutants other than NO_x is not warranted. A low NO_x burner will be installed because it is a cost effective addition increasing the purchase price by $30,000 (emission limit of 0.04 lb/MMBtu). Since the boiler will be fired with only natural gas, BACT for Particulates, SO_2, CO and VOC is accepted as the use of clean fuel and good combustion practices.

BACT Analysis for the Cooling Tower

Large quantities of cooling water are required for removal of heat from the steam turbine condensers. The proposed facility will employ a closed loop, non-contact cooling water system for the condenser cooling water and other equipment cooling needs. The proposed facility will include a mechanical draft cooling tower equipped with 12 cells. The particulate emissions from the cooling tower are subject to a BACT determination. GenPower has elected to install drift eliminators and to utilized good operating practice for the cooling towers in order to minimize particulate emissions. A search of the RBLC resulted in only a few entries for control of particulate matter. In all cases, drift eliminators and good operating practices were utilized as BACT and therefore are consistent with GenPower's BACT request.

BACT Analysis for the Emergency Generator and Fire Pump

GenPower will install a diesel engine driven emergency generator rated at 500kw and a diesel engine driven emergency fire pump. The generator will be used during emergencies when there is a loss of offsite power while the fire pump will be used for fire fighting purposes. Each is expected to operate less than 250 hours per year. Due to the low amount of operation that is anticipated, there are no add-on control devices that would be feasible for either engine. GenPower has proposed that BACT for both engines be 0.5% sulfur content limit in the diesel fuel and a limit of 250 hours per year. This proposal is acceptable as BACT for the engines.

BACT Summary

The following table is a summary of the BACT determinations for the facility. In the event of any disagreement between this table and subsequent permit conditions, the permit conditions shall take precedence.

Source	Pollutant	BACT Determination		
Combustion Turbines with Duct Burners (SN-01 and SN-02)	PM/PM_{10}	Clean fuel/Good combustion practices	0.021 lb/MMBtu	Natural Gas
	SO_2	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_x	SCR and DLN combustion	(3.5 ppm at 0.015 lb/MMBtu)	Natural Gas

Source	Pollutant	BACT Determination		
Auxiliary Boiler (SN-03)	PM/PM_{10}	Clean fuel/Good combustion practices	0.010 lb/MMBtu	Natural Gas
	SO_2	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_x	Low NO_x Burner	0.04 lb/MMBtu	Natural Gas
Cooling Tower (SN-04 through SN-15)	PM/PM_{10}	Drift Eliminators and Good Operating Practices	0.003% Drift from the water flow	-
Emergency Generator (SN-23)	PM/PM_{10} SO_2 CO VOC NO_x	0.5% Sulfur Fuel and 250 hours/year usage	-	Diesel Fuel
Fire Pump Engine (Insignif.)	PM/PM_{10} SO_2 CO VOC NO_x	0.5% Sulfur Fuel and 250 hours/year usage	-	Diesel Fuel

Ambient Air Analysis

An air dispersion modeling analysis is required as part of a PSD permit application. The air dispersion modeling analysis is used to demonstrate that emissions from the combustion turbine units will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or exceed a PSD Increment. The air quality analysis is organized into two major sections for each applicable pollutant: the significance analysis and the full impact analysis. The full impact analysis is further subdivided into the NAAQS and PSD Increment Analysis.

Worst Case Load Analysis

An analysis was required in order to determine under what circumstances the proposed GenPower facility has the greatest opportunity to adversely effect the ambient air quality in the region. This was accomplished by running the screening model (SCREEN3 version 96043) for the emissions of the combustion turbines with the HRSG duct burners in place at 100%, 75% and 50% load for each pollutant at three different operating temperatures representing winter, summer and average. SCREEN3 was also run to account for emissions from the auxiliary boiler and the cooling tower. Due to the topography of the region around the proposed site, all major emission source model runs were completed on flat terrain. The following table outlines the emission results from both of the combustion turbines.

Turbine Load		100%				75%			50%		
Temperature (ºF)		-13	62.3	108 off	108 on	-13	62.3	108	-13	62.3	108
Pollutant	Averaging Period	Maximum Calculated Concentration (μg/m^3)									
NO_x	Annual	2.08	1.92	**2.10**	1.85	1.71	1.73	1.63	1.65	1.63	1.42
PM_{10}	24-Hour	7.63	7.56	9.27	7.55	7.73	8.20	8.63	9.22	**9.66**	9.63
	Annual	1.53	1.51	1.85	1.51	1.55	1.64	1.73	1.84	**1.93**	**1.93**
PM	24-Hour	3.12	3.09	3.63	3.09	3.66	3.88	4.09	4.37	**4.58**	4.56
	Annual	0.62	0.62	0.73	0.62	0.73	0.78	0.82	0.87	**0.92**	091
SO_2	3-Hour	2.34	**3.09**	2.72	2.32	1.83	1.94	2.04	2.19	2.29	1.14
	24-Hour	1.04	**1.37**	1.21	1.03	0.81	0.86	0.91	0.97	1.02	0.51
	Annual	0.21	**0.27**	0.24	0..21	0.16	0.17	0.18	0.19	0.20	0.10
CO	1-Hour	46.84	46.37	**54.42**	48.02	25.42	24.81	23.84	25.49	24.16	22.80
	8-Hour	32.79	32.46	**38.09**	33.61	17.79	17.37	16.69	17.84	16.91	15.96

Additionally, a screening model was run on the auxiliary boiler and the cooling towers resulting in the following concentrations.

Source		Auxiliary Boiler	Cooling Tower
Pollutant	Averaging Period	Maximum Calculated Concentration (μg/m^3)	
NO_x	Annual	6.10	-
PM_{10}	24-Hour	4.69	8.12
	Annual	0.94	1.62
PM	24-Hour	4.69	15.42
	Annual	0.94	3.08

SO_2	3-Hour	2.64	-
	24-Hour	1.17	-
	Annual	0.23	-
CO	1-Hour	129.10	-
	8-Hour	90.37	-

The screening indicated that the worst-case load conditions for CO and NO_x at the combustion turbine/duct burner sources were at 100% load in the summer with cooling off. Similarly, SO_2 emissions reached maximum theoretical concentration at 100% load at average temperatures. Concentrations for particulates were at their maximum at 50% load at average temperatures. All of the modeling situations were run as natural gas as a fuel source.

Building Downwash

The Clean Air Act limits the use of dispersion techniques, such as stack heights, to meet the NAAQS or PSD Increments. However, building downwash effects must be considered for stacks shorter than the GEP (Good Engineering Practice) stack height. All of the stacks at GenPower's proposed facility calculated out below the GEP stack height, therefore the building downwash procedure was followed considering cavity region effects and then building wake effects. The cavity concentrations for each source were computed using the SCREEN3 model software. All of the maximum cavity concentrations occur within the boundaries of the property, so they will not be included in the modeling analysis.

Significance Analysis

The significance analysis considers the emissions associated with the proposed turbines in order to determine whether or not the proposed facility's emissions will have a significant impact upon the area surrounding the facility. If the results of the significance analysis are above the Modeling Significance Levels, the full impact analysis will be required for that pollutant. In addition, if the results of the significance analysis are above the Monitoring De Minimis Concentration, PSD ambient monitoring requirements must also be addressed for that pollutant. The results of the significance analysis for GenPower were below the Modeling Significance Levels for SO_2 and CO and therefore the full impact analysis was not required for these pollutants. However, maximum concentrations for NO_x (annual) and PM_{10} (24-hour) still exceed the Significant Modeling Concentration levels. As a result, multi-source refined modeling was required for these pollutants and their respective averaging periods in order to determine compliance with the NAAQS and PSD Increments. In all cases, the concentrations that resulted from the refined modeling were below the Monitoring DeMinimis Concentration, therefore ambient monitoring is not required for any pollutant. The results of the air dispersion modeling analysis is contained in the following table.

Pollutant	Averaging Period	Total Facility Concentration (Fg/m^3)	Modeling Significance Level (Fg/m^3)	Refined Modeling (Yes/No)	Monitoring DeMinimis Concentration (Fg/m^3)	Ambient Monitoring (Yes/No)	Maximum Refined Concentration (Fg/m^3)
PM_{10}	24-hour	22.47	5	Yes	10	No*	5.62632
	Annual	4.49	1	Yes	--	--	--
SO_2	3-hour	5.73	25	No	--	--	--
	24-hour	2.54	5	No	13	No	--
	Annual	0.50	1	No	--	--	--
CO	1-hour	183.52	2000	No	--	--	--
	8-hour	128.46	500	No	575	No	--
NO_X	Annual	8.20	1	Yes	14	No	1.10639

* Monitoring concentration was exceeded in initial SCREEN3 modeling, but not in refined modeling

For the multi-source modeling analysis, the modeling domain was extended from 10 kilometers to 50 kilometers from the center of the proposed facility. Receptors were placed every 1000 meters. The ISCST3 model was used to model concentrations of NO_x (annual average) and PM_{10} (24-hour average) in the impact area surrounding the proposed GenPower facility. The NAAQS and PSD Increment compliance modeling was performed using five years of meteorological data and the facility emissions based on worst-case scenarios. The modeled concentrations that were used in determining compliance with the PSD Increment and the NAAQS were the highest annual average for NO_x and the highest, sixth-highest estimates for particulates. Results for both the NAAQS and PSD Increment compliance modeling are discussed below.

NAAQS

Results of the multi-source modeling showed that the net emissions from the proposed GenPower facility do not result in a significant ambient impact for any modeled pollutant at any point in the modeled domain. At no point on the receptor grid were the NAAQS exceeded for NO_x emissions. In terms of particulate matter, within the 50 kilometer receptor grid, there was one receptor that exceed the NAAQS, however this receptor was located within the property boundary of Osceola Products. Additionally, at Osceola, the maximum contribution by the proposed GenPower facility was 0.03 $\mu g/m^3$. This contribution represents 0.02% of the 150 μg/m^3 standard and is therefore not a limiting factor in the construction of the proposed facility. Outside of this property boundary, the NAAQS were not exceeded for PM_{10} emissions. The table below summarizes the NAAQS modeling results.

Pollutant	Averaging Period	NAAQS Standard (μg/m^3)	Background Location and Value	Multi-Source Modeled Concentrations (μg/m^3)				
				1992	1993	1994	1995	1996
PM_{10}	24-Hour	150	West Memphis 44 μg/m^3	102.1	101.8	101.5	101.7	101.9
NO_x	Annual	100	Little Rock 20.7 μg/m^3	39.79	38.80	37.93	42.42	40.48

PSD Increment

Results of the multi-source modeling showed that the net emissions from the proposed GenPower facility do not result in a significant ambient impact for any modeled pollutant at any point in the modeled domain. Within the 50 kilometer receptor grid, there were five receptors that exceed the PSD Increment for particulates, however all five of these receptors were located within the property boundaries of other facilities (Nucor Yamato, Nucor Steel, and Terra Nitrogen) that were included in the multi-source modeling. Outside of property boundaries, the increment was not exceeded for PM_{10} emissions. Additionally, at each of the receptors where PSD Increment was exceeded, the maximum contribution by the proposed GenPower facility was 0.036 μg/m^3. This contribution represents 0.12% of the 30 μg/m^3 standard for PM_{10} and is therefore not a limiting factor in the construction of the proposed facility. In terms of NO_x, there are no receptors that exceed the PSD Increment, thus GenPower poses no threat to exceed the increment. The Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation 19) states in Section 19.904(C)(4) that an air quality impact analysis is required to also verify that no individual major source would result in the consumption of 50% of any available annual increment or 80% of any short term increment. It was found that the annual contribution to the increment for NO_x to be 0.27% and the highest short-term contribution to the increment for PM_{10} to be 0.28%. Each pollutant's contribution is well below the Regulation 19 requirements. The table below summarizes the PSD Increment modeling results.

Pollutant	Averaging Period	PSD Class II Increment ($\mu g/m^3$)	Increment Available ($\mu g/m^3$)	Highest Maximum Contribution to PSD Increment ($\mu g/m^3$)	Maximum Increment Consumed
PM_{10}	24-Hour	30	-	0.084	0.28%
NO_x	Annual	25	7.74	0.021	0.27%

Additional Impacts Analysis

PSD permits are required to assess the impacts of air, ground, and water pollution on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source or modification under review, and from associated growth.

Growth Analysis
The potential for general commercial, residential, industrial and other growth associated with the proposed GenPower facility was evaluated to determine possible air quality effects. Construction of the facility is expected to take 22 months. Thus, the general increase in activity and any resulting air emissions associated with the facility construction will be temporary. It is anticipated that the existing commercial and industrial establishments in the region will support the labor force, without significant expansion of existing facilities or construction of new businesses. In addition, since a portion of the work force will come from the surrounding communities, no additional residential growth is expected.

Although there will likely be a general increase in activity in the surrounding communities as a result of the facility, the operation of the facility is not expected to result in substantial increase in growth. A primary reason is that the facility will not require frequent deliveries or shipment of raw material or other goods. The facility's primary input, natural gas fuel, will be obtained from a pipeline.

Class I Area and Visibility Analysis
The Class I Area nearest to the proposed GenPower facility is the Mingo National Wilderness area in Missouri. It is located approximately 120 kilometers north. As a result, Class I Area analysis for visibility was not performed. Plume visibility analysis was performed for the proposed facility. The analysis was performed using VISCREEN and results indicate that plume delta E and Plume contrast do not exceed screen criterion for Sky or Terrain background.

<u>Soils and Vegetation Analysis</u>

To assess the facility's impacts on soils and vegetation, the effects of deposition and direct exposure were analyzed. Because GenPower will not fire any liquid fuels in the combustion turbines, no assessment of soils impacts were required. In terms of direct exposure to vegetation, the EPA has organized levels at which visible damage or growth retardation may occur, or the observed minimum levels at which injury and mortality to plants have been reported. Air pollutants emitted by the combustion turbines for which sensitivity levels are provided are SO_2, NO_2, and CO. The following table compares SCREEN3 model results from the proposed GenPower facility with sensitivity levels for vegetation. Results indicate that emissions from the facility are not expected to cause damage to vegetation.

Pollutant	Averaging Period	Maximum Modeled Concentration ($\mu g/m^3$)	Sensitivity Level
NO_x	4-Hour	144.8*	3760
	8-Hour	144.8*	3760
	Month	144.8*	564
	Annual	11.66	100
SO_2	1-Hour	6.37*	917
	3-Hour	5.73	786
	Annual	0.51	18
CO	Week	183.5*	1,800,000
*Maximum 1-hour SCREEN3 Results			

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.

SECTION IV: EMISSION UNIT INFORMATION

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 will be supplied by General Electric, and are the GE Frame 7FA models, which will be used in their combined cycle mode. These combustion turbines will be limited to using natural gas as a fuel, which will be obtained from a pipeline approximately 3 miles south of the facility. The GE Frame 7FA model combustion turbines incorporate lean pre-mix dry low NO_x combustors as well as the add-on Selective Catalytic Reduction (SCR) to minimize NO_x formation.

The turbine exhaust gas will duct through a natural gas fired heat recovery steam generator (HRSG) where steam will be 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 will 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 will be shut down as necessary for scheduled maintenance, or as dictated by economic or electrical demand.

Specific Conditions

1. Pursuant to §19.501 et seq, §19.901 of Regulation 19 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E, the permittee shall not exceed the emission rates set forth in the following table. Initial compliance with the emission rates set forth in the following table shall be demonstrated by the initial performance test of the two Turbine / HRSG stacks. Continuing compliance with this condition will be demonstrated by meeting the requirements set forth in Specific Condition #3 through #16. Hourly emission rates are based on a worst-case scenario.

Source	Pollutant	lb/hr	tpy
SN-01	PM_{10}	23.0	100.7
	SO_2	4.0	17.5
	VOC	11.8	51.7
	CO	59.4	260.2
	NO_X	30.0	131.4
SN-02	PM_{10}	23.0	100.7
	SO_2	4.0	17.5
	VOC	11.8	51.7
	CO	59.4	260.2
	NO_X	30.0	131.4

2. Pursuant to §18.801 of the Arkansas Air Pollution Control Code (Regulation #18) effective February 15, 1999, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, the permittee shall not exceed the emission rates set forth in the following table. Initial compliance with the emission rates set forth in the following table shall be demonstrated by the initial performance test of the two Turbine / HRSG stacks. Continuing compliance with this condition will be demonstrated by meeting the requirements set forth in Specific Condition #4 through #16. Hourly emission rates are based on a worse-case scenario.

Source	Pollutant	lb/hr	tpy
SN-01	PM	32.0	140.1
	Ammonia	24.6	107.7
	Formaldehyde	1.0	4.7
SN-02	PM	32.0	140.1
	Ammonia	24.6	107.7
	Formaldehyde	1.0	4.7

3. Pursuant to §19.901 of Regulation 19 et seq, and 40 CFR Part 52, Subpart E, the permittee shall comply with the following BACT determinations for the two combustion turbine / heat recovery system generators. Initial 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.

Sources	Pollutant	BACT Determination		
Each 7FA Combustion Turbine / HRSG with Duct Burner (SN-01 and SN-02)	PM_{10}	Use of clean fuels and good combustion practice	0.021 lb/MMBtu	Stack Testing
	SO_2	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_x	Dry Low NO_x Combustors with SCR	3.5 ppmvd at 15% O_2	3-hour average (CEMS)

Opacity Limitation

4. Pursuant to §18.501 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, the permittee shall not discharge into the atmosphere gases from the two stacks which exhibit an opacity greater than 5%. Compliance with this opacity limit shall be demonstrated by the use of natural gas as a fuel. [Note: NSPS Subpart Da requires an initial test of opacity from the Duct Burner]

Throughput Limitations

5. Pursuant to §18.1004 of Regulation #18, §19.705 and §19.901 et seq of Regulation #19, 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, the combustion turbine units may only fire pipeline natural gas.

6. Pursuant to §19.705 of Regulation 19, and 40 CFR Part 52, Subpart E, the permittee shall maintain monthly records which demonstrate compliance with Specific Condition #5. 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 shall be submitted in accordance with General Condition #7.

7. Pursuant to §18.1004 of Regulation #18, §19.705 and §19.901 et seq of Regulation #19, 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, 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.

8. Pursuant to §19.705 of Regulation 19, and 40 CFR Part 52, Subpart E, the permittee shall maintain monthly records which demonstrate compliance with Specific Condition #7. 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.

Testing and Monitoring Requirements

9. Pursuant to §19.702 and §19.901 of Regulation 19, and 40 CFR Part 52, Subpart E, the permittee shall perform an initial stack test on each Combustion Turbine/HRSG with Duct Burner stack for PM/PM_{10} to demonstrate compliance with the limits specified in Specific Condition #1, 2, and 3. Testing shall be performed every five years in accordance with Plantwide Condition #3 and EPA Reference Method 5 as found in 40 CFR Part 60, Appendix A. Testing shall be performed at or near maximum operating load.

10. Pursuant to §19.703 of Regulation 19, 40 CFR Part 52, Subpart E, 40 CFR Part 60, Subpart GG, 40 CFR Part 75, Subpart B and A.C.A. §8- 4-203 as referenced by §8-4-304 and §8-4-311, monitoring requirements relative to SO_2 emissions from the Combustion Turbine/HRSG shall be as follows:

    A. The permittee shall monitor the natural gas fuel sulfur content daily (unless an alternative monitoring plan is approved by the U.S. EPA).

    B. The permittee shall conduct SO_2 emission monitoring procedures in accordance with Appendix D of 40 CFR Part 75. 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_2 per million Btu of heat input.

    C. The permittee shall maintain records which demonstrate compliance with Specific Condition #10(A) and (B).

11. Pursuant to §19.702 and §19.901 of Regulation 19, and 40 CFR Part 52, Subpart E, the permittee shall perform an initial stack test on each Combustion Turbine/HRSG with Duct Burner stack for VOC to demonstrate compliance with the limits specified in Specific Condition #1 and 3. Testing shall be performed every five years in accordance with Plantwide Condition #3 and EPA Reference Method 25A as found in 40 CFR Part 60, Appendix A. Testing shall be performed at or near maximum operating load.

12. Pursuant to §19.702 and §19.901 of Regulation 19, and 40 CFR Part 52, Subpart E, the permittee shall perform an initial stack test on each Combustion Turbine/HRSG with Duct Burner stack for CO to demonstrate compliance with the limits specified in Specific Condition #1 and 3. Testing shall be performed every five years in accordance with Plantwide Condition #3 and EPA Reference Method 10 as found in 40 CFR Part 60, Appendix A. Testing shall be performed at or near maximum operating load.

13. Pursuant to §19.703 and §19.901 of Regulation 19, 40 CFR Part 52, Subpart E, and A.C.A. §8- 4-203 as referenced by §8-4-304 and §8-4-311, 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_2 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 #1 and #3.

14. Pursuant to §19.702 and §19.901 of Regulation 19, and 40 CFR Part 52, Subpart E, the permittee shall perform an initial stack test on each Combustion Turbine/HRSG with Duct Burner stack for NO_x to demonstrate compliance with the limits specified in Specific Condition #1 and 3. Testing shall be performed every five years in accordance with Plantwide Condition #3 and EPA Reference Method 7E as found in 40 CFR Part 60, Appendix A. Testing shall be performed at or near maximum operating load.

15. Pursuant to §19.703 of Regulation 19, 40 CFR Part 52, Subpart E, 40 CFR Part 60, Subpart GG, 40 CFR Part 75, Subpart B and A.C.A. §8- 4-203 as referenced by §8-4-304 and §8-4-311, monitoring requirements relative to NO_x emissions from the Combustion Turbine/HRSG shall be as follows:

    A. The permittee shall install, calibrate, maintain, and operate a NO_x CEMS on each Combustion Turbine/HRSG with Duct Burner stack. The CEMS shall comply with 40 CFR Part 75. The permittee shall use the measured concentrations of NO_x and O_2 in the flue gas along with the measured fuel flow (or another 40 CFR Part 75 procedure) to calculate NO_x mass emissions. The CEMS shall be used to demonstrate compliance with the NO_x mass emission limits in Specific Condition #1 and #3.

    B. The permittee shall monitor fuel nitrogen content (The permittee shall use the fuel monitoring protocol contained in Appendix A).

    C. The permittee shall maintain records which demonstrate compliance with Specific Condition #15(A).

16. Pursuant to §19.901 of Regulation 19 et seq, 40 CFR Part 52, Subpart E, §19.304 of Regulation 19, and 40 CFR Part 75, CEMS shall be used to demonstrate compliance with the emission limits in Specific Condition #1 and NO_x ppm limits listed in Specific Condition #3.

17. Pursuant to §18.1002 of Regulation 18, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, the permittee shall perform an initial stack test on one of the Combustion Turbine/HRSG with Duct Burner stacks for formaldehyde, 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 every five years in accordance with Plantwide Condition #3 and EPA Reference Method 18 as found in 40 CFR Part 60, Appendix A. Testing shall be performed at or near maximum operating load.

New Source Performance Standards

18. Pursuant to §19.304 of Regulation 19, and 40 CFR Part 60, Subpart GG, the Combustion Turbine/HRSG system (SN-01 and SN-02) is subject. The permittee shall comply with all applicable provisions of 40 CFR Part 60, Subpart A - General Provisions and Subpart GG - Standards of Performance for Stationary Gas Turbines. A copy of Subpart GG is provided in Appendix A. Applicable provisions of Subpart GG include, but are not limited to the following:

    A. Pursuant to 40 CFR §60.332(a)(1), NO_x emissions shall not exceed 163.1 ppmvd at 15% O_2 at ISO conditions. This condition will be met by complying with Specific Condition #3.

    B. Pursuant to 40 CFR §60.333(b), no fuel shall be fired at SN-01 or SN-02 that contains sulfur in excess of 0.8 percent by weight.

    C. Pursuant to 40 CFR §60.334(b), the sulfur content of the natural gas fired at SN-01 and SN-02 shall be initially sampled daily for a period of two weeks to establish that the pipeline quality natural gas fuel supply is low in sulfur content.

    D. Pursuant to 40 CFR §60.334(c)(1), periods of excess emissions for NO_x is defined as any period during which the fuel-bound nitrogen in the fuel is greater than the maximum nitrogen content allowed per the performance test. A report of excess emissions shall include the average fuel consumption, ambient conditions, gas turbine load, nitrogen content of the fuel during the period of excess emissions, and copies of any graphs/figures developed during the performance testing.

    E. Pursuant to 40 CFR §60.334(c)(2), periods of excess emissions for SO_2 is defined as any daily period during which the sulfur content of the fuel being fired exceeds 0.8 percent.

    F. Pursuant to 40 CFR §60.335 and §60.8, initial compliance testing for NO_x and SO_2 is required within 180 days after start-up. The SO_2 demonstration required will be analysis of the sulfur content of the natural gas using ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81. The NOx testing shall be conducted in accordance with testing methods in 40 CFR Part 60 Appendix A or alternative approved methods. The testing shall be conducted for each fuel, at four points in the normal operating range of the turbine.

G. The monitoring and testing requirements of Specific Condition #18(C) and #18(F) are waived if EPA approves the use of 40 CFR Part 75 NO_x CEMS monitoring procedures as an alternative to these requirements. If this approval is granted, excess emissions reporting per Specific Condition #18(D) shall be based on the 40 CFR Part 75 CEMS data.

19. Pursuant to §19.304 of Regulation 19, and 40 CFR Part 60, Subpart Da, the Duct Burners in the Combustion Turbine/HRSG system (SN-01 and SN-02) are subject. The permittee shall comply with all applicable provisions of 40 CFR Part 60, Subpart A - General Provisions and Subpart Da - Standards of Performance for Electric Utility Steam Generating Units. A copy of Subpart Da is provided in Appendix B. Applicable provisions of Subpart Da include, but are not limited to the following:

A. Pursuant to §60.42a(a), no gases shall be discharged into the atmosphere which contain particulate matter in excess of 0.03 lb/million Btu heat input.

B. Pursuant to §60.42a(b), no gases shall be discharged into the atmosphere which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour or not more than 27 percent opacity.

C. Pursuant to §60.43a(b) and (g), no gases shall be discharged into the atmosphere which contain sulfur dioxide in excess of 0.20 lb/million Btu heat input based on a 30-day rolling average. During the performance test, one sampling site shall be located as close as practicable to the exhaust of the turbine. A second sampling site shall be located at the outlet to the steam generating unit. Measurements of sulfur dioxide shall be taken at both sampling sites during the performance test. The sulfur dioxide emission rate from the combined cycle system shall be calculated by subtracting the sulfur dioxide emission rate measured at the sampling site and at the outlet from the turbine from the sulfur dioxide emission rate measured at the sampling site at the outlet from the steam generating unit.

D. Pursuant to §60.44a(d)(1), no gases shall be discharged into the atmosphere which contain nitrogen oxides in excess of 1.6 lb/megawatt-hour gross energy output based on a 30-day rolling average. During the performance test, one sampling site shall be located as close as practicable to the exhaust of the turbine. A second sampling site shall be located at the outlet to the steam generating unit. Measurements of nitrogen oxides and oxygen shall be taken at both sampling sites during the performance test. The nitrogen oxides emission rate from the combined cycle system shall be calculated by subtracting the nitrogen oxides emission rate measured at the sampling site and at the outlet from the turbine from the nitrogen oxides emission rate measured at the sampling site at the outlet from the steam generating unit.

E. Pursuant to §60.46a(c), the particulate matter and nitrogen oxide emission standards apply at all times except during periods of startup, shutdown, or malfunction. The sulfur dioxide emission standards apply at all times except during periods of startup and shutdown.

F. Pursuant to §60.46a(e), compliance with the sulfur dioxide and nitrogen oxide emission limitations is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-day average emission rate for both sulfur dioxide and nitrogen oxides are calculated to show compliance with the standards.

G. Pursuant to §60.46a(i), nitrogen oxide emissions shall be calculated by multiplying the average hourly flow rate and divided by the average hourly gross heat rate and measured according to §60.47a(k).

H. Pursuant to §60.47a(c), the permittee shall install, calibrate, maintain, and operate a continuous monitoring system for NO_x, and record the output of the system. If CEMS are installed to meet the requirements of part 75 and is continuing to meet the requirements of part 75, that CEMS may be used to meet this condition, except that the permittee shall also meet the requirements of §60.49a.

I. Pursuant to §60.47a(d), the permittee shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

J. Pursuant to 40 CFR Part 60, Subpart Da, initial compliance testing for PM/PM_{10}, opacity, and NO_x (at 100% boiler load) is required within 180 days after startup. Testing shall be conducted in accordance with the test methods in 40 CFR Part 60 Appendix A or alternative approved methods.

20. Pursuant to 40 CFR §60.7(a), 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.

Acid Rain Program

21. Pursuant to §19.304 of Regulation 19, 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).

22. Pursuant to §19.304 of Regulation 19, and 40 CFR Part 75 - Continuous Emission Monitoring Subpart G, the submission of the NO_x, SO_2, and O_2 or CO_2 monitoring plans and notice of CEMS initial certification testing is required at least 45 days prior to the CEMS initial certification testing.

23. Pursuant to §19.304 of Regulation 19, and 40 CFR Part 75 - Continuous Emission Monitoring Subpart G, a monitoring plan is required to be submitted for NO_x, SO_2 and O_2 or CO_2 monitoring.

24. Pursuant to §19.304 of Regulation 19, and 40 CFR Part 75 Subpart A, the initial NO_x, SO_2 and O_2 or CO_2 CEMS certification testing is to occur no later than 90 days after the unit commences commercial operation.

25. Pursuant to §19.304 of Regulation 19, and 40 CFR §75.10, 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.

SN-03
Auxiliary Boiler

Source Description

One natural gas fired, low NO_x 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. Use of the boiler will be limited to 1,000 hours per year. Due to the limited use and resulting low emissions, no add-on control devices are required for any regulated pollutants.

Specific Conditions

26. Pursuant to §19.501 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E, 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 Condition #29 through #32.

Pollutant	lb/hr	tpy
PM_{10}	0.7	0.3
SO_2	0.2	0.1
VOC	0.5	0.3
CO	7.0	3.5
NO_X	4.2	2.1

27. Pursuant to §18.801 of the Arkansas Air Pollution Control Code (Regulation #18) effective February 15, 1999, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, 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 Condition #29 through #32.

Pollutant	lb/hr	tpy
PM	0.7	0.3
Formaldehyde	0.1	0.1
Hexane	0.2	0.1

28. Pursuant to §19.304 of Regulation 19, and 40 CFR Part 60, Subpart Dc, the Auxiliary Boiler (SN-03) is subject. 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:

    A. Pursuant to §60.48c(a), the owner or operator shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup. This notification shall include:

        1. The design heat input capacity of the boiler and identification of fuels to be combusted in the affected facility.

        2. The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired.

    B. Pursuant to §60.48c(g) and (i), 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.

29. Pursuant to §18.1004 of Regulation #18, §19.705 and §19.901 et seq of Regulation #19, 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, the auxiliary boiler may only fire pipeline natural gas.

30. Pursuant to §19.705 of Regulation 19, and 40 CFR Part 52, Subpart E, the permittee shall maintain monthly records which demonstrate compliance with Specific Condition #29. 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.

31. Pursuant to §18.1004 of Regulation #18, §19.705 and §19.901 et seq of Regulation #19, 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, operation of the auxiliary boiler shall be limited to 1000 hours per twelve consecutive months.

32. Pursuant to §19.705 of Regulation 19, and 40 CFR Part 52, Subpart E, the permittee shall maintain monthly records which demonstrate compliance with Specific Condition #31. 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.

33. Pursuant to §19.901 of Regulation 19 et seq, and 40 CFR Part 52, Subpart E, 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 #29 and #31.

Pollutant	BACT Determination	
PM/PM_{10}	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_x	Low NO_x Burner	0.04 lb/MMBtu

34. Pursuant to §19.702 and §19.901 of Regulation 19, and 40 CFR Part 52, Subpart E, the permittee shall perform an initial stack test on the auxiliary boiler (SN-03) for NO_x to demonstrate compliance with the limits specified in Specific Condition #33. Testing shall be performed in accordance with Plantwide Condition #3 and EPA Reference Method 7E as found in 40 CFR Part 60, Appendix A. Testing shall be performed at or near maximum operating load.

SN-04 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-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

35. Pursuant to §19.501 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E, 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 Condition #37 through #39.

Source	Pollutant	lb/hr	tpy
SN-04 to SN-15	PM_{10}	0.6	2.3
SN-16 to SN-27	PM_{10}	0.1	0.4

36. Pursuant to §18.801 of the Arkansas Air Pollution Control Code (Regulation #18) effective February 15, 1999, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, 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 Condition #37 through #39.

Source	Pollutant	lb/hr	tpy
SN-04 to SN-15	PM	3.9	16.9
SN-16 to SN-27	PM	0.2	0.6

37. Pursuant to §18.501 of Regulation #18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, the permittee shall not cause to be discharged to the atmosphere from the cooling tower stack gases which exhibit an opacity greater than 20%. Compliance with this opacity limit shall be demonstrated by Specific Condition #38.

38. Pursuant to §19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6, the total dissolved solids concentration for SN-04 through SN-15 shall not exceed 8,000 parts per million in the water.

39. Pursuant to §19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6, the total dissolved solids concentration for SN-16 through SN-27 shall not exceed 1,500 parts per million in the water.

40. Pursuant to §19.705 of Regulation 19, and 40 CFR Part 52, Subpart E, the permittee shall monitor weekly the total dissolved solids concentration to demonstrate compliance with

Specific Conditions #38 and #39. 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 Condition #7.

41. Pursuant to §19.901 of Regulation 19 et seq, and 40 CFR Part 52, Subpart E, 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 Condition #38 and #39.

Pollutant	BACT Determination	
PM/PM_{10}	Drift Eliminators and Good Operating Practices	0.0005% Drift from the water flow

SN-23
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

42. Pursuant to §19.501 et seq of the Regulations of the Arkansas Plan of Implementation for Air Pollution Control (Regulation #19) effective February 15, 1999 and 40 CFR Part 52, Subpart E, 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 Condition #43 through #48.

Pollutant	lb/hr	tpy
PM_{10}	0.6	0.1
SO_2	0.5	0.1
VOC	0.7	0.1
CO	1.7	0.2
NO_X	7.6	1.0

43. Pursuant to §18.801 of the Arkansas Air Pollution Control Code (Regulation #18) effective February 15, 1999, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, 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 Condition #43, #44, #47 and #48.

Pollutant	lb/hr	tpy
PM	0.6	0.1
Formaldehyde	0.1	0.1

44. Pursuant to §19.503 of Regulation 19, and 40 CFR Part 52, Subpart E, the permittee shall not cause to be discharged to the atmosphere from the diesel fired emergency generator gases which exhibit an opacity greater than 20%.

45. Pursuant to §19.705 of Regulation 19, and 40 CFR Part 52, Subpart E, daily observations of the opacity from source SN-23 shall be conducted by a person trained in EPA Reference Method 9 when the generator is operated more than 3 consecutive hours. If visible emissions appear to be in excess of 20%, the permittee shall immediately take action to identify the cause of the excess visible emissions, implement corrective action, and document that visible emissions do not appear to be in excess of the permitted opacity following the corrective action. The permittee shall maintain records of any visible emissions which appeared to be in excess of the permitted opacity, the corrective action taken, and if visible emissions were present following the corrective action. These records shall be kept on site, and shall be made available to Department personnel upon request. Each opacity record shall be submitted in accordance with General Condition #7.

46. Pursuant to §18.1004 of Regulation #18, §19.705 and §19.901 et seq of Regulation #19, 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, the emergency generator may only fire diesel fuel containing a maximum of 0.5% sulfur.

47. Pursuant to §19.705 of Regulation 19, and 40 CFR Part 52, Subpart E, the permittee shall maintain monthly records which demonstrate compliance with Specific Condition #45. 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 Condition #7.

48. Pursuant to §18.1004 of Regulation #18, §19.705 and §19.901 et seq of Regulation #19, 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, operation of the emergency generator shall be limited to 250 hours per twelve consecutive months.

49. Pursuant to §19.705 of Regulation 19, and 40 CFR Part 52, Subpart E, 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. A twelve month rolling total and each individual month's data shall be submitted in accordance with General Condition #7.

SN-28 to SN-31
Wastewater Cooling Tower

Source Description

The waste-water cooling system is part of the zero-liquid water discharge system. It consists of a four cell mechanical draft cooling tower (SN-28 through SN-31). It uses heat from the main cooling system to concentrate plant effluent. The concentrated “brine” is then forwarded to a forced circulation crystallizer for complete water removal and disposal in a solid form.

Specific Conditions

50. Pursuant to §19.501 et. seq. of Regulation 19 and 40 CFR Part 52, Subpart E, 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 Condition #53.

Pollutant	lb/hr	tpy
PM_{10}	0.1	0.1

51. Pursuant to §18.801 of the Arkansas Air Pollution Control Code (Regulation 18) and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, 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 Condition #53.

Pollutant	lb/hr	tpy
PM	0.8	3.3

52. Pursuant to §18.501 of Regulation #18 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, the permittee shall not cause to be discharged to the atmosphere from any cooling tower stack gases which exhibit an opacity greater than 20%.

53. Pursuant to §19.705 of Regulation 19, A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, and 40 CFR 70.6, the total suspended particulate concentration for SN-28 through SN-31 shall not exceed 75,000 parts per million in the water. Compliance shall be demonstrated through compliance with Specific Condition #54.

54. Pursuant to §19.705 of Regulation 19, and 40 CFR Part 52, Subpart E, the permittee shall monitor weekly the total suspended particulate concentration to demonstrate compliance with the above condition. 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 copy of these records shall be submitted in accordance with General Provision #7.

SECTION V: COMPLIANCE PLAN AND SCHEDULE

TPS - Dell is in compliance with the applicable regulations cited in the permit application. TPS - Dell 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. Pursuant to §19.704 of Regulation 19, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, the Director shall be notified in writing within thirty (30) days after construction has commenced, construction is complete, the equipment and/or facility is first placed in operation, and the equipment and/or facility first reaches the target production rate.

2. Pursuant to §19.410(B) of Regulation 19, 40 CFR Part 52, Subpart E, the Director may cancel all or part of this permit if the construction or modification authorized herein is not begun within 18 months from the date of the permit issuance or if the work involved in the construction or modification is suspended for a total of 18 months or more.

3. Pursuant to §19.702 of Regulation 19 and/or §18.1002 of Regulation 18 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, any equipment that is to be tested, unless stated in the Specific Conditions of this permit or by any federally regulated requirements, shall be tested with the following time frames: (1) Equipment to be constructed or modified shall be tested within sixty (60) days of achieving the maximum production rate, but in no event later than 180 days after initial start-up of the permitted source or (2) equipment already operating shall be tested according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee shall notify the Department of the scheduled date of compliance testing at least fifteen (15) days in advance of such test. Compliance test results shall be submitted to the Department within thirty (30) days after the completed testing.

4. Pursuant to §19.702 of Regulation 19 and/or §18.1002 of Regulation 18 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311, the permittee shall provide:

    a. Sampling ports adequate for applicable test methods
    b. Safe sampling platforms
    c. Safe access to sampling platforms
    d. Utilities for sampling and testing equipment

5. Pursuant to §19.303 of Regulation 19 and A.C.A. §8-4-203 as referenced by A.C. A. §8-4-304 and §8-4-311, the equipment, control apparatus and emission monitoring equipment shall be operated within their design limitations and maintained in good condition at all times.

6. Pursuant to Regulation 26 and A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, this permit subsumes and incorporates all previously issued air permits for this facility.

Acid Rain (Title IV)

7. Pursuant to §26.701 of Regulation #26 and 40 CFR 70.6(a)(4), the permittee is prohibited from causing any emissions which exceed any allowances that the source lawfully holds under Title IV of the Act or the regulations promulgated thereunder. No permit revision is required for increases in emissions that are authorized by allowances acquired pursuant to the acid rain program, provided that 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. The source may not, however, use allowances as a defense to noncompliance with any other applicable requirement of this permit or the Act. Any such allowance shall be accounted for according to the procedures established in regulations promulgated under Title IV of the Act.

Title VI Provisions

8. The permittee shall comply with the standards for labeling of products using ozone depleting substances pursuant to 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.

9. The permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F, except as provided for MVACs in Subpart B:

    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.

10. 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.

11. 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.

12. The permittee shall be allowed to switch from any ozone-depleting substance to any alternative that is listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR part 82, Subpart G, Significant New Alternatives Policy Program.

SECTION VII: INSIGNIFICANT ACTIVITIES

Pursuant to §26.3(d) of Regulation 26, the following sources are insignificant activities. Insignificant and trivial activities will be allowable after approval and federal register notice publication of a final list as part of the operating air permit program. Any activity for which a state or federal applicable requirement applies is not insignificant even if this activity meets the criteria of §3(d) of Regulation 26 or is listed below. Insignificant activity determinations rely upon the information submitted by the permittee in an application dated August 3, 2001.

Description	Category
379 bhp Diesel Fire Water Pump Engine	Group B, Number 47
Diesel Storage Tanks	Group A, Number 3
Four small fuel heaters (4.05 MMBtu/hr each)	Group A, Number 1

Pursuant to §26.304 of Regulation 26, the emission units, operations, or activities contained in Regulation 19, Appendix A, Group B, have been determined by the Department to be insignificant activities. Activities included in this list are allowable under this permit and need not be specifically identified.

SECTION VIII: GENERAL PROVISIONS

1. Pursuant to 40 C.F.R. 70.6(b)(2), 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.

2. Pursuant to 40 C.F.R. 70.6(a)(2) and §26.7 of the Regulations of the Arkansas Operating Air Permit Program (Regulation 26), 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.

3. Pursuant to §26.4 of Regulation #26, it is the duty of the permittee to submit a complete application for permit renewal at least six (6) months prior to the date of permit expiration. Permit expiration terminates the permittee's right to operate unless a complete renewal application was submitted at least six (6) months prior to permit expiration, in which case the existing permit shall 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.

4. Pursuant to 40 C.F.R. 70.6(a)(1)(ii) and §26.7 of Regulation #26, 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, both provisions are incorporated into the permit and shall be enforceable by the Director or Administrator.

5. Pursuant to 40 C.F.R. 70.6(a)(3)(ii)(A) and §26.7 of Regulation #26, records of monitoring information required by this permit shall include the following:

    a. The date, place as defined in this permit, and time of sampling or measurements;
    b. The date(s) analyses were performed;
    c. The company or entity that performed 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.

6. Pursuant to 40 C.F.R. 70.6(a)(3)(ii)(B) and §26.7 of Regulation #26, records of all required monitoring data and support information shall be retained for a period of at least 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.

7. Pursuant to 40 C.F.R. 70.6(a)(3)(iii)(A) and §26.7 of Regulation #26, the permittee shall submit reports of all required monitoring every 6 months. If no other reporting period has been established, the reporting period shall end on the last day of the anniversary month of this permit. The report shall be due within 30 days of the end of the reporting period. Even though the reports are due every six months, each report shall contain a full year of data. All instances of deviations from permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official as defined in §26.2 of Regulation #26 and must be sent to the address below.

    Arkansas Department of Environmental Quality
    Air Division
    ATTN: Compliance Inspector Supervisor
    Post Office Box 8913
    Little Rock, AR 72219

8. Pursuant to 40 C.F.R. 70.6(a)(3)(iii)(B), §26.7 of Regulation #26, and §19.601 and 19.602 of Regulation #19, all deviations from permit requirements, including those attributable to upset conditions as defined in the permit shall be reported to the Department. An initial report shall be made to the Department by the next business day after the occurrence. The initial report may be made by telephone and shall include:

9. Pursuant to 40 C.F.R. 70.6(a)(5) and §26.7 of Regulation #26, and A.C.A.§8-4-203, as referenced by §8-4-304 and §8-4-311, if any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity shall 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.

10. Pursuant to 40 C.F.R. 70.6(a)(6)(i) and §26.7 of Regulation #26, 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, or modification; or for denial of a permit renewal application. Any permit noncompliance with a state requirement constitutes a violation of the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 *et seq*.) and is also grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

11. Pursuant to 40 C.F.R. 70.6(a)(6)(ii) and §26.7 of Regulation #26, 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 in order to maintain compliance with the conditions of this permit.

12. Pursuant to 40 C.F.R. 70.6(a)(6)(iii) and §26.7 of Regulation #26, this permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

13. Pursuant to 40 C.F.R. 70.6(a)(6)(iv) and §26.7 of Regulation #26, this permit does not convey any property rights of any sort, or any exclusive privilege.

14. Pursuant to 40 C.F.R. 70.6(a)(6)(v) and §26.7 of Regulation #26, the permittee shall 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 shall also furnish to the Director copies of records required to be kept by the permit. For information claimed to be confidential, the permittee may be required to furnish such records directly to the Administrator along with a claim of confidentiality.

15. Pursuant to 40 C.F.R. 70.6(a)(7) and §26.7 of Regulation #26, the permittee shall pay all permit fees in accordance with the procedures established in Regulation #9.

16. Pursuant to 40 C.F.R. 70.6(a)(8) and §26.7 of Regulation #26, no permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for elsewhere in this permit.

17. Pursuant to 40 C.F.R. 70.6(a)(9)(i) and §26.7 of Regulation #26, if the permittee is allowed to operate under 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 scenario under which the facility or source is operating.

18. Pursuant to 40 C.F.R. 70.6(b) and §26.7 of Regulation #26, all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, are enforceable by the Administrator and citizens under the Act unless the Department has specifically designated as not being federally enforceable under the Act any terms and conditions included in the permit that are not required under the Act or under any of its applicable requirements.

19. Pursuant to 40 C.F.R. 70.6(c)(1) and §26.7 of Regulation #26, any document (including reports) required by this permit shall contain a certification by a responsible official as defined in §26.2 of Regulation #26.

20. Pursuant to 40 C.F.R. 70.6(c)(2) and §26.7 of Regulation #26, the permittee shall allow an authorized representative of the Department, upon presentation of credentials, to perform the following:

21. Pursuant to 40 C.F.R. 70.6(c)(5) and §26.7 of Regulation #26, the permittee shall submit a compliance certification with terms and conditions contained in the permit, including emission limitations, standards, or work practices. This compliance certification shall be submitted annually and shall be submitted to the Administrator as well as to the Department. All compliance certifications required by this permit shall include the following:

22. Pursuant to §26.7 of Regulation #26, nothing in this permit shall alter or affect the following:

23. Pursuant to A.C.A. §8-4-203 as referenced by §8-4-304 and §8-4-311, this permit authorizes only those pollutant emitting activities addressed herein.

APPENDIX A

APPENDIX B

APPENDIX C

INVOICE REQUEST FORM

PDS-__________

Date ________May 10, 2002____________

X	**Air**
	NPDES
	Stormwater
	State Permits Branch
	Solid Waste

CSN_________47-0448_____________

Facility Name_________GenPower - Dell____________________________________

Invoice Mailing Address_______1040 Great Plain Avenue_____________________

Needham, Massachusetts 02492-2517

	Initial
X	**Modification**
	Annual

Permit Number______1903-AOP-R2__________________
Permit Description ___Title 5____________________
Permit Fee Code_____A_______

Amount Due $ 1000____

Engineer_____Wesley Crouch______

Paid? ☐**No** ☐**Yes Check #**_________

Comments: Air Permit Fee Calculation

Fee Amount = ($19.64)*(TPY increase of all pollutants except CO)
= ($19.64)*(10.8)
= $1,000.00

Public Notice

Pursuant to the Arkansas Operating Air Permit Program (Regulation #26) Section 6(b), the Air Division of the Arkansas Department of Environmental Quality gives the following notice:

TPS Dell, LLC, is constructing a natural gas fired power plant in Dell, Arkansas. This facility will be a combined cycle electrical generating plant with a nominal rating of 528 MW (with a peak of 640 MW), supplying electrical energy to the Entergy Power Grid via the pre-existing Entergy sub-station located adjacent to the planned site. The permit is being modified to update the calculations used to determine the emission rates from the cooling towers and add 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).

The application has been reviewed by the staff of the Department and has received the Department's tentative approval subject to the terms of this notice.

Citizens wishing to examine the permit application and staff findings and recommendations may do so by contacting Doug Szenher, Information Officer. Citizens desiring technical information concerning the application or permit should contact Wesley Crouch, Engineer. Both Doug Szenher and Wesley Crouch can be reached at the Department's central office, 8001 National Drive, Little Rock, Arkansas 72209, telephone: (501) 682-0744.

The draft permit and permit application are available for copying at the above address. A copy of the draft permit has also been placed at the Blytheville Public Library at 200 North Fifth in Blytheville, Arkansas 72315. This information may be reviewed during normal business hours.

Interested or affected persons may also submit written comments or request a hearing on the proposal, or the proposed modification, to the Department at the above address - Attention: Doug Szenher. In order to be considered, the comments must be submitted within thirty (30) days of publication of this notice. Although the Department is not proposing to conduct a public hearing, one will be scheduled if significant comments on the permit provisions are received. If a hearing is scheduled, adequate public notice will be given in the newspaper of largest circulation in the county in which the facility in question is, or will be, located.

The Director shall make a final decision to issue or deny this application or to impose special conditions in accordance with Section 2.1 of the Arkansas Dept. of Environmental Quality Commission's Administrative Procedures (Regulation #8) and Regulation #26.

Dated this

Richard A. Weiss
Interim Director