COMMONWEALTH OF VIRGINIA
Department of Environmental Quality
Valley Regional Office

STATEMENT OF LEGAL AND FACTUAL BASIS

Tenaska Virginia Partners, L.P.
Tenaska Virginia Generating Station
Facility Location: State Route 761, 2.5 miles northeast of Antioch,
Fluvanna County, Virginia
Permit No. VRO40995

Title IV of the 1990 Clean Air Act Amendments required each state to develop a permit program to ensure that certain electrical generation facilities have federal Air Pollution Operating Permits, called Title IV Operating Permits. As required by 40 CFR Part 70, 9 VAC 5 Chapter 80, Article 3 and Chapter 140 of the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution, Tenaska Virginia Partners, L.P. has applied for a renewal of the Title IV Operating Permit for its Tenaska Virginia Generating Station. The Department has reviewed the application and has prepared a Federal Operating Permit. This permit is based upon Federal Clean Air Act Acid Rain permitting requirements of Title IV, federal operating permit requirements of Title V, and Chapter 80, Article 3 and Chapter 140 of the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution

Engineer/Permit Contact: JRP Date: 12/6/12
for Laura R. Justin
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Air Permit Manager: Janardan R Pandey Date: 12/6/12
Janardan R. Pandey, P.E.

FACILITY INFORMATION

Permittee
Tenaska Virginia Partners, L.P.
1044 North 115th Street, Suite 400
Omaha, NE, 68154

Facility
Tenaska Virginia Generating Station
2300 Branch Road
Scottsville, VA 24590
(State Route 761, 2.5 miles northeast of Antioch
Fluvanna County, Virginia)

Plant ID No. 51-065-0021

SOURCE DESCRIPTION

Facility Description: NAICS Code 221112 (Electric Power Generation)

The facility is an electric power generating facility located in Fluvanna County, Virginia. The facility uses three (3) GE Frame 7FA combustion turbines (CTs), three heat recovery steam generators (HRSGs) with duct burners (DBs), and one steam turbine (ST). The CTs are fired on pipeline quality natural gas and can be fired on distillate fuel oil as a backup with a sulfur content of 0.01% or less. The DBs can be fired only on pipeline quality natural gas. The NO_x in the exhaust of the CTs, downstream of the duct burners, shall be controlled by selective catalytic reduction (SCR) with ammonia injection.

The facility is a Title V major source of particulate matter less than or equal to ten microns in diameter (PM-10), volatile organic compounds (VOC), nitrogen oxides (NO_x) and carbon monoxide (CO). This source is located in an attainment area for all pollutants, and is a PSD major source. The facility is currently operating under a PSD permit dated 02/13/2003, as amended 01/30/2006. The facility commenced operation on December 23, 2003. The facility is also subject to the Title IV Acid Rain regulations (9 VAC 5 Chapter 80, Article 3) and the Clean Air Interstate Rule (CAIR) (9 VAC 5 Chapter 140).

COMPLIANCE STATUS

A full compliance evaluation of this facility, including a site visit, was conducted most recently on July 15, 2011. In addition, all reports and other data required by permit conditions or regulations, which are submitted to DEQ, are evaluated for compliance. Based on these compliance evaluations, the facility has not been found to be in violation of any state or federal applicable requirements at this time.

EMISSION UNIT AND CONTROL DEVICE IDENTIFICATION

The emissions units at this facility consist of the following:

Table 1. Emissions units and control devices

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity*	Pollution Control Device (PCD) Description	PCD ID	Pollutant Controlled	Applicable Permit Date
Fuel Burning Equipment							
EU001	SN001	GE Frame 7FA - Combustion Turbine (CT) and Heat Recovery Steam Generator (HRSG) Natural Gas / Distillate Fuel Oil (2003)	CT - 1,858 MMBtu/hr (Natural Gas) CT - 2,020 MMBtu/hr (Distillate Fuel Oil) HRSG - 550 MMBtu/hr (Natural Gas)	Selective Catalytic Reduction	SCR1	NO_x	02/13/2003 Permit as amended 01/30/2006
EU002	SN002	GE Frame 7FA - Combustion Turbine (CT) and Heat Recovery Steam Generator (HRSG) Natural Gas / Distillate Fuel Oil (2003)	CT - 1,858 MMBtu/hr (Natural Gas) CT - 2,020 MMBtu/hr (Distillate Fuel Oil) HRSG - 550 MMBtu/hr (Natural Gas)	Selective Catalytic Reduction	SCR2	NO_x	02/13/2003 Permit as amended 01/30/2006
EU003	SN003	GE Frame 7FA - Combustion Turbine (CT) and Heat Recovery Steam Generator (HRSG) Natural Gas / Distillate Fuel Oil (2003)	CT - 1,858 MMBtu/hr (Natural Gas) CT - 2,020 MMBtu/hr (Distillate Fuel Oil) HRSG - 550 MMBtu/hr (Natural Gas)	Selective Catalytic Reduction	SCR3	NO_x	02/13/2003 Permit as amended 01/30/2006

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity*	Pollution Control Device (PCD) Description	PCD ID	Pollutant Controlled	Applicable Permit Date
EU011	SN011	Emergency Fire Water Pump (2003)	2.8 MMBtu/hr (Distillate Fuel Oil)	-	-	-	02/13/2003 Permit as amended 01/30/2006
Process Equipment							
EU013	SN013	Cooling Tower #1	278,480 gal/min	-	-	-	02/13/2003 Permit as amended 01/30/2006
T001	T001	Distillate Fuel Oil Storage Tank	2.10 MMgal	-	-	-	02/13/2003 Permit as amended 01/30/2006

*The Size/Rated capacity is provided for informational purposes only, and is not an applicable requirement.

EMISSIONS INVENTORY

Annual emissions summarized in the following table are derived from the 2011 annual emission statement. A copy of the report is provided as Attachment A.

Table 2. Plantwide emissions (2011)

2011 Pollutant Emissions (Plantwide Total)	
Pollutant	Tons Emitted
Criteria Pollutants	
PM-10	51.84
PM-2.5	51.84
VOC	9.02
NO_x	119.96
SO_2	9.98
CO	24.41
Hazardous Air Pollutants (HAP)	
Total HAP	2.13

EMISSION UNIT APPLICABLE REQUIREMENTS

Emission Units (EU001, EU002, EU003, EU010 and EU011)

Limitations

The three combustion turbines (CTs) are subject to 40 CFR 60, Subpart GG. The three heat recovery steam generators (HRSGs) with duct burners (DBs) are subject to 40 CFR 60, Subpart Da. The following limitations and/or other applicable requirements are from the PSD permit dated 02/13/2003, as amended 01/30/2006 which includes requirements that are based on 40 CFR Part 60, Subparts GG and Da. Please note that the condition numbers are from the PSD permit dated 02/13/2003, as amended 01/30/2006; a copy of the permit is enclosed as Attachment B.

Condition 3: Requirement that nitrogen oxide emissions from each CT and HRSG duct burner shall be controlled by dry/low-NO_x lean premix burners. The NO_x in the exhaust of the CTs, downstream of the duct burners, shall be controlled by selective catalytic reduction (SCR) with ammonia injection

Condition 4: Requirement that sulfur dioxide emissions from each CT, HRSG duct burner and the fire water pump shall be controlled by the use of low sulfur fuels.

Condition 5: Requirement that sulfuric acid mist emissions from each CT and HRSG duct burner shall be controlled by the use of low sulfur fuels.

Condition 6: Requirement that particulate matter from the cooling tower shall be controlled by the use of drift eliminators.

Condition 8: Limit on distillate fuel oil throughput to each CT.

Condition 9: Limit on natural gas throughput to each CT.

Condition 10: Limit on natural gas throughput to each duct burner.

Condition 11: Limit on distillate fuel oil throughput to the emergency fire water pump.

Condition 12: Limit on the types of fuels to be combusted in the CTs. Natural gas and distillate fuel oil are the only approved fuels.

Condition 13: Limit on the type of fuel to be combusted in the duct burners. Natural gas is the only approved fuel.

Condition 14: Limit on the type of fuel to be combusted in the emergency fire water pump. Distillate fuel oil is the only approved fuel.

Condition 16: Limit on the type of fuel to be stored at the 2.1 million gallon tank.

Condition 17: Emission limits for each CT.

Condition 18: Emission limits for the duct burners.

Condition 19: Emission limits for the emergency fire water pump.

Condition 20: Visible emission limit for the CT/HRSBG stacks of 10%, except during one six-minute period in any hour where visible emissions shall not exceed 20%.

Appendix A: Definitions of Startup, Shutdown, Minimum Load, Fuel transfer, Standard Conditions and Fuel Shipment Sampling

The new source visible emissions limits at 9 VAC 5-50-80 apply to the emergency fire water pump. Accordingly, the following limitations are included in the operating permit:

- Visible emission limit for the emergency fire water pump of 20%, except during one six-minute period in any hour where visible emissions shall not exceed 30%.

The emergency fire water pump is subject to the requirements in 40 CFR 63 Subpart ZZZZ (National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Reciprocating Internal Combustion Engines (RICE)) for compression ignition (CI) engines located at area sources. The compliance date for emergency CI engines at area sources is May 3, 2013. Accordingly, the following requirements for the emergency fire water pump from 40 CFR 63 Subpart ZZZZ have been included in the draft renewal operating permit.

- Change oil and filter every 500 hours of operation or annually, whichever comes first, or at an extended frequency if utilizing an oil analysis program as described in 40 CFR 63.6625(i);

- Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first;

- Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary;

- Operate and maintain the emergency firewater pump according to the manufacturer's emission-related written instructions or the permittee may develop its own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions;

- Install a non-resettable hour meter if one is not already installed;

- During periods of startup, minimize the time spent at idle for the emergency firewater pump and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes;

- Keep records of maintenance conducted on the firewater pump and annual hours of operation (both emergency and non-emergency)

- Reports of deviations from 40 CFR 63 Subpart ZZZZ requirements

Monitoring

The monitoring requirements in Conditions 7, 15, 25, 26, 29 of the PSD permit dated 02/13/2003, as amended 01/30/2006, have been included to meet 40 CFR Parts 70 and 75 requirements. The following additional monitoring requirements related to selective catalytic reduction (SCR) are included in the operating permit:

– Each SCR system shall be equipped with devices to continuously measure and record ammonia feed rate and catalyst bed inlet gas temperature. The devices used to continuously measure ammonia feed rate and catalyst bed inlet gas temperature shall be observed by the permittee with a frequency sufficient to ensure good performance of the SCR system but not less than once per day of operation.

The permittee is required to keep records of the fuel combusted for each combustion turbine, which will satisfy the periodic monitoring requirements for the fuel throughput limits.

The permittee is required to install continuous emission monitoring systems to measure and record the concentration of NO_x emitted by each combustion turbine and its duct burner. This will satisfy the periodic monitoring requirement for the NO_x emission limits contained within the permit for the three combustion turbines.

The permittee is also required to monitor SO_2 with the use of fuel monitoring and sulfur sampling and analysis procedures that comply with the requirements of 40 CFR Part 75, Appendix D (Acid Rain program monitoring). The approved fuels for the combustion turbines are natural gas with a maximum sulfur content of 0.6 grains per 100 dry standard cubic feet and distillate fuel oil with a maximum sulfur content of 0.01 percent by weight, and the approved fuel for the duct burner is natural gas. This will satisfy the periodic monitoring requirement for the SO_2 emission limits contained within the permit for the three combustion turbines.

With the exception of NO_x and SO_2 emissions, actual short-term emissions from the operation of the combustion turbines and duct burners will be determined based on the most recent DEQ-approved stack test, results of which are shown below (Table 3). It is noted that this data may not reflect more recent stack testing performed during the permit term and therefore may not match actual emission factors being used at any given time.

Table 3. Emission factors from stack testing (all factors in lbs/hr)

Pollutant	Fuel	CT1			CT2			CT3		
		Min Load	Base Load		Min Load	Base Load		Min Load	Base Load	
		DB Off	DB Off	DB On	DB Off	DB Off	DB On	DB Off	DB Off	DB On
CO	Gas	0.44	1.6	3.74	2.15	2.18	10.65	1.92	3.4	1.5
	Oil	N/A	2.54	N/A	N/A	2.11	N/A	N/A	1.72	N/A
PM	Gas	N/A	2.6	3.5	N/A	9.3	10.5	N/A	3.5	9
	Oil	N/A	12.32	N/A	N/A	15.15	N/A	N/A	12.06	N/A
VOC	Gas	0.58	0.83	1.1	0.9	0.87	0.75	0.5	0.8	1.9
	Oil	N/A	0.95	N/A	N/A	0.61	N/A	N/A	1.39	N/A

Actual annual emissions of CO, PM and VOC will be calculated based on the hourly rate determined in stack testing multiplied by the hours of operation for each rolling 12-month period. Alternatively, lbs/MMBtu emission factors may be used with actual heat input data to derive actual hourly emission rates. Detailed stack test information (including test dates) was summarized and provided by Tenaska and is attached (Attachment C).

Based on the types of fuel to be combusted in the turbines and duct burners, there is little likelihood of violating the opacity limitation (The approved fuels for the combustion turbines are natural gas with a maximum sulfur content of 0.6 grains per 100 dry standard cubic feet and distillate fuel oil with a maximum sulfur content of 0.01 percent by weight, and the approved fuel for the duct burner is natural gas). Therefore, as long as the combustion turbines are operated properly it can be assumed that the opacity limitation will not be violated. Observation of the three CT stacks while operating during the most recent full compliance inspection by DEQ staff (July 18, 2011) resulted in a finding of no visible emissions (0% opacity)). Maintenance of operating procedures and performance of maintenance in accordance with the maintenance schedule will ensure compliance with the opacity limitation in the permit.

The permittee shall conduct at least once a week an inspection of each CT/HRSBG stack to determine the presence of visible emissions. If during the inspection visible emissions are observed, the permittee has one of the following options: (1) The permittee takes timely corrective action such that the affected unit resumes normal operation and there are no visible emissions from the exhaust stack, or (2) the permittee has the option to conduct a Method 9 VEE to determine whether visible emissions from the affected unit exceeded 10% opacity. If the facility chooses the Method 9 VEE, then the VEE shall be conducted for a minimum of six minutes. If any of the observations exceed 10%, the VEE shall be conducted for a total of 60 minutes. If compliance is not demonstrated by this VEE, timely corrective action shall be taken such that the affected unit resumes operation with visible emissions of 10% or less. The weekly inspections will also satisfy the periodic monitoring requirement for the visible emission limitation.

Sulfuric Acid Mist (H_2SO_4) emissions from each CT and HRSG duct burner shall be controlled by the use of low sulfur fuels (pipeline quality natural gas and low sulfur distillate fuel oil). The permittee is required to keep fuel analysis records or supplier certifications sufficient to demonstrate the maximum sulfur content limit of the fuels combusted. Tenaska is also required to keep records of emissions calculations sufficient to verify compliance with the emission limitations in the permit. This will satisfy the periodic monitoring requirement for the H_2SO_4 emissions limit contained within the permit.

Actual emissions from the operation of the emergency fire water pump will be calculated using the following equation:

$$E = F \times P \qquad \text{Equation 3}$$

Where:

E	=	Emission Rate (lb/time period)
F	=	Pollutant specific emission factors as recommended by the manufacturer:
		NO_x = 1.94 lb/MMBtu
P	=	distillate fuel oil consumed (MMBtu/time period)

The hourly emission limit established for NO_x is based on the capacity of the pump. Therefore, if the pump is operated at capacity or below, there should not be a violation of the hourly emission rate. The annual emission limit established for NO_x is based on the fuel usage limit (equivalent to 500 hrs/yr) contained within the permit. The fuel throughput is the factor that determines the emission rates. If Tenaska does not violate the throughput limit contained in the permit, the pollutant emission limits will not be violated. Therefore, there is very little chance that the pollutant emission limits will be violated. Recordkeeping demonstrating the total amount of oil combusted each year can be used to demonstrate compliance with the pollutant emission limits, satisfying the periodic monitoring requirement.

Compliance Assurance Monitoring (CAM) Plan

The combustion turbines (CTs) utilize SCR systems to reduce NO_x emissions. Both potential uncontrolled and controlled NO_x emissions from the CT exceed 100 tpy. Thus, the CTs meet the applicability definition for CAM and would be required to submit a CAM plan for NO_x. However, the CAM regulations also provide specific exemptions from the regulations. One such exemption is for sources with a continuous compliance determination method, such as usage of a CEMS (see 40 CFR 64.2(b)(1)(vi)). The current PSD permit requires that a NO_x CEMS be installed and operated continuously on the exhaust stack for each CT to determine compliance with the NO_x emission limits. This requirement of a NO_x CEMS is also included in the operating permit. Hence, the CTs are exempt from CAM for NO_x emissions. Also, the CTs are not subject to CAM for any other pollutants as there are no add-on control devices for any other pollutants.

No other emission units at the facility utilize active control devices. Therefore, CAM is not applicable to any emission unit at the Tenaska Virginia Generating Station.

Recordkeeping

The permit includes requirements for maintaining records of all monitoring and testing required by the PSD permit dated 02/13/2003, as amended 01/30/2006. These records include the annual fuel throughputs of natural gas and distillate fuel oil, fuel supplier certifications, DEQ-approved emission factors and equations to demonstrate compliance with emission limits in the permit, visible emissions observation results for each CT and duct burner, CEM records, operator training and maintenance records, and performance tests and VEEs.

Testing

Initial performance testing was required for SO_2, NO_x, CO, PM_{10} (including condensible PM) and VOC from each GE 7FA CT and associated duct burner in the PSD permit to comply with the emission limits. The facility conducted these stack tests in 2004. Concurrent with initial performance tests, VEE were also required for each CT and associated duct burner. Stack test results (see Attachment C) showed that the facility complied with these emission limits.

In order to provide further assurance that the CO emission limits contained in Condition 14 of the operating permit are met, Tenaska shall conduct a once per permit term performance test for CO as detailed in Condition 34 of the operating permit.

Tenaska may conduct performance testing for CO from each turbine to establish a new minimum load, as indicated in Condition 35 of the operating permit. This new minimum load will allow the combustion turbines to steadily operate at a load percent that is below the initial minimum load level of 50%.

The Department and EPA have authority to require testing not included in this permit if necessary to determine compliance with an emission limit or standard.

Reporting

The permit requires semi-annual reporting of excess emissions. Each report shall be postmarked no later than the 30th day following the end of each semi-annual period.

40 CFR 60.7 (c) requires semi-annual reporting for excess emissions unless an applicable subpart requires more frequent reporting. 40 CFR 60 Subpart GG required quarterly reporting at the time of issuance of the PSD permit (see Condition 27 of the 1/30/06 PSD permit), but has since been revised to require semi-annual reporting (see 40 CFR 60.334(g)). The reporting frequency in the PSD permit will be changed to semi-annual during the next amendment.

Streamlined Requirements

The Combustion Turbines have the following applicable requirements from the NSPS (40 CFR 60) Subpart GG and 9 VAC 5-50-410:

§60.332 (a)(1): Allowable NO_x emissions shall not exceed the following:

$$STD = 0.0075\ (14.4/Y) + F$$

where:

STD = allowable ISO corrected NO_x emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = Manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. = 9.9 kilojoules per watt hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined in §60.332 (a)(3) = 0

Allowable NO_x emissions per Subpart GG = 109 ppmvd

The allowable NO_x emission limit in the PSD permit (3.0 ppmvd on gas and 6.0 ppmvd on oil as contained in Condition 17 of 2/13/03 Permit, as amended in 1/30/06) is more stringent than the one in Subpart GG. Therefore, the limit from the PSD permit has been included in the operating permit.

§60.333: Standard for sulfur dioxide:

$SO_2 \leq 0.015$ vol % (150 ppmvd) at 15% O_2 OR fuel sulfur content ≤ 0.8 wt%

The fuel sulfur content requirement in the PSD permit (Condition 12 of 02/13/2003 Permit as amended in 01/30/2006 Permit) is more stringent than the one in Subpart GG. Therefore, the limit from the PSD permit has been included in the operating permit.

The three CT/HRSG stacks are subject to 9 VAC 5-50-80, Standard for Visible Emissions. Under that regulation, each CT/HRSG may not emit visible emissions greater than 20% except for one six-minute period where visible emissions may not exceed 30%. The PSD permit limits the visible emissions from these three CT/HRSG stacks to 10%. Compliance with the permit requirement will ensure that the CT/HRSGs are in compliance with 9 VAC 5-50-80. Therefore, 9 VAC 5-50-80 has been streamlined.

Condition 21 of the PSD permit has been streamlined as described below:

21.a) Per 40 CFR 60.334(b) (NSPS Subpart GG), installation, operation, and maintenance of the water-to-fuel monitoring devices shall not be required if the permittee installs, certifies, maintains, operates, and quality-assures Continuous Emission Monitoring Systems (CEMS) consisting of NO_x and O_2 monitors. This requirement is already included in Condition 25 of the operating permit.

21.b) The operating permit already has requirements more stringent than the sulfur content monitoring requirements of the gaseous fuel combusted in the turbines as contained in 40 CFR 60.334(h) (3) (NSPS Subpart GG). Condition 10 requires that natural gas to be combusted in the turbines shall not exceed a maximum sulfur content of 0.6 grains per 100 dscf. Condition 32 requires the facility to keep fuel analysis records or supplier certifications sufficient to demonstrate the maximum sulfur content limit.

21.c) Per 40 CFR 60.334(h)(2) (NSPS Subpart GG), the permittee shall monitor the nitrogen content of the fuel combusted in the turbines, if it claims an allowance for fuel bound nitrogen. Since Tenaska has not claimed an allowance for fuel bound nitrogen, it is not required to monitor the nitrogen content of the fuel.

Condition 22 of the PSD permit has not been included because all applicable requirements from 40 CFR Part 60, Subpart Da have been incorporated into the operating permit.

Condition 23 of the PSD permit has not been included because all applicable exceptions have already been incorporated in the operating permit.

Condition 25 of the PSD has been streamlined as follows:

Per 60.49 Da, Paragraph (o), the owner or operator of a duct burner, as described in 60.41Da, which is subject to the NO_x standards of §60.44Da(a)(1), (d)(1), or (e)(1) is not required to install or operate a continuous emissions monitoring system to measure NO_x emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere. Since the duct burners associated with the CTs are subject to the NO_x standards of §60.44Da (d)(1), the facility is not required to install or operate a continuous emissions monitoring system to measure NO_x emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere. Since an alternative method of determining SO_2 emissions has been approved (the use of fuel monitoring and sulfur sampling and analysis procedures that comply with the requirements of 40 CFR Part 75, Appendix D), a CEMS for SO_2 is not required.

Facility Wide Conditions

Limitations

The following limitations are applicable requirements from the PSD permit dated 02/13/2003, as amended 01/30/2006. Please note that the condition numbers are from the permit dated 02/13/2003, as amended 01/30/2006; a copy of the permit is enclosed as Attachment B.

Condition 34: Violation of Ambient Air Quality Standards.

Condition 35: Maintenance/Operating Procedures.

Notifications and Recordkeeping

The notifications and recordkeeping requirements in Conditions 32 and 35 of the PSD permit dated 02/13/2003, as amended 01/30/2006; have been included in the operating permit.

Streamlined Requirements

The remaining general conditions (other than Conditions 32, 34 and 35 as described above) in the PSD permit have been modified to meet the general condition requirements of 40 CFR Part 70 and 9 VAC 5-80-110.

GENERAL CONDITIONS

The permit contains general conditions required by 40 CFR Part 72 and 9 VAC 5-80-490 that apply to all Acid Rain operating permit sources. These include requirements for submitting Title V semi-annual monitoring reports and a Title V annual compliance certification report. The permit also requires notification of deviations from permit requirements or any excess emissions, including those caused by upsets, within one business day.

TITLE IV (PHASE II ACID RAIN) PERMIT ALLOWANCES AND REQUIREMENTS

In accordance with the Air Pollution Control Law of Virginia §10.1-1308 and §10.1-1322, the Environmental Protection Agency (EPA) Final Full Approval of the Operating Permits Program (Titles IV and V) published in the Federal Register December 4, 2001, Volume 66, Number 233, Rules and Regulations, Pages 62961-62967 and effective November 30, 2001, and Title 40, the Code of Federal Regulations §§72.1 through 76.16, the Commonwealth of Virginia Department of Environmental Quality issues Phase II Acid Rain permits pursuant to 9 VAC 5 Chapter 80, Article 3 of the Virginia Regulations for the Control and Abatement of Air Pollution (Article 3 Federal Operating Permit (FOP)).

The facility's current Article 3 FOP (which includes the facility's Title V federal operating permit provisions) expires December 31, 2012. The application for renewal of Article 3 FOP was received June 25, 2012. Upon renewal, the Article 3 FOP will have an expiration date of December 31, 2017.

NO_X BUDGET TRADING PROGRAM REQUIREMENTS

The NOx Budget Trading Program (9 VAC 5-140-10) has been replaced by the Clean Air Interstate Rule (CAIR) (9 VAC 5-140-1010 *et seq.*). The requirements related to the NOx Budget Trading Program (Section IX of the current permit) have been removed from the renewal permit. CAIR requirements are included in the renewal permit.

STATE ONLY APPLICABLE REQUIREMENTS

None identified by the applicant.

FUTURE APPLICABLE REQUIREMENTS

None identified by the applicant.

INAPPLICABLE REQUIREMENTS

DEQ reviewed the applicability of the following regulations and determined them to be inapplicable to Tenaska, for the reasons noted.

- *40 CFR Part 60, Subpart D – Standards of Performance for Fossil Fuel-Fired Generators:* The three HRSGs at the facility are subject to Subpart Da. Units regulated under Subpart Da are not subject to Subpart D. Therefore, no emission units at the facility are subject to NSPS Subpart D.

- *40 CFR Part 60, Subpart Db – New Source Performance Standards (NSPS) for Industrial-Commercial-Institutional Steam Generating Units:* The three HRSGs at the facility are subject to Subpart Da. Units regulated under Subpart Da are not subject to Subpart Db.

- *40 CFR Part 60, Subpart Dc – NSPS for Industrial-Commercial-Institutional Steam Generating Units:* The three HRSGs at the facility are subject to Subpart Da. Units regulated under Subpart Da are not subject to Subpart Dc.

- *40 CFR Part 60, Subpart Kb (NSPS for Volatile Organic Liquid Storage Vessels):* The vapor pressure of the liquid stored in the distillate fuel storage tank at the facility is less than 3.5 kPa, which is below the applicability threshold. As a result, 40 CFR 60 Subpart Kb does not apply.

- *40 CFR Part 60, Subpart IIII (NSPS for Stationary Compression Ignition Internal Combustion Engines):* Subpart IIII is subject to engines constructed beginning in 2005. Tenaska's fire water engine was constructed in 2003.

- *40 CFR Part 63, Subpart Q (National Emissions Standards for Hazardous Air Pollutants (NESHAPs) for Industrial Cooling Towers):* This standard does not apply as this facility is not a major source of hazardous air pollutants (HAPs).

- *40 CFR 63 Subpart YYYY (NESHAPs for Stationary Combustion Turbines):* Subpart YYYY is not an applicable requirement for the Tenaska Virginia Generating Station. This standard applies to existing combustion turbines located at a major source of hazardous air pollutants (HAPs). This facility is not a major source of HAP emissions.

- *40 CFR 63 Subpart DDDDD (NESHAPs for Industrial, Commercial, and Institutional Boilers and Process Heaters):* Subpart DDDDD is not an applicable requirement for the Tenaska Virginia Generating Station. The three HRSGs at the facility are not subject to this standard. No fuel burning equipment operated at the facility is subject to this standard as this facility is not a major source of HAPs.

- *40 CFR 63 Subpart UUUUU (NESHAP for Coal- or Oil-Fired Electric Utility Steam Generating Units):* The HRSGs use only natural gas, so Subpart UUUUU does not apply.

GREENHOUSE GASES

Tenaska's potential greenhouse gas (GHG) emissions exceed the thresholds at which GHG are considered a "major NSR pollutant" (100,000 tpy CO_2e and 100 tpy GHG on a mass basis) according to Step 2 of EPA's GHG Tailoring Rule (incorporated into Virginia's State Implementation Plan May 13, 2011). Tenaska has not reported a modification that resulted in a GHG emissions increase since January 2, 2011 (the applicability date of GHG PSD applicability). Tenaska is subject to Title V permitting requirements regardless of GHG emissions due to its potential emissions of criteria pollutants, so there are no additional requirements associated with GHG applicable to Tenaska. GHG calculations are appended (Attachment D).

COMPLIANCE PLAN

In its application for permit renewal, Tenaska has certified that it is currently in compliance with all applicable requirements. No compliance plan was included in the application or in the permit.

INSIGNIFICANT EMISSION UNITS

The insignificant emission units are presumed to be in compliance with all requirements of the Clean Air Act as may apply. Based on this presumption, no monitoring, recordkeeping or reporting shall be required for these emission units in accordance with 9 VAC 5-80-490. Insignificant emission units include the following:

Table 4. Insignificant emission units

Emission Unit No.	Emission Unit Description	Citation	Pollutant(s) Emitted (9 VAC 5-80-720 B)	Rated Capacity (9 VAC 5-80-720 C)
-	500 Gallon Fire Pump Fuel Storage Tank	9 VAC 5-80-720B	VOC	-
-	Three (3) Lube Oil Storage Tanks, 6,200 Gallon Each	9 VAC 5-80-720B	VOC	-
-	4,300 Gallon Lube Oil Storage Tank	9 VAC 5-80-720B	VOC	-
-	18,000 Gallon Anhydrous Ammonia Storage Tank	9 VAC 5-80-720B	NH_3	-
-	45,000 Standard Cubic Feet Hydrogen Storage Tank	9 VAC 5-80-720A	NA	-
-	Numerous Transformers Storing Mineral Oil	9 VAC-5-80-720B	VOC	-
-	Numerous Water and Water Treatment Chemical Storage Tanks	9 VAC-5-80-720A	NA	-

[1]The citation criteria for insignificant activities are as follows:
9 VAC 5-80-720 A - Listed Insignificant Activity, Not Included in Permit Application
9 VAC 5-80-720 B - Insignificant due to emission levels
9 VAC 5-80-720 C - Insignificant due to size or production rate

CONFIDENTIAL INFORMATION

The permittee did not submit a request for confidentiality. All portions of the permit application are suitable for public review.

PUBLIC PARTICIPATION

A public notice regarding the draft permit was placed in the Charlottesville Daily Progress newspaper on October 12, 2012. EPA was sent a copy of the draft permit and notified of the public notice on the same date. All persons on the Title V mailing list were sent a copy of the public notice by either electronic mail or in letters on October 12, 2012. The 30-day public comment period was from October 13, 2012 through November 11, 2012. No comments were received during the comment period. EPA's 45 day comment period ended on November 26, 2012. In an e-mail dated December 3, 2012, EPA Region III staff indicated that EPA would not provide comments on the proposed permit.

ATTACHMENTS

A – 2012 Emission Inventory

B – PSD Permit (dated 02/13/2003 as amended 01/30/2006)

C- Stack Testing Results

D – Greenhouse Gas Emissions Calculations

ATTACHMENT A

2011 Emission Inventory

Commonwealth of Virginia
Department of Environmental Quality

Registration Number: 40995

County - Plant ID: 065-00021

Plant Name: Tenaska Virginia Partners, L.P.

POLLUTANT EMISSIONS REPORT (PLANT) (Tons/Year)

Parameter List

Pollutant Type: All Pollutants

Years: 2011-2011

	CO	NH3	NO2	PB	PM 10	PM 2.5	SO2	VOC
2011	24.407	6.928	119.960	0.001	51.836	51.836	9.975	9.018

ATTACHMENT B

PSD Permit
(dated 02/13/2003 as amended 01/30/2006)

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT

STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE
This permit includes designated equipment subject to
New Source Performance Standards (NSPS).

This permit replaces your permit dated February 13, 2003.

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

Tenaska Virginia Partners, L.P.
1044 North 115th Street, Suite 400
Omaha, NE 68154
Registration No.: 40995
Plant ID No.: 51-065-0021

is authorized to construct and operate

an electrical power generation facility

located at

1.0 mile southeast of intersection of Rte. 619 and Rte. 680
in Fluvanna County, Virginia

in accordance with the Conditions of this permit.

Approved on February 13, 2003

Amendment date January 30, 2006

Larry M Simmons
for, Director, Department of Environmental Quality

Permit consists of 13 pages.
Permit Conditions 1 to 39.
Attachments: Appendix A, Definitions.
Source Testing Report Format.
NSPS Subparts Da and GG.

PERMIT CONDITIONS - the regulatory reference or authority for each condition is listed in parentheses ( ) after each condition.

APPLICATION

1. Except as specified in this permit, the permitted facility is to be constructed and operated as represented in the permit applications dated September 29, 2000, October 25, 2002 and August 30, 2005, including amendment information dated December 11, 2000, July 18, 2001, July 27, 2001 and December 9, 2005. Any changes in the permit application specifications which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action.
(9 VAC 5-50-390, 9 VAC 5-80-1210 D, and 9 VAC 5-80-1720)

PROCESS REQUIREMENTS

2. **Equipment List** - Equipment constructed at this facility consists of:

   - three (3) General Electric (GE) 7FA dual fuel combustion turbines (CTs), each with a nominal winter rating of 183 MW_e and 1,858 million Btu per hour heat input when firing natural gas and 194 MW_e and 2,020 million Btu per hour heat input when firing distillate fuel oil (subject to NSPS Subpart GG);

   - three (3) heat recovery steam generators (HRSG) with supplementary firing duct burners, each duct burner with a design rating of 550 million Btu per hour heat input firing on natural gas. Duct burners shall operate only when the CTs are firing natural gas. (subject to NSPS Subpart Da);

   - one (1) 395 MW_e tandem compound, reheat, condensing steam turbine, receiving steam from the three HRSGs;

   - one (1) 2.1 million gallon, aboveground, distillate fuel oil storage tank;

   - one (1) 14 cell cooling tower, non-chromium based water treatment;

   - one (1) diesel engine driven fire suppression water pump to be used in case of an emergency.

   (9 VAC 5-80-1100 and 9 VAC 5-80-1700 A)

3. **Emission Controls** – Nitrogen oxides (NO_x) emissions from each CT and HRSG duct burner shall be controlled by "dry/low-NO_x" lean premix burners when firing natural gas and water injection when firing distillate fuel oil. The NO_x in the exhaust of the CTs, downstream of the duct burners, shall be controlled by selective catalytic reduction (SCR) with ammonia injection. The CTs, HRSGs and SCR equipment shall be provided with adequate access for

inspection. The SCR equipment shall be in operation when the turbines are in normal operating mode (at all times except during startup and shutdown, as defined in Appendix A). (9 VAC 5-80-1180, 9 VAC 5-50-260 and 9 VAC 5-80-1800 B)

4. **Emission Controls** – Sulfur dioxide (SO_2) emissions from each CT, HRSG duct burner and the fire suppression water pump shall be controlled by the use of low sulfur fuels (pipeline quality natural gas and low sulfur distillate).
(9 VAC 5-80-1180, 9 VAC 5-50-260 and 9 VAC 5-80-1800 B)

5. **Emission Controls** – Sulfuric Acid Mist (H_2SO_4) emissions from each CT and HRSG duct burner shall be controlled by the use of low sulfur fuels (pipeline quality natural gas and low sulfur distillate).
(9 VAC 5-80-1180, 9 VAC 5-50-260 and 9 VAC 5-80-1800 B)

6. **Emission Controls** – Particulate Matter (PM) from the cooling tower shall be controlled by the use of drift eliminators.
(9 VAC 5-80-1180, 9 VAC 5-50-260 and 9 VAC 5-80-1800 B)

7. **Monitoring Devices** –The GE 7FA CTs shall be designed to accommodate devices to continuously monitor and record the fuel consumption and the ratio of water-to-fuel being fired in the turbine when being fired with distillate fuel oil. These systems shall be accurate to within ±5.0 percent. Each monitoring device shall be maintained, calibrated and operated in accordance with approved procedures which shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the GE 7FA CTs are operating. Installation, operation, and maintenance of the water-to-fuel monitoring devices shall only be required if the waiver for monitoring water-to-fuel ratio in Condition 21 is revoked or if the alternate monitoring plan is not approved in writing by both the Valley Regional Office (VRO) Air Compliance Manager and EPA Region III.
(9 VAC 5-80-1180, 9 VAC 5-50-20 C, 9 VAC 5-50-410 and 40 CFR Part 60, Subpart GG)

<u>OPERATING/EMISSION LIMITATIONS</u>

8. **Fuel Throughput** - Each GE 7FA CT can be fired on distillate fuel oil only during the 6 month period of October through March. Each GE 7FA CT shall consume no more than 10.49×10^6 gallons of distillate fuel oil per year, calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-80-1180 and 9 VAC 5-80-1810)

9. **Fuel Throughput** - Each GE 7FA CT shall consume no more than $15,768 \times 10^6$ scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-80-1180 and 9 VAC 5-80-1810)

10. **Fuel Throughput** - Each duct burner shall consume no more than 4,643 x 10^6 scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period and shall operate only when the turbines are firing natural gas.
(9 VAC 5-80-1180 and 9 VAC 5-80-1810)

11. **Fuel Throughput** – The diesel emergency fire suppression water pump shall consume no more than 5,000 gallons of distillate fuel oil per year, calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-80-1180 and 9 VAC 5-80-1810)

12. **Fuel** - The approved fuels for the GE 7FA CTs are natural gas with a maximum sulfur content of 0.6 grains per 100 dry standard cubic feet (as defined in Appendix A) and distillate fuel oil with a maximum sulfur content of 0.01 percent by weight. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-80-1800 and 9 VAC 5-80-1810)

13. **Fuel** - The approved fuel for the duct burners is natural gas with a maximum sulfur content of 0.6 grains per 100 dry standard cubic feet (as defined in Appendix A). A change in the fuel may require a permit to modify and operate.
(9 VAC 5-80-1800 and 9 VAC 5-80-1810)

14. **Fuel** - The approved fuel for the diesel emergency fire suppression water pump is distillate fuel oil with a maximum sulfur content of 0.05 percent by weight. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-80-1800 and 9 VAC 5-80-1810)

15. **Fuel Certification** - The permittee shall perform fuel sulfur monitoring or obtain a certification from the fuel supplier with each shipment of distillate fuel oil as defined in Appendix A to this permit. Each fuel supplier certification shall include the following:

    a. The name of the fuel supplier;

    b. The date on which the distillate fuel oil was received;

    c. The volume of distillate fuel oil delivered in the shipment;

    d. The sulfur content of the distillate fuel oil.

    (9 VAC 5-80-1180 and 9 VAC 5-170-160)

16. **Storage** – The 2.1 million gallon, aboveground storage tank shall store only distillate fuel oil or other petroleum-based liquids that have a true vapor pressure less than 3.5 kPa. Storage of non-pollutant emitting substances may be allowed if approved by the VRO Air Compliance Manager.
(9 VAC 5-80-1180 and 9 VAC 5-50-410)

17. **Emission Limits - Combustion Turbines and Duct Burners -** Stack Emissions from the operation of each GE 7FA CT and associated duct burner shall not exceed the limits specified below except during startup, shutdown, malfunction or fuel transfer:

	Short term limits Duct Burners off; Firing Gas (each unit)	Short term limits Duct Burners on; Firing Gas (each unit)	Short term limits Duct Burners off; Firing Oil (each unit)	Annual limit (tons) (each unit)
PM_{10} (includes condensible PM)	9.7 lb/hr	16.2 lb/hr	21.8 lb/hr	72.92
Sulfur Dioxide	3.1 lb/hr 0.3 ppmvd	4.0 lb/hr 0.3 ppmvd	20.8 lb/hr 1.9 ppmvd	23.59
Nitrogen Oxides (as NO_2)	20.7 lb/hr 3.0 ppmvd	26.7 lb/hr 3.0 ppmvd	48.0 lb/hr 6.0 ppmvd	124.6
Carbon Monoxide	51 lb/hr 12.9 ppmvd	109.5 lb/hr 20.8 ppmvd	69 lb/hr 15.6 ppmvd	350.3
Volatile Organic Compounds	1.7 ppmvd	15.5 ppmvd	2.9 ppmvd	114.32
Sulfuric Acid Mist (H_2SO_4)	0.7 lb/hr	1.7 lb/hr	4.8 lb/hr	8.7

ppmvd ≡ parts per million by volume on a dry gas basis, corrected to 15 percent O_2.

Short term emission limits represent averages for a three-hour sampling period, and apply at all times except during startup, shutdown, malfunction or fuel transfer. Periods considered startup, shutdown and fuel transfer are defined in Appendix A to this permit.

Annual emission limits are derived from the estimated overall emission contribution from operating limits, including periods of startup, shutdown and fuel transfer. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits.
(9 VAC 5-80-1180, 9 VAC 5-50-260, 9 VAC 5-80-1800 and 9 VAC 5-80-1810)

18. **Emission Limits – Duct Burners** – For each stack servicing a GE 7FA CT and associated duct burners, the emissions from the operation of the duct burners shall not exceed the limits specified below except for periods of startup, shutdown, malfunction or fuel transfer:

    0.03 pounds of particulate matter per million Btu heat input

    0.20 pounds of sulfur dioxide per million Btu heat input

    1.6 pounds of nitrogen oxides (as NO_2) per megawatt-hour, gross energy output;

Compliance with the SO_2 and NO_x emission limits of this condition shall be determined on a 30-day rolling average basis. Compliance with the NO_x limits of this condition shall be determined by one of the methods allowed by 40 CFR 60.46a (k) for an affected duct burner used in combined cycle systems or by an alternate method approved by the VRO Air Compliance Manager.
(9 VAC 5-80-1180 and 9 VAC 5-50-410)

19. **Emission Limits** - The following emission limits are for inventory purposes only:

Fire suppression water pump		
Nitrogen Oxides (as NO_2)	7.4 lbs/hr	0.93 tpy

(9 VAC 5-50-260)

20. **Visible Emission Limit - Combustion Turbines** - Visible emissions from the GE 7FA CT/HRSG stacks shall not exceed 10 percent opacity except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown, malfunction and fuel transfer.
(9 VAC 5-50-20, 9 VAC 5-50-260 and 9 VAC 5-50-1810)

21. **Requirements by Reference - Combustion Turbines** - Except where this permit is more restrictive than the applicable requirement, the GE 7FA CTs described in Condition 2 shall be operated in compliance with the requirements of 40 CFR 60, Subpart GG. Exceptions include, but are not limited to:

    a) The permittee need not monitor the water-to-fuel ratio as required at §60.334(a), so long as the NO_x continuous emissions monitoring data availability is no less than 95 percent on a quarterly basis. (This waiver is authorized by the determination memorandum issued by John B. Rasnic, Stationary Source Compliance Div., OAQPS, U.S. EPA, on March 12, 1993, titled "NSPS Subpart GG, Alternative Method." Applicability Determination Index Control Number 9400024)

    b) The daily monitoring of the fuel sulfur content required by §60.334(b) for natural gas may be replaced with procedures from 40 CFR Part 75, Appendix D, if:

        i) the permittee obtains an approved Phase-II Acid Rain permit for each unit;

        ii) the permittee submits a monitoring plan that commits to using pipeline quality natural gas as the primary fuel for the CTs, and this monitoring plan is signed by the designated representative for the units;

iii) the permittee uses one of the options in Section 2.3.1.4 of 40 CFR Part 75, Appendix D to verify that the fuel burned in the CTs qualifies to be classified as pipeline natural gas; and,

iv) only so long as pipeline quality natural gas is the primary fuel.

(This waiver is authorized by the determination issued by Don Watts, Region 4, U.S. EPA, on March 29, 2000, titled "Alternative Testing and Monitoring for Combined Cycle System," Applicability Determination Index Control Number 0000031)

c) The daily monitoring of the fuel nitrogen content (for natural gas only) required by §60.334(b) is waived for natural gas. (This waiver is authorized by the determination issued by Don Watts, Region 4, U.S. EPA, on March 29, 2000, titled "Alternative Testing and Monitoring for Combined Cycle System," Applicability Determination Index Control Number 0000031)

(9 VAC 5-50-400 and 9 VAC 5-50-410)

22. **Requirements by Reference - Duct Burners** - Except where this permit is more restrictive than the applicable requirement, the duct burners described in Condition 2 shall be operated in compliance with the current requirements of 40 CFR 60, Subpart Da.
(9 VAC 5-50-400 and 9 VAC 5-50-410)

23. **Exceptions** – Except as explicitly granted in this permit, exceptions to the requirements by reference, on the basis that the requirements of this permit are more restrictive, are only valid if approved in writing by the VRO Air Compliance Manager or by written authorization from the U.S. EPA Region-III office.
(9 VAC 5-50-400 and 9 VAC 5-170-160)

RECORDS

24. **On Site Records** - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be agreed upon with the Valley Regional Office. These records shall include, but are not limited to:

   a. Annual throughput of distillate fuel oil and natural gas to each GE 7FA CT, calculated monthly as the sum of each consecutive 12-month period.

   b. Annual throughput of natural gas to the duct burners for each GE 7FA CT, calculated monthly as the sum of each consecutive 12-month period

   c. Periods of startup, shutdown, and malfunction of each GE 7FA CT. Periods of startup and shutdown shall be as defined in Appendix A.

d. Periods of fuel transfer for each GE 7FA CT. Periods of fuel transfer shall be as defined in Appendix A.

e. Continuous records of power output for each GE 7FA CT.

f. For each period when a GE 7FA CT fires distillate fuel oil, the date and time when fuel oil firing begins and ends, and other records sufficient to demonstrate that duct burners were not fired for the duration of each such period.

g. Annual throughput of distillate fuel oil to the diesel emergency fire suppression water pump, calculated monthly as the sum of each consecutive 12-month period.

h. Fuel analysis records or supplier certifications sufficient to demonstrate compliance with Conditions 12 through 16.

i. All fuel sampling results and other records required by 40 CFR Part 60, Subparts Da and GG, as they apply to the permitted emission units, unless explicitly waived by other conditions of this permit or by approval from the VRO Air Compliance Manager.

j. Emissions calculations sufficient to verify compliance with the annual emissions limitations in Condition 17, calculated monthly as the sum of each consecutive 12-month period, and records sufficient for calculating actual annual emissions from the remainder of the facility. Emissions shall be calculated using methodology submitted to and approved by the VRO Air Compliance Manager.

k. Continuous monitoring system data, calibrations and calibration checks, percent operating time, and excess emissions.

l. Results of all stack tests, visible emission evaluations and performance evaluations.

m. Log of the observations and maintenance on each GE 7FA CT.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-50-50 and 9 VAC 5-80-330)

CEMS (CONTINUOUS EMISSION MONITORING SYSTEM)

25. **CEMS** - Continuous Emission Monitoring System, meeting the design specifications of 40 CFR Part 75, shall measure and record the emissions of NO_x (measured as NO_2), in ppmvd corrected to 15% O_2, from the combination of each GE 7FA CT and its duct burner. The CEMS shall also measure and record the oxygen content of the flue gas at each location where NO_x emissions are monitored, and measure heat input and power output in accordance with requirements of 40 CFR 60.47.a. A CEMS shall also measure SO_2 to comply with the requirements of 40 CFR Part 75 (acid rain program monitoring), unless an alternative method

of determining SO_2 emissions has been approved for that purpose. Each CEMS shall be calibrated, maintained, audited and operated in accordance with the requirements of 40 CFR 75. For the purposes of this permit, data shall be reduced to 3-hour block averages.
(9 VAC 5-50-40 and 9 VAC 5-80-420)

26. **CEMS Quality Control Program** - A CEMS quality control program, which is equivalent to the requirements of 40 CFR 60.13, and Appendix F shall be implemented for all continuous monitoring systems.
(9 VAC 5-50-40)

27. **Reports for CEMS** - The permittee shall furnish written reports to the VRO Air Compliance Manager of excess emissions from any process monitored by a CEMS on a quarterly basis, postmarked no later than the 30th day following the end of each calendar quarter. These reports shall include, but are not limited to, the following information:

    a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

    b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, malfunctions and fuel transfers, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;

    c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments; and

    d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report.

    (9 VAC 5-50-50)

MINIMUM LOAD PERFORMANCE TESTS

28. **Minimum Load Performance Tests** – The permittee may conduct performance testing for carbon monoxide from each GE 7FA CT to establish a new minimum load as defined in Appendix A. The permittee shall demonstrate compliance with the nitrogen oxides emission limits contained in Condition 17 during the performance testing for carbon monoxide to establish a new minimum load. The minimum load established during this performance test shall replace the current minimum load level of 50%.

    Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the VRO Air Compliance Manager. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the

test results shall be submitted to the VRO Air Compliance Manager within 60 days of test completion.
(9 VAC 5-50-30 and 9 VAC 5-80-1200)

CONTINUING COMPLIANCE DETERMINATION

29. **Visible Emissions Monitoring** - Visual emission observations for each CT/HRSG exhaust stack shall be conducted at least once per week. If visible emissions are observed from any stack, the permittee shall:

    a. Take timely corrective action such that the affected unit resumes normal operation and there are no visible emissions from the exhaust stack, or

    b. Perform a visible emission evaluation (VEE) in accordance with 40 CFR 60, Appendix A, Method 9, to assure visible emissions from the affected unit do not exceed 10 percent opacity. The VEE shall be conducted for a minimum of six minutes. If any of the observations exceed 10 percent, the VEE shall be conducted for a total of 60 minutes. If compliance is not demonstrated by this VEE, timely corrective action shall be taken such that the affected unit resumes operation with visible emissions of 10 percent or less.

    (9 VAC 5-50-20)

30. **Testing/Monitoring Ports** - The permitted facility stacks from the CT/HRSGs shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. (reference 40 CFR Part 60, Appendix A).
    (9 VAC 5-50-30 F)

GENERAL CONDITIONS

31. **Right of Entry** - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

    a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

    b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

    c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

    d. To sample or test at reasonable times.

For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
(9 VAC 5-170-130)

32. **Notification for Control Equipment Maintenance** - The permittee shall furnish notification to the VRO Air Compliance Manager of the intention to shut down or bypass, or both, air pollution control equipment for necessary scheduled maintenance, which results in excess emissions for more than one hour, at least 24 hours prior to the shutdown. The notification shall include, but is not limited to, the following information:

    a. Identification of the air pollution control equipment to be taken out of service, as well as its location, and registration number;

    b. The expected length of time that the air pollution control equipment will be out of service;

    c. The nature and quantity of emissions of air pollutants likely to occur during the shutdown period;

    d. Measures that will be taken to minimize the length of the shutdown or to negate the effect of the outage.

    (9 VAC 5-20-180 B)

33. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the VRO Air Compliance Manager of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone or telegraph. Such notification shall be made as soon as practicable but not later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within 14 days of discovery of the malfunction. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the VRO Air Compliance Manager in writing.
(9 VAC 5-20-180 C)

34. **Violation of Ambient Air Quality Standard** - Regardless of any other provision of this section, the permittee shall, upon request of the board, reduce the level of operation at the facility if the board determines that this is necessary to prevent a violation of any primary ambient air quality standard. Under worst case conditions, the board may order that the permittee shut down the facility, if there is no other method of operation to avoid a violation of the primary ambient air quality standard. The board reserves the right to prescribe the method of determining if a facility will cause such a violation. In such cases, the facility

shall not be returned to operation until it and the associated air pollution control equipment are able to operate without violation of any primary ambient air quality standard.
(9 VAC 5-20-180 I)

35. **Maintenance/Operating Procedures** - The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment, monitoring devices, and process equipment which affect such emissions:

    a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

    b. Maintain an inventory of spare parts.

    c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.

    d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

    Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.
    (9 VAC 5-50-20 E)

36. **Permit Suspension/Revocation** - This permit may be suspended or revoked if the permittee:

    a. Knowingly makes material misstatements in the application for this permit or any amendments to it;

    b. Fails to comply with the conditions of this permit;

    c. Fails to comply with any emission standards applicable to the equipment listed in Condition 2;

    d. Causes emissions from this facility which result in violations of, or interferes with the attainment and maintenance of, any ambient air quality standard;

    e. Fails to operate this facility in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan in effect on the date that the application for this permit is submitted;

    f. Fails to construct or operate this facility in accordance with the application for this permit or any amendments to it; or

g. Allows the permit to become invalid.

(9 VAC 5-80-1210)

37. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the VRO Air Compliance Manager of the change of ownership within 30 days of the transfer.
(9 VAC 5-80-1240)

38. **Registration/Update** - Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact. The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.2-3700 through 2.2-3714 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9 VAC 5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.
(9 VAC 5-170-60 and 9 VAC 5-20-160)

39. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9 VAC 5-80-1180)

Appendix A

Definitions

Startup

- Startup of any GE 7FA CT is defined as operation at loads between zero and the minimum load, not to exceed 5 hours, if the CT was not operated within the previous 8 hours (cold/warm starts) or not to exceed 2 hours if the CT was operated within the previous 8 hours.

Shutdown

- Shutdown is defined as the period of operation, normally 45 minutes, from when a turbine in continuous operation ramps down in power from the minimum load until the unit is no longer being fired or producing emissions.

Minimum Load

- Minimum load is defined as the lowest operating load, established during a performance test, at which CT emission rates are in compliance with permitted emission limits.

Fuel Transfer

Fuel transfer is defined as the period that begins when the turbine(s) work load is reduced below the minimum load for the purpose of transferring to natural gas and ends when distillate fuel oil usage ceases (or vice versa) and the turbine is re-stabilized in a normal work load for the Dry Low NO_x burners. This period is permitted, provided:

(1) Air pollution control practices for minimizing emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two 1-hour averaging periods for any given fuel transfer event unless specifically authorized by DEQ for longer duration.

(2) The permittee shall provide a general description to the Valley Regional Office (VRO) of the procedures to be followed during periods of fuel transfer to ensure that the best operational practices to minimize emissions will be adhered to and the duration of excess emissions will be minimized. The description may be updated as needed by submitting such update to the VRO within 30 days of implementation.

Standard Conditions

- A standard cubic foot of gas is defined as a cubic foot of gas at standard conditions as specified in 40 CFR 72.2 (68°F and 29.92 in Hg).

Fuel Shipment Sampling

For the purpose of applying Condition 15 of this permit, fuel shipment sampling can be conducted in one of the following three ways:

(1) by sampling the distillate fuel oil at a single refinery tank if:

(a) all the fuel delivered in the same shipment comes from one refinery tank and

(b) the tank is not refilled between the first and last tanker truck loading,

(2) testing each individual tanker truck before the fuel oil is added to the on-site storage tank, or

(3) testing the on-site storage tank following the receipt of every fuel oil shipment that is directly preceded by using fuel oil from the on-site storage tank.

SOURCE TESTING REPORT FORMAT

Cover
1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Tester; name, address and report date

Certification
1. Signed by team leader / certified observer (include certification date)
* 2. Signed by reviewer

Introduction
1. Test purpose
2. Test location, type of process
3. Test dates
* 4. Pollutants tested
5. Test methods used
6. Observers' names (industry and agency)
7. Any other important background information

Summary of Results
1. Pollutant emission results / visible emissions summary
2. Input during test vs. rated capacity
3. Allowable emissions
* 4. Description of collected samples, to include audits when applicable
5. Discussion of errors, both real and apparent

Source Operation
1. Description of process and control devices
2. Process and control equipment flow diagram
3. Process and control equipment data

* Sampling and Analysis Procedures
1. Sampling port location and dimensioned cross section
2. Sampling point description
3. Sampling train description
4. Brief description of sampling procedures with discussion of deviations from standard methods
5. Brief description of analytical procedures with discussion of deviation from standard methods

Appendix
* 1. Process data and emission results example calculations
2. Raw field data
* 3. Laboratory reports
4. Raw production data
* 5. Calibration procedures and results
6. Project participants and titles
7. Related correspondence
8. Standard procedures

* Not applicable to visible emission evaluations.

ATTACHMENT C

Stack Testing Results (summarized)

Facility	Turbine Manufacturer	Turbine Model	Test Group	Unit	Fuel	Test Date	Submitted to VDEQ	Load	Heat Input
Fluvanna	GE	7FA	Air Hygiene	1	Gas	May 2004	7/2/2004	Low	
Fluvanna	GE	7FA	Air Hygiene	1	Gas	May 2004	7/2/2004	Base	
Fluvanna	GE	7FA	Air Hygiene	1	Gas	May 2004	7/2/2004	Base DB	
Fluvanna	GE	7FA	Air Hygiene	1	Oil	October 2004	11/9/2004	Base	
Fluvanna	GE	7FA	Air Hygiene	1	Gas	July 2008-CO Test only	9/12/2008	Low	
Fluvanna	GE	7FA	Air Hygiene	1	Gas	July 2008-CO Test only	9/12/2008	Base	
Fluvanna	GE	7FA	Air Hygiene	2	Gas	May 2004	7/2/2004	Low	
Fluvanna	GE	7FA	Air Hygiene	2	Gas	May 2004	7/2/2004	Base	
Fluvanna	GE	7FA	Air Hygiene	2	Gas	May 2004	7/2/2004	Base DB	
Fluvanna	GE	7FA	Air Hygiene	2	Oil	October 2004	11/9/2004	Base	
Fluvanna	GE	7FA	Air Hygiene	2	Gas	July 2008-CO Test only	9/12/2008	Low	
Fluvanna	GE	7FA	Air Hygiene	2	Gas	July 2008-CO Test only	9/12/2008	Base	
Fluvanna	GE	7FA	Air Hygiene	3	Gas	May 2004	7/2/2004	Low	
Fluvanna	GE	7FA	Air Hygiene	3	Gas	May 2004	7/2/2004	Base	
Fluvanna	GE	7FA	Air Hygiene	3	Gas	May 2004	7/2/2004	Base DB	
Fluvanna	GE	7FA	Air Hygiene	3	Oil	October 2004	11/9/2004	Base	
Fluvanna	GE	7FA	Air Hygiene	3	Gas	July 2008-CO Test only	9/12/2008	Low	
Fluvanna	GE	7FA	Air Hygiene	3	Gas	July 2008-CO Test only	9/12/2008	Base	