**ENGINEERING ANALYSIS**

Source Name: **Virginia Electric and Power Company – Brunswick Plant** Permit No.: **52404-001**

Source Location: **Route 58, Brunswick County, Virginia** Engineer: **AMS**

Date: **March 8, 2013**

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I. Introduction and Background

A. Company Background

The facility, as proposed, will be a new, combined-cycle, natural gas-fired, electrical power generating facility. The facility will be located on a 214-acre parcel just south of Route 58, approximately 1.3 miles northeast of Racume in Brunswick County (UTM coordinates are Zone 18 257806mE 407232mN). The nearest residence is approximately 0.5 miles to the east. The nearest schools are Brunswick Academy and Brunswick High School, approximately 5.5 to 6.5 miles away. The nearest hospital/medical center is over ten miles away in Emporia, as are the nearest senior care facilities. There are no Class I areas within 100 km of the proposed facility (see PSD section).

The area is in attainment for all pollutants. Since the source will be a major source, with emissions over 100 tons/yr of Nitrogen Oxides ($NO_x$), carbon monoxide (CO), volatile organic compounds (VOC), Particulate Matter less than 10 microns ($PM_{10}$), particulate matter less than 2.5 microns ($PM_{2.5}$), and greenhouse gas [GHG or $CO_2$ equivalents ($CO_2$e)] over 100,000 tons/yr, Prevention of Significant Deterioration (PSD) permitting for those pollutants - as well as sulfur dioxide ($SO_2$) and sulfuric acid mist ($H_2SO_4$) emissions - will be triggered. The source will not be major for hazardous air pollutants (HAP), so no MACT will apply, and the source will be subject to the State Toxics Rule (6-5).

Site Suitability:

The facility will be located on a site which is suitable from an air pollution standpoint. The area is rural with a combination of undeveloped and transitional land (tree plantations and farms) with forest and woody wetlands. Additionally, the County of Brunswick has certified that the location and operation of the facility are consistent with all applicable ordinances adopted pursuant to Chapter 22 (§15.2-2200 et seq.) of Title 15.2 of the Code of Virginia (see attached Local Governing Body Certification Form).

The following table shows the distances between the proposed plant site and the closest Class I areas. The Federal Land Managers were given the opportunity to comment on whether they will provide a finding of adverse impact on visibility in these Class I areas as a result of the proposed facility. No adverse impact on visibility was suggested.

| Class I area | Distance from project |
|---|---|
| Shenandoah National Park | 173 km |
| James River Face Wilderness Area | 180 km |
| Dolly Sods Wilderness Area | 290 km |
| Swanquarter National Wildlife Refuge | 187 km |

In accordance with Section 10.1-1307 E of the Air Pollution Control Law of Virginia, consideration has been given to the following facts and circumstances relevant to the reasonableness of the activity involved:

1. The character and degree of injury to, or interference with safety, health, or the reasonable use of property which is caused or threatened to be caused:

   The activities regulated in this permit have been evaluated consistent with 9 VAC 5-50-280 (Best Available Control Technology) and 9 VAC 5-60-320 (Toxics Rule) and have been determined to meet these standards where applicable. Please see Section III.C for a description of the Best Available Control Technology included in the permit. Please refer to Section III.B for more information on the applicability of the Toxics Rule to the proposed facility.

   As a fossil fuel-fired steam electric generating plant having heat input greater than 250 million British thermal units (MMBtu) per hour, the proposed facility is a major stationary source according to 9 VAC 5-80-1615 C. In accordance with PSD regulations, air quality modeling was conducted to predict the maximum ambient impacts of criteria pollutants emitted by the proposed source. Even though the source is not within 100 km of a Class I area (an area such as a national park or wildlife sanctuary), an analysis was done to determine compliance with PSD Class I PSD increment for $SO_2$, $PM_{10}$, $PM_{2.5}$, and $NO_2$. The maximum predicted concentrations of those pollutants were well below the Class I significant impact levels (SILs) so no addition air quality analysis was required for Class I area impact.

   For the Class II (all other areas not designated as Class I areas) modeling analysis, predicted impacts from CO (1-hour and 8-hour averaging periods) and $SO_2$ (1-hour, 3-hour, 24-hour, and annual) were below applicable modeling significant impact levels (SILs). No further analyses were required for these pollutants at the indicated averaging periods. However, modeled concentrations for $NO_2$ (1-hour and annual averaging periods), $PM_{10}$ (24-hour averaging period), and $PM_{2.5}$ (24-hour and annual averaging periods) exceeded the applicable SILs. Therefore, a cumulative impact analysis for these pollutants and averaging periods was necessary. The predicted impacts for $NO_2$, $PM_{10}$, and $PM_{2.5}$ from the cumulative impact analysis were less than the applicable National Ambient Air Quality Standards (NAAQS). Hence, the proposed project does not cause or significantly contribute to a predicted violation of any applicable NAAQS or Class II area PSD increment.

   Results of modeling conducted for emissions from the proposed facility show compliance with the health-based NAAQS for all pollutants. Furthermore, single source and cumulative modeling analyses indicate that the proposed project will not result in a violation of any PSD increment. Accordingly, approval of the proposed permit is not expected to cause injury to or interference with safety, health, or reasonable use of property.

   The emissions of toxic pollutants from electric generating units such as those proposed by Dominion are subject to the standards in 9 VAC 5-60-300 et seq. Dominion calculated the emissions of toxic pollutants from all of the emission units proposed for the site. Dominion modeled emissions of toxic pollutants for which proposed emissions exceeded the thresholds in 9 VAC 5-60-320 (acrolein, formaldehyde, cadmium, chromium, and nickel), as well as beryllium, lead and mercury. Modeling demonstrated that proposed emissions of these toxics pollutants are well below the associated Significant Ambient Air Concentrations (SAACs).

   A visibility analysis was done to assess the potential for visual plume impacts in Class II areas within 50 km of the projected site and it was determined that the plume would not be visible within the area around the site. The facility is required to use clean-burning fuels and air pollution control equipment, and is limited to opacity not to exceed 10% at the turbine stacks.

   The results of an analysis to determine the impact of facility emissions on vegetation and soils has demonstrated that the maximum predicted concentrations of $SO_2$, $NO_2$, $PM_{10}$ and CO were below the minimum reported levels at which damage or growth effects to vegetation may occur. And, based on the soil types in the vicinity of the proposed facility and the emissions from the facility, no adverse impact on local soils is anticipated.

2. The social and economic value of the activity involved:

   The social and economic value of the facility submitting the application has been evaluated relative to local zoning requirements. The local government official has deemed this activity not inconsistent with local ordinances. The signed Local Government Form is attached.

   The proposed Dominion-Brunswick facility will generate electricity using only clean-burning natural gas. The availability of clean fuel electric generation facilities is necessary if operation of conventional coal-fired power plants is to be reduced or replaced. Construction of clean-burning, efficient generation plants such as the proposed Dominion-Brunswick facility creates the potential for regional $SO_2$ and $NO_x$ reductions resulting from displacement of older, more polluting forms of electricity generation.

   The Brunswick County Board of Supervisors and the Industrial Development Authority support the construction of the facility and anticipate the placement of the facility in this location will be an economic boon to the region in terms of jobs, taxes, and the availability of natural gas that wasn't previously available in the area.

3. The suitability of the activity to the area in which it is located:

   Consistent with the Board's Suitability Policy dated 9/11/87, the activities regulated in this permit are deemed suitable as follows:

   (i) Air Quality characteristics and performance requirements defined by SAPCB regulations: This permit is written consistent with existing applicable regulations. The proposed facility is a source of toxics emissions and has been modeled and shows compliance with the applicable SAACs. The emissions for criteria pollutants associated with this permit have likewise been modeled and have been shown through modeling to not cause or contribute to a violation of the ambient air quality standards or allowable increments within any Class I or Class II areas.

   (ii) The health impact of air quality deterioration which might reasonably be expected to occur during the grace period allowed by the Regulations or the permit conditions to fix malfunctioning air pollution control equipment:

   (iii) Anticipated impact of odor on surrounding communities or violation of the SAPCB Odor Rule: No violation of Odor requirements is anticipated as a result of the proposed project.

4. The scientific and economic practicality of reducing or eliminating the discharge resulting from the activity: The permit contains a requirement to notify the Piedmont Regional Office within four business hours of the discovery of any malfunction of pollution control equipment (Condition 78).

   The state NSR program as well as the PSD and Non-Attainment programs require consideration of levels of control technology that are written into regulation to define the level of scientific and economic practicality for reducing or eliminating emissions. By properly implementing the Regulations through the issuance of the proposed permit, the staff has addressed the scientific and economic practicality of reducing or eliminating emissions associated with this project.

   The permit requires numerous pollution control strategies that will result in reduction of emissions from the combustion turbines and associated equipment. These include technologies such as the use of clean fuels with low sulfur content, good combustion practices, and clean-burning "low-NOx" lean premix burners as well as add-on control (SCR for NOx removal and an Oxidation Catalyst for CO, VOC, and VOC toxic pollutant control). Other measures have been included in the draft permit, such as a requirement to use ultra-low sulfur diesel oil (no more than 0.0015 % by weight) or propane in emergency equipment and to monitor equipment leaks in the circuit breakers. Feasibility of obtaining further emission reductions was reviewed through the rigorous "top-down" Best Available Control Technology (BACT) requirements of PSD review. No additional controls were found to be technically and economically feasible.

B. Proposed Project Summary

The proposed project will be a new, nominal 1400 MW combined-cycle electrical power generating facility utilizing three combustion turbines each with a duct-fired heat recovery steam generator (HRSG) with a common reheat condensing steam turbine generator (3 on 1 configuration). The proposed fuel for the turbines and duct burners is pipeline-quality natural gas. Emissions from the turbines will be controlled by the use of low carbon fuels and high efficiency design (for GHG), clean fuels and good combustion practices (for $PM_{10}$ and $PM_{2.5}$), SCR and ultra low NOx burners (for NOx), and oxidation catalyst (for CO and VOC). A natural gas-fired auxiliary boiler, three fuel gas heaters, an auxiliary equipment cooler, four inlet chillers, an emergency diesel fire water pump, two emergency generators and an oil storage tank are also proposed and will be subject to emission controls. Electrical circuit breakers potentially emit GHG pollutants (expressed as carbon dioxide equivalents, or $CO_2e$) and they will also be covered in the permit.

Table 1 - Expected emissions from the proposed facility are as follows:

| Pollutant | Emissions (tons/yr) |
|---|---|
| $NO_x$ | 343.6 |
| CO | 477.9 |
| $SO_2$ | 51.1 |
| VOC | 314.2 |
| $PM_{10}$ | 218.0 |
| $PM_{2.5}$ | 217.6 |
| $CO_2e$ | 5,341,291.0 |
| Sulfuric acid mist ($H_2SO_4$) | 30.4 |
| Formaldehyde | 5.88 |
| Acrolein | 0.162 |
| Cadmium | 0.049 |
| Chromium | 0.063 |
| Nickel | 0.094 |

Note: Emissions of regulated toxic pollutants other than formaldehyde, acrolein, cadmium, chromium, and nickel are below permitting exemption thresholds and were therefore not included in Table 1.

C. Process and Equipment Description

| **Equipment to be Constructed** | | | |
|---|---|---|---|
| **Ref. No.** | **Equipment Description** | **Rated Capacity** | **Federal Requirements** |
| **Three on one power block with three natural gas-fired combustion turbine generators, each with a duct-fired heat recovery steam generator (HRSG) , providing steam to a common steam turbine generator** | | | |
| T-1M | Mitsubishi M501 GAC combustion turbine generator with HRSG duct burner (natural gas-fired) | 3,442 MMBtu/hr | NSPS Subpart KKKK<br>NOx trading Subparts AAAAA, BBBBB, and CCCCC |

| Equipment to be Constructed | | | |
|---|---|---|---|
| **Ref. No.** | **Equipment Description** | **Rated Capacity** | **Federal Requirements** |
| T-2M | Mitsubishi M501 GAC combustion turbine generator with HRSG duct burner (natural gas-fired) | 3,442 MMBtu/hr | NSPS Subpart KKKK<br>NOx trading Subparts AAAAA, BBBBB, and CCCCC |
| T-3M | Mitsubishi M501 GAC combustion turbine generator with HRSG duct burner (natural gas-fired) | 3,442 MMBtu/hr | NSPS Subpart KKKK<br>NOx trading Subparts AAAAA, BBBBB, and CCCCC |
| **Ancillary Equipment** | | | |
| B-1 | Auxiliary Boiler (natural gas-fired) | 66.7 MMBtu/hr | NSPS Subpart Dc |
| GH-1, 2, 3 | Three Fuel Gas Heaters (natural gas-fired) | 8 MMBtu/hr each | None |
| EG-1 | Emergency Generator (diesel) | 2200 kW | NSPS Subpart IIII (non-delegated)<br>MACT Subpart ZZZZ (non-delegated) |
| EG-2 | Emergency Generator (propane) | 80 kW | NSPS Subpart JJJJ (non-delegated)<br>MACT Subpart ZZZZ (non-delegated) |
| FWP-1 | Fire Water Pump (diesel) | 305 bhp | NSPS Subpart IIII (non-delegated)<br>MACT Subpart ZZZZ (non-delegated) |
| AEC-1 | Delugeable Auxiliary Equipment Cooler | 69,600 gallons of water/hr | None |
| IC-1, 2, 3, 4 | Four Turbine Inlet Air Chillers (mechanical draft cooling towers) | 690,000 gallons of water/hr each | None |
| CB-1 | Eleven Electrical Circuit Breakers | 18,095 lb $SF_6$ | None |
| ST-1 | Distillate fuel oil tank | 6000 gallons | None |

**Combustion Turbine Generators with duct-fired Heat Recovery Steam Generators (T-1M, T-2M, and T-3M)**

Combustion Turbines (CT)
The source has proposed the installation of three Mitsubishi M501 GAC class CTs in combined-cycle mode.

The gas turbine is the main component of a combined-cycle power system. First, air is filtered, cooled and compressed in a multiple stage axial flow compressor. Compressed air and fuel are mixed and combusted in the turbine combustion chamber. Lean pre-mix dry low-$NO_x$ combustors minimize $NO_x$ formation during natural gas combustion. Hot exhaust gases from the combustion chamber are expanded through a multi-stage power turbine that results in energy to drive both the air compressor and electric power generator.

The CTs are designed to operate in the dry low-NOx mode at loads from approximately 50 percent up to 100 percent rating. Operation at lower loads will only occur during start up and shutdown. The CTs will be periodically taken out of service for scheduled maintenance, or as dictated by economic or electrical demand conditions.

Heat Recovery Steam Generators (HRSG) with Duct Burners (DB)

The proposed facility will use three HRSGs, one for each CT, which will use waste heat to produce additional electricity. Each HRSG will act as a heat exchanger to derive heat energy from the CT exhaust gas to produce steam that will be used to drive a Steam Turbine generator (ST). Exhaust gas entering the HRSG at approximately 1,100°F will be cooled to 180°F by the time it leaves the HRSG exhaust stack. Steam production in the HRSGs will be augmented using duct burners (DBs) that will be fired by natural gas. The proposed DBs will have a firing rate of 501 MMBtu/hr each. The heat recovered is used in the combined-cycle plant for additional steam generation and natural gas/feedwater heating. Each HRSG will include high-pressure superheaters, a high-pressure evaporator, high-pressure economizers, reheat sections (to reheat partially expanded steam), an intermediate-pressure superheater, an intermediate-pressure evaporator, an intermediate-pressure economizer, a low-pressure superheater, a low-pressure evaporator, and a low-pressure economizer. The dry condenser will condense the steam exhausting from the ST. As the steam is condensed, the condensate flows to the condensate receiver tank. Control devices such as selective catalytic reduction (SCR) will be installed, to control $NO_x$ emissions, and oxidation catalysts will be installed to control CO and VOC emissions.

Steam Turbine (ST)

The proposed project includes one reheat, condensing steam turbine generator designed for variable pressure operation. The high-pressure portion of the steam turbine generator receives high-pressure superheated steam from the HRSGs, and exhausts to the reheat section of the HRSGs. The steam from the reheat section for the HRSGs is supplied to the intermediate-pressure section of the turbine, which expands to the low-pressure section. The low-pressure steam turbine generator also receives excess low-pressure superheated steam from the HRSGs and exhausts to the air-cooled condenser. The steam turbine generator set is designed to produce up to approximately 610 MW of electrical output at ISO conditions with duct firing. No pollutants are emitted from the steam turbine.

**Ancillary Equipment**

Turbine Inlet Air Chillers (IC-1 through IC-4)

Four mechanical draft cooling towers will be incorporated to provide air inlet chilling for the CTs. These devices will cool the inlet area during periods of high ambient temperature in order to increase power output and improve efficiency. Particulate matter emissions from the cooling towers associated with the inlet air chillers will be controlled by high efficiency drift eliminators.

Auxiliary Boiler (B-1)

The proposed facility will include a 66.7 MMBtu/hr, natural gas-fired, auxiliary boiler. The auxiliary boiler will provide steam to the ST at start-up and at cold starts to warm up the ST rotor. The steam from the auxiliary boiler will not be used to augment the power generation of the CTs or ST. The boiler is proposed to operate 8760 hrs/yr. NOx emissions from the boiler will be controlled by the use of ultra low NOx burners.

Fuel Gas Heaters (GH-1 through GH-3)

The proposed facility will include three 8.0 MMBtu/hr, natural gas-fired, fuel gas heaters. The heaters will be used to warm up the incoming natural gas fuel to prevent freezing of the gas regulating valves under certain gas system operating conditions. The heaters are proposed to operate 8760 hrs/yr. NOx emissions from the heaters will be controlled by the use of ultra low NOx burners.

Diesel-Fired Emergency Generator (EG-1)

The proposed facility will include a 2200 kW diesel-fired emergency generator that will be operated up to 500 hours per year (including 100 hrs of maintenance checks and readiness testing). The emergency generator will provide power in emergency situations for turning gears, lube oil pumps, auxiliary cooling water pumps and water supply pumps. The emergency diesel generator is not intended to provide sufficient power for a black start, peak shaving or non-emergency power.

Propane-Fired Emergency Generator (EG-2)

The proposed facility will include an 80 kW propane-fired emergency generator that will be operated up to 500 hours per year (including 100 hrs of maintenance checks and readiness testing). The emergency generator will provide power in emergency situations for the uninterruptible power supply for the control house in the switchyard. The emergency propane generator is not intended to provide sufficient power for a black start, peak shaving or non-emergency power.

Diesel-Fired Fire Water Pump (FWP-1)

The proposed project will include a 305 bhp diesel-fired fire water pump operated as a fire water pump driver. The unit will be limited to 500 hours per year, including monthly testing and maintenance (not to exceed 100 hours per year).

Distillate Oil Storage Tank (ST-1)

The proposed project will include a 6,000-gallon, fixed-roof, horizontal, distillate oil storage tank to provide fuel for the emergency generator and fire water pump.

Circuit Breakers (CB-1)

The proposed project will include circuit breakers holding 1,645 lbs of the greenhouse gas sulfur hexafluoride ($SF_6$) per unit. There will be a total of 11 circuit breakers located at the facility, with a total capacity of 18,095 lbs of $SF_6$. Maximum annual leakage rate for $SF_6$ is to be no more than 1%.

Delugeable Auxiliary Equipment Cooler (AEC-1)

Dominion proposes to construct a 12-bay delugeable auxiliary equipment cooler which will cool the lubricating oil for miscellaneous equipment. Forced-draft fans will be incorporated to provide the flow needed for the equipment cooler. The cooler will have four bays equipped with deluge water sprays for additional cooling during extremely hot weather, causing particulate matter emissions from drift.

D. Project Schedule

| | |
|---|---|
| Date permit application received in region | November 29, 2011 (amended March 7, 2012, September 7, 2012, November 5, 2012, and December 21, 2012) |
| Date application was deemed complete | December 21, 2012 |
| Proposed construction commencement date | April 2013 |
| Proposed start-up date | January, 2015 |

II. Emissions Calculations (see attached spreadsheets for detailed emission calculations)

Proposed emissions are primarily products of combustion from the combined cycle units and duct burners. There are also emissions from the auxiliary boiler, fuel gas heater, emergency generators, emergency firewater pump, turbine inlet chillers, auxiliary equipment cooler, and circuit breakers. Permitted emission limits reflect BACT (see section III.C for BACT analysis).

Compliance with the annual emission limits for NOx and CO from the combined cycle units and duct burners will be based on CEMS data. Compliance with the annual $SO_2$ limit will be based on fuel throughput and the sulfur content of the fuel. Compliance with short-term $PM_{10}$, $PM_{2.5}$, and VOC from the combustion units and duct burners will be based on stack testing. Annual emissions will be based on emission factors derived from testing along with fuel throughputs.

Compliance for the annual $CO_2$e emission limits will be on a 12-month rolling total based on CEMS data. Short-term $CO_2$e emissions from the fuel-burning units will not be included in the permit. The turbines will also have a lb/MWh limit and a Btu/kWh heat rate limit to show compliance with the energy-efficiency requirements for GHG BACT.

Emissions from startup and shutdown were considered in the annual permit emissions limits for the combustion turbines, but separate limits will not be included. During startup and shutdown, some post-combustion controls are not working at the optimum level of control, however, during these periods, the turbines and duct burners are also not operating at their highest output and other emissions may be reduced for that reason. Therefore it is important to consider emissions during startup and shutdown in the annual total for emissions. Worst case annual emissions were based on either 8,760 hrs/yr with duct burning, or 7,071 hrs/yr with duct burning plus start up and shutdown (SU/SD) emissions. The facility was not given a limit on the total number of hours of start up and shutdown, but rather the estimated amount of time was factored into the annual emission limits and, therefore, must be complied with by showing compliance with the annual emission limits. BACT applies during startup and shutdown and BACT includes minimization of such SU/SD events.

Emissions from the auxiliary boiler, fuel gas heaters, auxiliary equipment cooler, and inlet chillers were based on 8,760 hrs/yr operation. The emergency generators and fire water pump are permitted to operate no more than 500 hrs/yr.

Emissions from the circuit breakers were based on a maximum annual leakage rate of 1%.

## III. Regulatory Review

The proposed project is a major new source with projected, permitted, annual emissions greater than 100 tons of several criteria pollutants (see Table 1 in Section I.B above).

<u>Greenhouse Gas Emissions Applicability Review:</u>

After July 1, 2011, new sources that have the potential to emit 100,000 tons or more of $CO_2e$ (or 75,000 tons of $CO_2e$ if PSD is triggered by another pollutant) and modified sources with a net emission increase of $CO_2e$ over 75,000 tons year will be required to obtain a PSD permit. The total $CO_2e$ is based on taking the mass emissions of each GHG and multiplying by its Global Warming Potential (GWP). These GWP factors are as follows: $CO_2$: 1; $CH_4$: 21; $N_20$: 310; $SF_6$: 23,900; HFCs: 140 to over 11,700; and PFCs: 5,210 to 9,200. The first three GHG pollutants are primarily from fuel burning and the latter pollutants are from semi-conductor and other production processes. This facility has electrical circuit breakers which contain $SF_6$.

Since the permit for the project will be issued after July 1, 2011 and it will be a PSD source for several other pollutants, and permitted $CO_2e$ emissions will be greater than 75,000 tons, the source would be subject to PSD permitting for GHG (9 VAC 5-85-40).

<u>PSD Permitting</u>: The source is PSD-major for $PM_{10}$, $PM_{2.5}$, $NO_x$, CO, VOC and $CO_2e$ (see Table 2 below). Because one or more pollutants are subject to PSD, the other pollutants at the source ($SO_2$, Lead and $H_2SO_4$) need to be evaluated for PSD at their significance level. $SO_2$ and $H_2SO_4$ exceed the PSD significance level for those pollutants so the facility will be subject to PSD for $SO_2$ and $H_2SO_4$ in addition to the other pollutants mentioned above. The source is required to apply BACT for these pollutants. BACT for these pollutants is discussed in Section III.C.

Table 2- PSD Permitting applicability

| Pollutant | Potential to Emit (TPY) | PSD Major Threshold (TPY)* | Over Major Threshold? | PSD Significance Rate (TPY)** | PSD Required? |
|---|---|---|---|---|---|
| $PM_{10}$ | 218.0 | 100 | **Yes** | 15 | **Yes** |
| $PM_{2.5}$ | 217.6 | 100 | **Yes** | 10 | **Yes** |
| $NO_x$ | 343.6 | 100 | **Yes** | 40 | **Yes** |
| CO | 477.9 | 100 | **Yes** | 100 | **Yes** |
| $SO_2$ | 51.1 | 100 | No | 40 | **Yes** |
| VOC | 314.2 | 100 | **Yes** | 40 | **Yes** |
| $CO_2e$ | 5,341,291.0 | 100,000 | **Yes** | 75,000 | **Yes** |
| Lead | 0.02 | 100 | No | 0.6 | No |
| $H_2SO_4$ | 30.4 | 100 | No | 7 | **Yes** |

*Major Threshold levels from definition of “Major stationary source” in 9 VAC 5-80-1615C

**PSD significance values from definition of “significant” in 9 VAC 5-80-1615C

NSPS Requirements:

Subpart KKKK: The combustion turbines are subject to NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines) which requires the source to meet $NO_x$ and $SO_2$ standards. The source must meet a $NO_x$ limit of 25 ppm when burning natural gas. The source proposes the use of ultra low $NO_x$ burners and SCR to control $NO_x$ emissions. $NO_x$ emissions from the proposed combustion turbines are expected to be around 2.0 ppmvd when burning natural gas which is below the NSPS standard and is considered Best Available Control Technology (BACT). The source will put $NO_x$ CEMS on the turbine stacks to show compliance with the BACT limits.

The source proposes using low-sulfur fuel (natural gas) to control $SO_2$ from the turbines and duct burners. To be in compliance with NSPS KKKK, they must not exceed 0.06 lb $SO_2$/MMBtu from fuel burning. The source has proposed a BACT emission limit of 0.00112 lb $SO_2$/MMBtu. BACT is discussed in more detail in Section III.C. Turbines regulated under NSPS Subpart KKKK are not subject to NSPS Subpart GG, and HRSGs and duct burners regulated under NSPS Subpart KKKK are not subject to NSPS Subparts Da, Db, or Dc.

Subpart Dc: The 66.7 MMBtu/hr auxiliary boiler is subject to NSPS Subpart Dc Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units as a steam-generating unit between 10 and 100 MMBtu/hr. Since it will be burning natural gas only, it will be required to keep records of the amount of fuel burned each calendar month. The three 8 MMBtu/hr fuel gas heaters are not subject to this part.

Subpart IIII*: The emergency diesel fire water pump and diesel emergency generator are subject to NSPS Subpart IIII. The 227.4 kW diesel fire water pump is subject to a $NO_x$ + non-methane hydrocarbon (NMHC) limit of 4.0 g/kW-hr, a PM limit of 0.2 g/kW-hr, a CO limit of 3.5 g/kW-hr, and a requirement to use ULSD with no more than 15 ppm sulfur content. The 2200 kW diesel emergency generator is subject to a $NO_x$ + NMHC limit of 6.4 g/kW-hr, a PM limit of 0.2 g/kW-hr, a CO limit of 3.5 g/kW-hr, and a requirement to use ULSD with no more than 15 ppm sulfur content.

Subpart JJJJ*: The emergency propane-fired generator is subject to NSPS Subpart JJJJ for spark-ignition internal combustion engines, with a requirement to use certified engines and maintain them properly.

*Although the source must be in compliance with the requirements for these emergency units, DEQ has not elected to receive delegation for enforcement of these regulations, so no requirements specific to this regulation will be included in this permit (but will be referenced in the permit cover letter). BACT limits will be used to ensure the NSPS standards are met.

Subpart TTTT (proposed). A new NSPS (Subpart TTTT) could possibly be in place before this source constructs the turbines so the turbines could be subject to that subpart. The proposed standard is a $CO_2$ emission limit of 1,000 lb/MWh (gross annual average considering all operation), although a range has been examined that covers 950-1100 lb/MWh. Expected emissions of $CO_2$ from the facility are around 920 lb/MWh at maximum operating capacity, so it is expected that, on an annual average, the source will be able to meet the proposed 1,000 lb/MW-hr $CO_2$ standard. When the source conducts Part 75 monitoring for Acid Rain, it will fulfill the proposed monitoring requirements for NSPS Subpart TTTT.

MACT Requirements:

Subpart ZZZZ*: The emergency diesel fire water pump and emergency generators are also subject to MACT Subpart ZZZZ (40 CFR 63.6590.c.1) for area sources of HAP. Compliance with this MACT is met by complying with NSPS Subpart IIII or NSPS Subpart JJJJ requirements, as applicable.

*DEQ has not elected to receive delegation to enforce this federal regulation so requirements for this specific regulation will not be included in the permit but will be referenced in the permit cover letter.

Non-applicable Subparts: As an area HAP source, the facility will not be subject to MACT Subpart YYYY for turbines or MACT Subpart Q for cooling towers.

Other:

Cross State Air Pollution Rule (CSAPR)/Clean Air Interstate Rule (CAIR)
On August 21, 2012, the United States Court of Appeals for the D.C. Circuit vacated CSAPR but continued to leave CAIR in place pending EPA's promulgation of a replacement rule that complies with the courts' rulings. Virginia at this time will implement the CSAPR requirements through the federal implementation plan (FIP) as per Chapter 291 of the 2011 Virginia Acts of Assembly and 40 CFR 97.

Title IV/Acid Rain Permit
The source will also be subject to the Acid Rain permit regulations but will seek an Acid Rain permit at a later date. The source will be subject to Article 3 Federal Operating (Title IV) permitting and must submit an application within a year of commencing operation.

**State New Source Review:**

Emissions subject to Major New Source Review (Article 8 – PSD) are not subject to Article 6 New Source Review as per 9 VAC 5-80-1100H. The only pollutant which is not subject to PSD is lead. The total lead emissions from the facility are 0.02 tons/yr. This is below the exemption rate for lead in 9 VAC-5-80-1320C, so emissions of lead will not be subject to Article 6 regulations.

A. Criteria Pollutants

Criteria pollutant modeling was conducted to ensure that the facility will not violate the NAAQS (see section IA above, under site suitability) .

PSD increment
The PSD increment modeling showed that the concentrations for all pollutants and averaging periods were below the applicable PSD increments (see modeling memo attachment).

B. Toxic Pollutants

MACTs have been promulgated for Combustion Turbines that are major sources of HAP (Subpart YYYY National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines) and for cooling towers at major sources of HAP (Subpart Q National Emission Standards for Hazardous Air Pollutants For Industrial Process Cooling Towers). HAP emissions from this facility will be below major levels, so there will be no MACT requirements for the Combustion Turbines or Cooling Towers and, therefore, the State Toxics Rule (Rule 6-5, 9 VAC 5-60-300) will apply. The source will need to demonstrate that they are minor for HAPs.

The only HAPs that exceed the exemption rate in 9 VAC 5-60-300 are acrolein, formaldehyde, cadmium, chromium and nickel. Emission limits for these HAPs will appear in a State Only section of the permit. Modeling has shown that emissions of these HAPs will not exceed the Standard Ambient Air Concentration (SAAC) (see modeling memo attachment).

The emergency diesel fire water pump and emergency generators are subject to MACT Subpart ZZZZ as an area source as per the application submitted by Dominion. The requirements for this unit will be to comply with NSPS Subpart IIII or NSPS Subpart JJJJ requirements, which will be enforced by EPA, not DEQ.

C. Control Technology

Note: Although this plant will be very similar to the electric power plant permitted in Warren County in 2010, emissions are slightly different for the following reasons:

- $PM_{10}$, $PM_{2.5}$, $SO_2$ and $H_2SO_4$ emissions are slightly higher due to the level of sulfur in the natural gas supplied to the Brunswick County area. Warren County natural gas has a sulfur content of 0.1 gr/100 dscf and Brunswick County has a sulfur content of up to 0.4 gr/dscf.

- The Warren County plant is at a higher altitude (almost 600 ft above MSL) than the Brunswick plant (250 ft above MSL). At lower elevations, turbines experience higher air pressure and higher temperatures. The higher temperatures reduce efficiency, while the higher pressure actually boosts power output, so both scenarios have an impact on emissions.

- The Warren County plant is located very near to a Class I area (Shenandoah National Park) and therefore is subject to more restrictive emission standards and tougher modeling protocol. The Brunswick plant is not located within 100 km of a Class I area, and the Federal Land Managers stated that no impact to a Class I area was expected from this project, however an analysis was done to determine compliance with the Class I PSD increment. This analysis showed that the facility emissions would be below the Class I Significant Impact Level for $SO_2$, $PM_{10}$, $PM_{2.5}$ and $NO_2$.

**PSD BACT**: Sources that are subject to PSD permitting, must apply BACT to those pollutants that triggered PSD permitting (see Table 2 in Section III). The determination of BACT usually involves a top-down method:

Step 1 – Identify all possible control technologies;
Step 2 – Eliminate technically infeasible options;
Step 3 – Rank the technically feasible control technologies based upon emission reduction potential;
Step 4 – Evaluate ranked controls based on energy, environmental, and/or economic considerations; and
Step 5 – Select BACT.

PSD procedures require that the BACT cost feasibility analysis be based upon recent permit determinations for similar facilities. Federal guidance is clear that there can be no fixed or "bright line" cost established as representative of BACT. Rather, the cost of reducing emissions, expressed in dollars per ton, is to be compared with the cost incurred by other sources of the same industry type. A listing of BACT determinations from the RACT/BACT/LAER Clearinghouse for similar facilities is included as Appendix C in the Dominion – Brunswick application.

1. Greenhouse gasses: In this case, $CO_2e$ emissions from the proposed facility trigger PSD permitting (on both a mass basis and $CO_2e$ basis, see Table 2 above) so BACT must be determined for $CO_2e$. $CO_2e$ is a relatively new regulated pollutant so there are few determinations in the RACT/BACT/LAER Clearinghouse to compare.

   a. Combustion Turbines

      i. Possible Control Technologies (Step 1):

      - Carbon capture and sequestration/storage: One such technology that is being discussed to control $CO_2$ is Carbon Capture and Sequestration/Storage (CCS). CCS consists of concentrating/capturing $CO_2$ from exhaust and transporting it to a location where it can be stored for a long time, deep in the ground. It is being demonstrated on pilot-scale power plant projects and on other types of facilities around the world.

- Efficient power generation: Another strategy being used to minimize $CO_2$ emissions is to maximize the energy efficiency and performance of the turbines (i.e., minimize the amount of fuel combusted to produce the desired amount of electricity). This has been the most accepted BACT for natural gas, combined-cycle plants. By using more efficient turbines and including the steam system to capture heat from the exhaust, energy efficiency is maximized and $CO_2$ emissions can be minimized.

- Using low carbon fuel, like natural gas instead of coal, can reduce GHG.

- Using renewable energy or alternative energy sources - such as solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, nuclear, geothermal electric, energy from waste, anaerobic digestion, tidal energy, and wave energy - reduces the use of fossil fuels.

ii. Technical feasibility and availability of control technologies (Step 2):

CCS - Although the carbon capture technology is available and technically feasible for some applications (such as natural gas processing industries and petroleum refining), it is not a proven option for a natural gas, combined cycle combustion turbine whose exhaust is characterized by high flow and low $CO_2$ concentration (and certainly not for other fuel combustion sources such as boilers, fuel gas heaters or emergency generators). There are no instances that could be found of CCS being used on such a facility. $CO_2$ transport poses a problem as well. The proposed location does not appear to be geologically ideal for CCS but could offer some marginal options. Areas in southwest Virginia are more promising for this aspect of CCS but a pipeline does not currently exist. $CO_2$ storage in geologic formation underground must be carefully considered as there is some uncertainty as to the impact of such technology on the groundwater. The CCS technology can cause a significant energy penalty (estimated to be up to 15%) which could cause the units to have to burn more fuel and create more air pollution than would otherwise be emitted, and/or reduced power output. CCS works best on larger units, especially coal burning units, which have the potential to emit $CO_2$ in larger concentrations than this plant, and that are located near sequestration areas. The feasibility and availability of CCS for the proposed power facility is marginal, at best.

Efficient power generation is technically feasible and available for this project.

Low carbon fuels are technically feasible and available for this project

Renewable/alternative energy sources – For investor-owned utilities, Virginia has a Renewable Portfolio Standard goal of 15% of base year (2007) sales of alternative energy by the year 2025. And in 2012, legislation was passed to encourage research and development of renewable and alternative energy source (www.dsireusa.org). Virginia also has legislation (Virginia Mandatory Utility Green Power Option) that allows customers the option to purchase 100% renewable energy from a utility. Dominion participates in this program by buying certificates from renewable energy facilities. Although not mandated by regulation, Virginia is trying to establish a market for energy that reduces the carbon emissions from power generation. Brunswick County, however, is not an ideal location for either wind power or solar power generation, nor is it practical for hydro power, tidal power, or wave power. Nuclear power has been demonstrated in Virginia but is not within the scope of this project and would require significant design changes. Geothermal electric production is not viable in Virginia. And, although renewable energy (i.e., biomass) reduces the need for fossil fuels, the combustion of most other sources of carbon does not result in a reduction of $CO_2$ emissions in the short term. (http://www.energy.vt.edu/vept/index.asp). Therefore, DEQ finds that, at this point in time, renewable or alternative energy options are not available or technically feasible on a large scale in Brunswick County and that the use of alternative fuels and nuclear power would be considered redefining the source.

iii. Rank GHG control technologies (Step 3):

Since BACT is based on an emission limitation which reflects the maximum degree of reduction for a particular pollutant, then the best means of comparison is of emission limits rather than % control efficiency. Since energy efficiency plays a role in emissions, one must compare efficiency limits based on output (Btu/kWh or lb/kWh) rather than mass limits based on heat input (lb/MMBtu). This is because, as a unit gets older and less efficient, it may still meet a lb/MMBtu limit while, at the same time, using more fuel to achieve its heat input need, therefore increasing emissions. Only a handful of CCT have been permitted for GHG so a quick comparison can be made. As can be seen in Table 3 below, this project is a bit larger than most of the other, recently permitted or proposed NGCC projects. Keeping in mind that thermal efficiency increases with larger turbines, and the net heat rate (Btu/kWh) decreases, the BACT level proposed for the 1400 MW Brunswick plant and the other permitted or proposed 180-1,000 MW plants is comparable. When comparing a heat rate limit, it is important to know whether it is based on a HHV or LHV and whether it is for a gross power output or a net power output, and duct fired or not duct-fired operation. This is not always evident when researching other facilities. Also, some GHG BACT proposals include a "degradation factor" which takes into consideration the heat rate of a unit as it gets older and less-efficient (see discussion of the proposed BACT in Section 5 of Dominion's application for a detailed list of energy efficient practices that are proposed). More recently permitted plants have considered degradation, while earlier permitted plants may not have.

Table 3 – Comparison of GHG BACT determinations

| **Facility** | **Type** | **GHG BACT limits** | **Basis** |
|---|---|---|---|
| Dominion VA- Brunswick, VA | 1400 MW NGCC | 7500 Btu/kWh (net HHV) and 920 lb/MWh | Thermal Efficiency |
| Cricket Valley Energy Ctr, NY | 1000 MW NGCC | 7605 Btu/kWh (net HHV) and 950 lb/MWh | Thermal Efficiency |
| Hess Newark Energy Center, NJ | 655 MW NGCC | 7522 Btu/kWh (net HHV) w/o DB and 887 lb/MWh (gross) | Thermal Efficiency |
| CPV Valley Energy, NY | 630 MW NGCC | 7605 Btu/kW (LHV) w/o DB and 950 lb/MWh | Thermal Efficiency |
| PacifiCorp Lake Side, UT | 629 MW NGCC | 6918 Btu/kW (HHV) and 950 lb/MWh (gross) | Thermal Efficiency |
| Russell City Energy Ctr, CA | 600 MW NGCC | 7730 Btu/kWh and 242 tons/hr | Thermal Efficiency |
| LCRA Ferguson replacement, TX | 590 MW NGCC | 7720 Btu/kWh (net HHV) and 918 lb/MWh | Thermal Efficiency |
| Sevier Power Company, UT | 580 MW NGCC | 7515 Btu/kWh and 1,958,558 tons/yr | Thermal Efficiency |
| Palmdale Hybrid Power, CA | 570 MW NGCC and 50 MW solar collectors | 7319 Btu/kWh and 774 lb/MWh (source-wide) | Thermal Efficiency |
| Pioneer Valley Energy, MA | 431 MW CC (oil backup) | 6840 Btu/kWh and 895 lb/MWh | Thermal Efficiency |
| Deer Park (Calpine) Energy Center, TX | 180 MW NGCC | 7730 Btu/kWh (net) and 920 lb/MWh | Thermal Efficiency |
| Channel Energy Center, TX | 180 MW NGCC | 7730 Btu/kWh (net) and 920 lb/MWh | Thermal Efficiency |
| Kalama Energy Center, WA | 346 MW NGCC (peaker) | 858 lb/MWh | Thermal Efficiency |

No information could be found on GHG BACT limits for a natural gas combined cycle power plant using CCS for comparison with a thermal efficiency approach but estimates have shown it to be about 90% effective in reducing GHG emissions. One study[1] predicted that a natural gas-fired power plant that had a $CO_2$ emission rate of

1 Rubin, Edward S and Haibo Zhai. The Cost of Carbon Capture and Storage for Natural Gas Combined Cycle Power Plants. *Environ. Sci. Technol.* 46:3076-3084 (2012)

803 lb/MWh could reduce emissions to 94 lb/MWh by adding CCS, but at a cost of $1336/kW.

iv. BACT determination for GHG- most effective controls (Step 4):

Of the technologies mentioned in Step 1 above, construction of a carbon capture control, transport and storage system for $CO_2$ gas in the Brunswick County region would be cost-prohibitive. A recent study suggested that adding CCS technology could increase plant construction costs up to $200 million[2]. Dominion calculated that construction of a pipeline to transport the collected $CO_2$ would be $250 million alone. These factors, and the cost from a 15-20% energy penalty which increases fuel usage, would make CCS economically infeasible at this time (see Section 5 of Dominion's application for a more in-depth analysis).

The remaining technologies, namely efficient power generation and the use of low carbon fuels, are proposed for this facility and are accepted as BACT. Due to differences in size, manufacturer, configuration, cooling practice, elevation, and the method used to determine the heat rate among the permitted power plants across the country, some variability in BACT determinations is expected, however, DEQ determines that the proposed emission level of $CO_2e$ and level of energy efficiency are BACT for this facility. The plant will be required to operate at a higher heating value heat rate of no more than 7,500 Btu/KWh (based on a degradation estimate* for a new 6,695 Btu/kWh unit – HHV/net), and emit $CO_2e$ at an average annual rate not to exceed 920 lb $CO_2e$/MWh (which reflects a 119.12 lb $CO_2$/MMBtu average monitored emission rate at similar facilities adjusted by a 3% margin to account for emissions from SU/SD and low load operation) - both of which fall into the range of BACT of recently issued or drafted GHG PSD permits (see Table 3 above).

*The degradation estimate is based on a 3.4% performance margin of the combustion turbines, a 1.2% degradation margin for the auxiliary power, and a 7.1% degradation margin for the steam turbine system – 6695 x 1.034 x 1.012 x 1.071 = 7500 Btu/kWh net HHV. And 119.2 lb/MMBtu x 7500 Btu/kWh x 1.03 x 1,000 kWh/MW x 1 MMBtu/1,000,000 Btu = 920.2 lb/MWh HHV net.

b. Auxiliary Boiler and Fuel Gas Heaters
CCS for control of the emissions of $CO_2e$ from these smaller fuel-burning units is not technically feasible or available. BACT for these units will be the use of low carbon fuel and energy efficient design and operation.

c. Emergency generators and fire water pump
Add-on $CO_2$ controls are not technically feasible for emergency generators so BACT for the fire pump will be fuel-efficient design and a limit of 500 operating hours/yr.

d. Electrical Breakers
The electrical circuit breakers contain $SF_6$ which is a GHG. There is a small potential for these sealed units to release $SF_6$ from leaks. Although an alternative to the $SF_6$ would be to use oil or air-blast circuit breakers, which would not have the potential to release $SF_6$, this technology is being replaced by the sealed $SF_6$ circuit breakers due to the superior insulating and arc-quenching capabilities of the $SF_6$ type units. The oil and air-blast units are also larger than the $SF_6$ units, generate more noise, and the dielectric oil is flammable and also has adverse environmental impact if released. Studies have shown that the leakage rate for $SF_6$ from these circuit breakers is between 0.2 and 2.5 percent over the lifetime of the unit.[3] Therefore, BACT for the circuit breakers will be to minimize

2 Fishbeck, Paul S, David Gerard, and Sean T McCoy. Sensitivity analysis of the build decision for carbon capture and sequestration projects. *Greenhouse Gas Sci. Technol. 2:36-45* (2012)
3 *$SF_6$ Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source*, J. Blackman (U.S. EPA, Program Manager, SF6 Emission Reduction Partnership for Electric Power Systems), M. Averyt (ICF Consulting), and Z. Taylor (ICF Consulting), June 2006.

$SF_6$ leakage by using an enclosed-pressure circuit breaker with no more than a 1.0 percent annual leakage rate and a leak detection system.

2. $NO_x$ Control

a. Combustion Turbines with duct-fired HRSG

i. Step 1 - Combustion turbines and the associated duct burners generate most of the $NO_x$ emissions from the facility. The following control technologies were identified by Dominion as applicable to $NO_x$ treatment for combined-cycle combustion turbines:

• Selective Catalytic Reduction (SCR)
• SCONOX™
• Selective Non-Catalytic Reduction (SNCR) and Non-Selective Catalytic Reduction (NSCR)
• Dry Low-$NO_x$ (DLN) Combustors
• Water or Steam Injection
• XONON™, LoTOx™, THERMALLONOx™, and Pahlmann™

ii. Step 2 – The technical feasibility and availability of each technology is discussed below:

SCR is a process that involves post combustion removal of $NO_x$ from the flue gas with a catalytic reactor. In the SCR process, ammonia injected into the turbine exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. SCR converts nitrogen oxides to nitrogen and water through several possible reactions that take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the $NO_x$ decomposition reaction. Technical factors related to this technology include increased turbine backpressure, exhaust temperature materials limitations, thermal shock/stress during rapid starts, catalyst masking/blinding, reported catalyst failure due to "crumbling", design of the $NH_3$ injection system, and high $NH_3$ slip. SCR using ammonia as a reagent represents the state-of-the art for back end gas turbine $NO_x$ removal from base load, combined-cycle turbines. SCR is technically feasible and available

SCONOX™ is an emerging post-combustion technology that removes $NO_x$ from the exhaust gas stream after formation in the combustion turbine. SCONOX™ employs a potassium carbonate bed that adsorbs $NO_x$ where it reacts to form potassium nitrates. Periodically, a hydrogen gas stream is passed over the bed, resulting in the reaction of the potassium nitrates to re-form the potassium carbonate and the ejection of nitrogen gas and water.

SCONOX™ is reportedly capable of achieving $NO_x$ emission reductions of 90% or more for combustion turbine application, and it is currently operating on several small natural gas-fired turbines. The most notable advantage of SCONOX™ over SCR is that it reduces $NO_x$ without the use of ammonia. SCONOX™ thereby eliminates the possibility of "ammonia slip", or emissions of excess (unreacted) ammonia, that is present with use of SCR for $NO_x$ control. Similar to SCR, SCONOX™ only operates within a specific temperature range.

SCONOX is no longer being offered for large combustion turbines. SCONOX™ is considerably more complex than SCR, would consume significantly more water, and would require more frequent cleaning and other maintenance. SCONOX is available but not technically feasible for a plant of this size.

The two other back-end catalytic reduction technologies, SNCR and NSCR, have been used to control emissions from certain other combustion process applications. However, both of these technologies have limitations that make them inappropriate for application to combustion turbines. SNCR requires a flue gas exit temperature in the range of 1,300 to 2,100 °F, with an optimum operating temperature zone between 1,600 and 1,900 °F. Simple-cycle combustion turbines have exhaust temperatures of approximately 1,100 °F, and combined-cycle turbines have exhaust temperatures much lower than simple-cycle turbines. Therefore, additional fuel combustion or a similar energy supply would be needed to create exhaust temperatures compatible with SNCR operation. This temperature restriction and related economic considerations make SNCR infeasible and inappropriate for the proposed combustion turbines. NSCR is only effective in controlling fuel-rich reciprocating engine emissions and requires the combustion gas to be nearly depleted of oxygen (<4% by volume) to operate properly. Since combustion turbines operate with high levels of excess oxygen (typically 14 to 16% $O_2$ in the exhaust), NSCR is infeasible and inappropriate for the proposed combustion turbines.

DLN combustion control techniques reduce NOx emissions without injecting water or steam (hence "dry"). DLN combustors are designed to control peak combustion temperature, combustion zone residence time, and combustion zone free oxygen, thereby minimizing thermal NOx formation. This is accomplished by producing a lean, pre-mixed flame that burns at a lower flame temperature and excess oxygen levels than conventional combustors.

DLN combustors have been employed successfully for natural gas-fired combustion turbines for more than fifteen years. DLN combustors are available and technically feasible.

Water or steam injection is also designed to control peak combustion temperature, combustion zone residence time, and combustion zone free oxygen, thereby minimizing thermal NOx formation. This technology involves the injection of water or steam into the high temperature region of the flame, which minimizes thermal $NO_x$ formation by quenching peak flame temperature.

Water and steam injection has been employed successfully for nearly thirty years, for both natural gas and oil-fired combustion turbines. Water and steam injection remains the state-of-the-art combustion technology for minimizing $NO_x$ emissions for oil-fired combustion turbines.

Water injection is considered to be available and technically feasible for combustion turbines for natural gas and oil firing operations but would not be employed with DLN burners.

XONON™, LoTOx™, THERMALLONOx™, and Pahlmann™

A number of other combustion turbine NOx emissions control technologies for combustion turbines are being marketed including XONON™, LoTOx™, THERMALLONOx™, and Pahlmann™. None of these technologies has reached the commercial development stage for large combustion turbines that will be fired with natural gas, and thus none are considered to be technically feasible for application to this project. DEQ concurs that these technologies are not yet commercially available technology suitable for controlling CTs of the size proposed at the Dominion Brunswick site.

iii. Step 3 – Ranking of available $NO_x$ controls

The most effective technologies that are available for a large natural gas-fired, combined cycle power generating facility for controlling $NO_x$ are dry low $NO_x$ combustion to minimize $NO_x$ formation and post-combustion treatment with SCR.

iv. Step 4 - BACT Determination: Selective Catalytic Reduction (SCR) and Dry Low-$NO_x$ (DLN) Combustors

Dominion has proposed a combination of the remaining identified control options for $NO_x$: dry low-$NO_x$ combustion and selective catalytic reduction (SCR). The proposed Mitsubishi M501 GAC turbines use a two-stage premixed combustion design resulting in uncontrolled $NO_x$ emissions of 15 ppmvd at 15% $O_2$ when firing natural gas, the fuel proposed for use by Dominion. The draft permit proposes use of SCR to control $NO_x$ emissions from the CTs to the following level (at 15% $0_2$):

- 2.0 ppmvd with or without duct burning

Compliance with the limits is to be based on a one-hour block average.

From 2007 to 2011, approximately 15 projects were permitted at 2.0 ppmvd at 15% $O_2$, including two LAER determinations. Recent PSD permits at 2.0 ppmvd at 15% $O_2$ include a December 17, 2010 permit for a CCT in Warren County, Virginia, and a September 1, 2011 permit for a Texas Power Plant. There was one project that was permitted at a $NO_x$ emission rate of 1.5 ppmvd at 15% $O_2$ in the year 2000. However, this project has not been built and therefore, 1.5 ppmvd at 15% $O_2$ has not been demonstrated as achievable in practice. With that one exception, the proposed limits are as stringent as any listed in EPA's RACT/BACT/LAER Clearinghouse (RBLC) for electric generating facilities.

b. Auxiliary boiler and Fuel Gas Heaters
   i. List of control technologies
      - Front end $NO_x$ reduction technologies (low excess air, low $NO_x$ burners, ultra low $NO_x$ burners)
      - SCR
   ii. Technical feasibility and availability of $NO_x$ Control
      - All technologies are feasible and available
   iii. Ranking of technologies
      - The best $NO_x$ reduction could be achieved using both front end and add-on $NO_x$ reduction technologies
      - Alternatively, ultra low $NO_x$ burners are the best front end technology for reducing $NO_x$ emissions
   iv. BACT determination
      - The use of SCR in conjunction with ultra low $NO_x$ burners has been determined to be economically infeasible for the auxiliary boiler and fuel gas heaters at costs exceeding $64,000 per ton for the boiler and $289,000 per ton for the fuel gas heaters.
      - DEQ concurs with Dominion that ultra low $NO_x$ burners are BACT for both units

c. Emergency Generators/Fire water pump
Although add-on controls such as SCR are used to control $NO_x$ on larger generators, if necessary to meet national standards for emissions, the proposed emissions from the emergency units at this facility can meet these standards without add-on controls. The facility proposes a $NO_x$ limit for the 80 kW propane emergency generator of 4.3 g/hp-hr based on manufacturer estimates. The facility proposes a limit of $NO_x$+NMHC on the

2200kW diesel emergency generator (EG-1) of 6.4 g/kW-hr on ULSD. And the 305 hp diesel fire water pump (FWP-1) has a proposed $NO_x$+NMHC limit of 4.0 g/kW-hr. This is in compliance with NSPS standards for newer diesel engines of those sizes and is considered BACT for those units.

3. Carbon Monoxide Control - Carbon monoxide emissions are formed in the exhaust of a combustion turbine as a result of incomplete combustion of the fuel. Similar to the generation of $NO_x$ emissions, the primary factors influencing the generation of CO emissions are temperature and residence time within the combustion zone. Variations in fuel carbon content have relatively little effect on overall CO emissions. Generally the effect of the combustion zone temperature and residence time on CO emissions generation is the exact opposite of their effect on $NO_x$ emissions generation. Higher combustion zone temperatures and residence times lead to more complete combustion and lower CO emissions, but higher $NO_x$ emissions.

   a. Combustion Turbines

      i. Possible Control Technologies (Step 1)

         - Oxidation Catalyst
         - Good Combustion Practices

      ii. Available and feasible (Step 2)

      An oxidation catalyst is a post-combustion technology that removes CO from the exhaust gas stream after formation in the combustion turbine. In the presence of a catalyst, CO will react with oxygen present in the exhaust stream, converting it to carbon dioxide. No supplementary reactant is used in conjunction with an oxidation catalyst. The oxidation of CO to $CO_2$ utilizes the excess air present in the turbine exhaust; and the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of $PM_{10}$ and $H_2SO_4$ emissions.

      CO catalytic oxidation reactors operate in a relatively narrow temperature range. Optimum operating temperatures for these systems generally fall into the range of 700 °F to 1100 °F. At lower temperatures, CO conversion efficiency falls off rapidly. Above 1200 °F, catalyst sintering may occur, thus causing permanent damage to the catalyst. For this reason, the CO catalyst is strategically placed within the proper turbine exhaust lateral distribution (it is important to evenly distribute gas flow across the catalyst) and proper operating temperature at base load design conditions. Operation at partial load, or during startup/shutdown will result in less than optimum temperatures and reduced control efficiency.

      Typical pressure losses across an oxidation catalyst reactor (including pressure loss due to ammonium salt formation) are in the range of 0.7 to 1.0 inches of water. Pressure drops in this range correspond roughly to a 0.15 percent loss in power output and fuel efficiency or approximately 0.1 percent loss in power output for each 1.0 inch of water pressure loss.

      Catalyst systems are subject to loss of activity over time. Since the catalyst itself is the most costly part of the installation, the cost of catalyst replacement should be considered on an annualized basis. Catalyst life may vary from the manufacturer's typical 3-year guarantee to a 5- to 6-year predicted life. Periodic testing of catalyst material is necessary to predict annual catalyst life for a given installation.

Oxidation catalysts have been employed successfully for two decades on natural gas combustion turbines. An oxidation catalyst is considered to be technically feasible for application to this project.

Good combustion practices consisting primarily of controlled fuel/air mixing and adequate temperature and gas residence time are used to minimize the formation of CO. Good combustion practices are technically feasible for this project.

iii. Ranking of technologies for CO control (Step 3)

The most effective technologies that are available for a large natural gas-fired, combined cycle power generating facility for controlling CO are good combustion practices to control the formation of CO, and oxidation catalyst as a post-combustion treatment.

iv. BACT (Step 4)

Dominion has proposed a combination of control options for CO: oxidation catalyst and good combustion practices. The draft permit proposes use of oxidation catalyst and good combustion practices to control CO emissions from the CTs to the following level (at 15% $O_2$):

- 1.5 ppmvd without duct burning
- 2.4 ppmvd with duct burning

Compliance with the limits is to be based on a one-hour block average.
As shown in EPA's RBLC, only a few projects have been permitted at CO emission rates below 2 ppmvd at 15% $O_2$. Typically, CO emission rates of 2 ppmvd at 15% $O_2$ to 3.5 ppmvd at 15% $O_2$ are determined to be BACT and LAER. The higher CO emission rates generally account for the higher emissions associated with duct burning.

The most recent BACT determinations in the RBLC have been around 1.5 ppmvd at 15% $O_2$ or higher. The most relevant BACT determination was for the 2010 permit for the Warren County, Virginia power plant with BACT emissions set at 1.5 ppmvd at 15% $O_2$ without duct burning, and 2.4 ppmvd at 15% $O_2$ with duct burning. DEQ concurs that the proposed oxidation catalyst control, along with good combustion practices, constitute BACT for CO from the CTs.

b. Auxiliary Boiler and Fuel Gas Heaters

i. List of control technologies (Step 1)
- Good combustion practices
- Oxidation catalyst

ii. Technical feasibility and availability of CO Control (Step 2)
- Good combustion practices are feasible and available for these units
- Oxidation catalyst is feasible and available for these units

iii. Ranking of technologies (Step 3)
- Good combustion practices can result in emissions from the units of 0.037 lb/MMBtu

- Oxidation catalyst could reduce emissions further to about 0.006 lb/MMBtu

iv. BACT determination (Step 4)

- Oxidation catalyst used in conjunction with good combustion practices reduces CO emissions from the boiler by only 9 tons/yr at a cost of $10,000 per ton, and, for the fuel gas heaters, 1.1 tons/yr at $65,000 per ton, making it economically infeasible
- Good combustion practices results in CO emissions that are consistent with BACT at similar facilities. DEQ concurs with Dominion that good combustion practices are BACT for CO from the auxiliary boiler and fuel gas heaters.

c. Emergency Generators and Fire Water Pump
The control of CO from the emergency units can be achieved without the use of add-on CO controls which can be problematic on stationary combustion units. The units can meet NSPS standards for engines through proper operation and maintenance of the units, and burning of cleaner fuels. Therefore BACT for CO from the emergency unit will be the use of clean fuel and the proper operation and maintenance of the units to keep CO emissions at 2.611 g/hp-hr for the diesel units and 129.1 g/hp-hr for the propane unit.

4. $SO_2$ and sulfuric acid mist – primarily formed from the combustion of sulfur-containing fuels, with a small contribution of $H_2SO_4$ from the SCR and Oxidation catalyst controls.

a. Combustion Turbines
The use of low-sulfur fuels is the only feasible and available technology to reduce $SO_2$ and $H_2SO_4$ emissions from a natural gas combustion turbine. Flue gas desulfurization is only feasible on plants that produce much larger quantities of $SO_2$ and $H_2SO_4$ and would produce a significant pressure drop that would require an induced draft fan, potentially causing air/fuel mixing problems. The best low-sulfur fuel is natural gas which is what is proposed at this facility. The sulfur content of the natural gas is dependent on the location from which the gas is piped. The sulfur content of the natural gas to be used in Brunswick County is 0.4 gr/100 dscf (levels across the country can range from 0.2 gr to 2.0 gr/100 dscf) and cannot be controlled by Dominion. DEQ concurs with the proposed use of pipeline quality natural gas to achieve the following BACT rates:

- 0.00112 lb/MMBtu for $SO_2$
- 0.00058 lb/MMBtu for $H_2SO_4$ without duct burning
- 0.00067 lb/MMBtu for $H_2SO_4$ with duct burning

b. Auxiliary boiler and fuel gas heaters
The only feasible control for $SO_2$ and $H_2SO_4$ from the auxiliary boiler and fuel gas heaters is the use of pipeline quality natural gas.

c. Emergency generators
The use of ultra low sulfur diesel in the diesel generators (S = 15 ppm) and the use of propane in the propane generator at 500 hrs/yr are considered BACT for $SO_2$ and $H_2SO_4$ from the emergency units.

5. VOC - Formation of VOC emissions are attributable to the same factors as described for CO emissions above. VOC emissions are a result of incomplete combustion of carbonaceous fuels, and this is influenced primarily by the temperature and residence time within the combustion zone.

a. Combustion Turbines

i. List of possible VOC controls for combustion turbines (Step 1)

- Oxidation catalyst
- Good combustion practices

ii. Available and Feasible technologies (Step 2)

An oxidation catalyst is a post-combustion technology that removes VOC from the exhaust gas stream after formation in the combustion turbine. In the presence of a catalyst, VOC will react with oxygen present in the exhaust stream, converting it to carbon dioxide and water vapor. The performance of an oxidation catalyst is affected by the VOCs that are actually emitted. No supplementary reactant is used in conjunction with an oxidation catalyst. An oxidation catalyst is considered to be available and technically feasible for application to this project.

Good combustion practices consisting primarily of controlled fuel/air mixing and adequate temperature and gas residence time are used to minimize the formation of VOCs. This option is available and technically feasible.

iii. Ranking of technologies for VOC control (Step 3)
The most effective technologies that are available for a large, natural gas-fired, combined cycle power generating facility for controlling VOC are good combustion practices to control the formation of VOC, and oxidation catalyst as a post-combustion treatment.

iv. BACT (Step 4)
VOC emission rates for recently permitted combined-cycle facilities are typically in the range of 1.0 ppmvd at 15% $O_2$ to 2.0 ppmvd at 15% $O_2$ as shown in Dominion's summary of EPA's RBLC. The emission limits at the higher end of the range reflect the higher emissions associated with duct burning. However, there are a few projects with both higher and lower emission rates. Most of the projects with emission rates below 1.0 ppmvd at 15% $O_2$ have not been built. The 2010 permit for the Warren County power plant set BACT limits for VOC from the turbines at 0.7 ppmvd at 15% $O_2$ without duct burning, and 1.6 ppmvd at 15%$O_2$ with duct burning.

The applicant has proposed to control VOC using good combustion practices and an oxidation catalyst for the combustion turbines. The oxidation catalyst is proposed for the dual purpose of controlling CO emissions and VOC emissions. The applicant proposed VOC limits, based on 35% control by an oxidation catalyst, as follows, all at 15% $O_2$ and as $CH_4$ (calculated as a three-hour average):

- 0.7 ppmvd without duct burner firing
- 1.6 ppmvd with duct burner firing

DEQ concurs that the use of good combustion control and an oxidation catalyst represent BACT for VOC control for the proposed combustion turbines.

b. Auxiliary boiler and fuel gas heaters

i. List of control technologies (Step 1)
- Good combustion practices
- Oxidation catalyst

ii. Technical feasibility and availability of VOC Control (Step 2)
- Good combustion practices are feasible and available for these units
- Oxidation catalyst is feasible and available for these units

iii. Ranking of technologies (Step 3)

- Oxidation catalyst used in conjunction with good combustion practices would achieve the best control rate.
- Good combustion practices alone can result in emissions of VOC from the units of 0.005 lb/MMBtu

iv. BACT determination (Step 4)
VOC emissions from the boiler and fuel gas heaters without oxidation catalyst would be 0.005 lb/MMBtu which results in a combined total of 2.0 tons/yr from both units. It would not be economically feasible to reduce emissions further with add-on controls. Good combustion practices results in VOC emissions that are consistent with BACT at similar facilities at 0.005 lb/MMBtu. DEQ concurs with Dominion that good combustion practices are BACT for VOC from the auxiliary boiler and fuel gas heaters.

c. Emergency generators and fire water pump
The use of good combustion practices in the emergency generators and operating at 500 hrs/yr are considered BACT for VOC from the emergency units.

d. Fuel Tank
VOC emissions from the diesel fuel tank are estimated to be only 7.5 lbs/yr. The use of a fixed roof tank to hold diesel fuel is BACT for this type of unit.

6. Particulate Matter Controls ($PM_{10}$ and $PM_{2.5}$, including condensable) – Particulate matter emissions are a combination of filterable (front-half) and condensable (back-half) particulate. Filterable particulate matter is formed from impurities contained in the fuels and from incomplete combustion. Condensable particulate emissions, which contribute to $PM_{10}$ and $PM_{2.5}$ but not PM, are attributable primarily to the formation of sulfates and possibly organic compounds.

a. Combustion Turbines

i. List of PM control technologies (Step 1)

- Low ash/low sulfur fuel
- Add-on controls such as ESP, scrubbers or baghouses
- Proper combustion controls

ii. Available and technically feasible technologies (Step 2)

The use of low-ash fuels, like natural gas, propane, and ultra low sulfur diesel fuel are readily available and technically feasible to use in combined cycle turbines.

Add-on PM controls (such as ESPs, scrubbers or baghouses) are not recommended for combustion turbines burning natural gas because the PM particles are quite small (<1 micron) and the air volume is quite large, thus diluting PM. Add-on controls are not available nor technically feasible for a combustion turbine.

The use of low-ash fuel (natural gas) and good combustion practices are widely accepted as PSD BACT for $PM_{10}$ and $PM_{2.5}$ from combustion.

iii. Ranking of $PM_{10}$ and $PM_{2.5}$ control technologies (Step 3)
The most stringent particulate control method demonstrated for gas turbines is the use of low ash and low sulfur fuel with good combustion practices. No add-on control technologies are listed in EPA's RBLC. Proper combustion control and the firing of

fuels with negligible or zero ash content and a low sulfur content for the combustion turbines is the only control method listed.

iv. BACT for $PM_{10}$ and $PM_{2.5}$ (Step 4)
The pipeline quality natural gas in this region contains 0.4 gr/100 dscf which impacts the $PM_{10}$ and $PM_{2.5}$ emissions from fuel-burning (compared to the 0.1 gr/100 dscf to be used at the similar plant in Warren County, VA). In addition, the use of SCR and oxidation catalyst to control other air pollutants can contribute to $PM_{10}$ and $PM_{2.5}$ emissions. For this reason, BACT from this facility will be slightly higher than BACT for $PM_{10}$ and $PM_{2.5}$ from the Warren County plant. The applicant proposes the use of good combustion practices for the combustion turbines at the following BACT rates for $PM_{10}$ and $PM_{2.5}$:

$PM_{10}$
• 9.7 lb/hr (0.0033 lb/MMBtu) without duct burner firing (3-hour average)
• 16.3 lb/hr (0.0047 lb/MMBtu) with duct burner firing (3-hour average)

$PM_{2.5}$
• 9.7 lb/hr (0.0033 lb/MMBtu) without duct burner firing (3-hour average)
• 16.3 lb/hr (0.0047 lb/MMBtu) with duct burner firing (3-hour average)

DEQ concurs that the use of good combustion practices represents BACT for $PM_{10}$ and $PM_{2.5}$ control for the proposed combustion turbines.

b. Auxiliary Boiler and Fuel Gas Heaters
Particulate matter emissions from the boiler and fuel gas heaters are a combination of filterable and condensable particulate. Good combustion practices and limiting fuel use to only pipeline quality natural gas are proposed by the applicant as BACT for $PM_{10}$ and $PM_{2.5}$ emissions from the auxiliary boiler and fuel gas heaters. DEQ agrees that this constitutes BACT for particulate emissions from the boiler and heaters. Short-term $PM_{10}$ and $PM_{2.5}$ emissions from the auxiliary boiler and the fuel gas heaters will be limited to 0.007 lbs/MMBtu. Annual $PM_{10}$ and $PM_{2.5}$ emissions from the auxiliary boiler will be limited to 2.2 tons/yr while emissions from the fuel gas heaters will be limited to 0.8 tons/yr.

c. Fire Pump and emergency generators
Possible PM controls for an emergency generator consist of the following: catalysts, including diesel particulate filters, clean fuels and good combustion practices. Of these, catalysts are not used for units that are only run on an as-needed basis, making them not technically feasible for this unit. Therefore, PSD BACT for $PM_{10}$ and $PM_{2.5}$ from the emergency generator units shall be the use of clean fuels (i.e., ULSD or propane) and good combustion practices to achieve the following emission limits:

| Unit | BACT Limit | |
|---|---|---|
| | $PM_{10}$ | $PM_{2.5}$ |
| EG-1 | 0.298 g/hp-hr | 0.298 g/hp-hr |
| EG-2 | 0.0194 g/hp-hr | 0.0194 g/hp-hr |
| FWP-1 | 0.298 g/hp-hr | 0.298 g/hp-hr |

d. Cooling Towers
Cooling towers produce drift, which is composed of fine water droplets that may contain dissolved solids and thus contribute to $PM_{10}$ and $PM_{2.5}$ emissions. The only feasible particulate matter controls for cooling towers is to use water with low total dissolved solids content and drift eliminators. The facility will use clean cooling water with drift eliminators in the inlet chillers and clean cooling water in the AEC.

i. Auxiliary Equipment Cooler

BACT for PM from the AEC will be to keep dissolved solids below 300 mg/l and to achieve a drift rate of 0.01 percent of the circulating water flow (equivalent to 0.0008 TPY of $PM_{10}$ and $PM_{2.5}$.

ii. Inlet Chillers

BACT for PM from the Inlet Chillers will be to keep dissolved solids below 1,000 mg/l and to achieve a drift rate of 0.0005 percent of the circulating water flow (equivalent to 0.029 TPY of $PM_{10}$ and $9.46 \times 10^{-5}$ TPY of $PM_{2.5}$.

Table 4 below summarizes BACT for the facility:

| Pollutant | Primary BACT | Control | Compliance |
|---|---|---|---|
| $NO_x$ | Turbine<br>2.0 ppmvd @ 15% $O_2$ (1-hour avg.) | DLN burners<br>SCR | Annual fuel throughput<br>Stack test<br>NOx CEMS |
| | Auxiliary Boiler and fuel gas heaters<br>9 ppmvd | DLN burners | Annual fuel throughput<br>Stack test |
| | Emergency Generators<br>EG-1 6.4 g/kW-hr NOX+NMHC<br>FWP-1 4.0 g/kW-hr NOX+NMHC<br>EG-2 5.84 g/kW-hr | Good combustion practices | Annual hours of operation |
| $SO_2$ | Turbine<br>0.00112 lb/MMBtu | Low sulfur fuel | Fuel monitoring, stack test |
| | Auxiliary boiler and fuel gas heaters<br>0.00112 lb/MMBtu | Low sulfur fuel | Fuel monitoring |
| | Emergency generators<br>0.00154 lb/MMBtu (diesel)<br>0.00059 lb/MMBtu (propane) | ULSD fuel with 15 ppm S<br>Or propane fuel | Fuel certification and hours of operation |
| $H_2SO_4$ | Turbine<br>0.00058 lb/MMBtu without DB<br>0.00067 lb/MMBtu with DB | Low sulfur fuel | Fuel monitoring, stack test |
| | Auxiliary boiler and fuel gas heaters<br>0.00857 lb.MMBtu | Pipeline quality natural gas and 5% oxidation of S to $H_2SO_4$ | Fuel monitoring |
| | Emergency generators (see $SO_2$) | (see SO2) | Fuel monitoring |
| CO | Turbine<br>1.5 ppmvd without DB (3-hour avg.)<br>2.4 ppmvd with DB (3-hour avg.) | Oxidation catalyst<br>Good combustion practices | CO CEMS |
| | Auxiliary boiler and fuel gas heaters<br>50 ppmvd | Clean fuel and good combustion practices | Stack test |
| | Emergency generators<br>3.5 g/kW-hr (diesel)<br>174.4 g/kW-hr (propane) | Good combustion practices | Fuel monitoring |
| $PM_{10}$ and $PM_{2.5}$ | Turbine<br>9.7 lbs/hr (0.0033 lb/MMBtu) without DB (3-hour avg.)<br>16.3 lbs/hr (0.0047 lb/MMBtu) with DB (3-hour avg.) | Low sulfur/carbon fuel and good combustion practices | Stack test |
| | Auxiliary boiler and fuel gas heaters<br>0.007 lb/MMBtu | Low sulfur/carbon fuel and good combustion practices | Fuel throughput |
| | Emergency generators<br>0.40 g/kW-hr (diesel)<br>0.12 g/kW-hr (propane) | Low sulfur fuel and good combustion practices | Hours of operation |
| | Turbine Chiller<br>Drift rate of 0.0005% of circulating water flow and TDS of no more than 1,000 mg/l | Low total dissolved solids (TDS) and drift eliminators | Weekly water quality testing for TDS |
| | Auxiliary Cooler<br>Drift rate of 0.01% and TDS content of no more than 300 mg/l | Low TDS | Weekly water quality testing for TDS |
| VOC | Turbine<br>0.7 ppmvd without (3-hour avg.)<br>1.6 ppmvd with DB (3-hour avg.) | Oxidation catalyst<br>Good combustion practices | stack test and CO CEMS compliance |
| | Auxiliary boiler and fuel gas heater<br>0.005 lb/MMBtu | Clean fuel and good combustion practices | Fuel throughput |
| | Emergency generators (see NOx limit) | | Hours of operation |

| Pollutant | Primary BACT | Control | Compliance |
|---|---|---|---|
| $CO_2e$ | Turbine<br>7,500 Btu/kWh (HHV net) and 920 lb/MWh | Energy efficient combustion practices and low GHG fuels | ASME Performance Test Code on Overall Plant Performance (PTC 46) and $CO_2$ CEMS (Part 75) and maintenance. |
| | Auxiliary boiler and fuel gas heaters<br>117 lb/MMBtu | Pipeline quality natural gas and fuel-efficient design and operation | Manufacturer specifications and maintenance. |
| | Emergency Units<br>0.00661 lb/MMBtu | Fuel-efficient design | fuel usage monitoring |
| | Electrical Circuit breakers<br><1% leakage rate | Enclosed-pressure type breaker and leak detection | Audible alarm with decreased pressure. |

The proposed control strategies are considered to be the Best Available Control Technology (BACT) for this source type and are more stringent than NSPS standards.

IV. Initial Compliance Determination

A. Testing – stack testing is required for $NO_x$, $SO_2$, CO, VOC, $PM_{10}$, and $PM_{2.5}$ from the turbines and $NO_x$ and CO from the auxiliary boiler and fuel gas heaters to show compliance with the BACT limits. An initial compliance test using ASME Performance Test Code on Overall Plant Performance (ASME PTC 46-1996) (or equivalent) is to be conducted on the turbine power blocks to show compliance with the heat rate limit of 7,500 Btu/kWh (HHV net).

The permit allows the permittee to use the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel to verify that the sulfur content of the natural gas is 0.4 grain or less of total sulfur per 100 standard cubic feet. Alternatively, per 40 CFR 60.4370, the permit allows Dominion to determine the sulfur content of the natural gas by testing using two custom monitoring schedules or an EPA-approved schedule. The permit also requires the permittee to obtain fuel supplier certification for each shipment of distillate oil used in the emergency units.

B. VEEs – an initial VEE will be required for the combustion turbines.

V. Continuing Compliance Determination

A. CEMS – will be required for $NO_x$ (NSPS) and is also proposed for CO and $CO_2$. Requirements for CEMS performance evaluations, quality assurance, and excess emissions reports will be included in the permit.

The permit requires that the CT stacks be equipped with CEMS meeting the requirements of 40 CFR Part 75 (Acid Rain program) for $NO_x$. In addition to providing a means to demonstrate compliance with the permit $NO_x$ limits, the CEMS will satisfy the NSPS Subpart KKKK requirement to monitor $NO_x$ emissions using a CEMS. The permit also requires that the CT stacks be equipped with CEMS meeting the monitoring requirements in 40 CFR 60.13 for CO.

In addition to the CEMS, the draft permit requires Dominion to conduct extensive, continuous monitoring of key operational parameters on the control devices to assure proper operation and performance.

B. Recordkeeping – The following records will be kept by the permittee for the most recent five years:

a. Annual hours of operation of the emergency fire water pump (FWP-1) and emergency generators (EG-1 and EG-2) for emergency purposes and for maintenance checks and readiness testing, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

b. All fuel supplier certifications for the ULSD fuel used in the emergency units (EG-1and FWP-1);

c. Monthly and annual throughput of natural gas to the three combustion turbines and associated duct burners (T-1M, T-2M, and T-3M), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

d. Time, date and duration of each startup, shutdown, and malfunction period for each combustion turbine and associated duct burner (T-1M, T-2M, and T-3M);

e. Monthly and annual throughput of natural gas to the auxiliary boiler (B-1) and the fuel gas heaters (GH-1 through GH-3), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months;

f. Fuel quality records for natural gas combusted in the combustion turbine and associated duct burner (T-1M, T-2M, and T-3M);

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

h. Operation and control device monitoring records for each SCR system and oxidation catalyst as required in Conditions 3 and 7;

i. Weekly logs of dissolved solids content of cooling water to the four inlet coolers (IC-1 through IC-4) and the auxiliary equipment chiller (AEC-1).

j. Scheduled and unscheduled maintenance, and operator training.

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

l. Manufacturer’s instructions for proper operation of equipment.

C. Further Testing

a. Annual testing for $SO_2$ can be done instead of fuel monitoring.

b. After the initial test for heat rate of the power block, an additional test is required every five years.

VI. Public Participation

The applicant held a public information session on March 8, 2012 at the High School in Lawrenceville, Brunswick County to provide the community with information about the project.

Pursuant to 9 VAC 5-80-1775 (Article 8) of the Regulations, the proposed project is subject to a public comment period of at least 30 days, followed by a public hearing.

An information meeting and public hearing is scheduled to be held on February 4, 2013 at the Meherrin Library, Brunswick Branch, followed by 15 more days of public comment.

The following documents are attached:

A. Public hearing notice

B. Public hearing opening statement

C. Public briefing

D. Virginia Register notice

E. Documents concerning public comment period

VII. Other Considerations

A. File Consistency Review – This is the first permit action for this source

B. PRO Policy Consistency Review – A review of similar combustion turbine permits proposed or issued in the USA was conducted. The most recent boilerplate was used for this permit.

C. Confidentiality – The source has not claimed confidentiality of any data.

D. Permit History – This is the first permit issued for this source

VIII. Recommendations

Based on the information submitted, it is recommended that this permit be issued. Recommendations and limitations are provided in the draft permit letter.

Regional Engineer:_____________________ Date: ____________________

Reviewing Engineer:_____________________ Date: ____________________

Attachments: Permit application
Local Governing Body Certification Form
Calculation sheets
Modeling Memo
Public Participation documents