VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY
Piedmont Regional Office
INTRA-AGENCY MEMORANDUM
Engineering Analysis

Permit Writer	Alison M. Sinclair
Air Permit Manager	James E. Kyle
Memo To	File
Date	August 8, 2025
Facility Name	Dominion Chesterfield Power Station
Registration Number	50396
Application No.	42
Date Fee Paid	December 18, 2019
Amount ($)	$69,300
Distance to SNP (km)	144 km
Distance to JRF (km)	175 km
FLM Notification (Y/N)	Y
Application Fee Classification	Major
Permit Writer Signature	
Permit Manager Signature	

I. Introduction

The Dominion Chesterfield Power Station has been in operation since the 1940s, originally using steam boilers to power turbines to generate electricity. The facility shut down two coal boilers in 2019 and two other coal boilers in 2023. The facility no longer combusts coal. The facility currently operates two combined-cycle combustion turbines (Units #7 and #8 constructed in 1990). Virginia Electric and Power, dba. Dominion Energy Virginia owns the property which extends from the CSX railroad to the west, the James River on the northern edge of the property site, Chesterfield County's Henricus Historical Park to the east, and Chesterfield County's Dutch Gap Conservation Area to the south.

The facility submitted a permit application on December 16, 2019 (revised on August 1, 2023; August 21, 2024; September 26, 2024, and March 3, 2025) to construct and operate a stationary, simple-cycle, dual fuel-fired (natural gas/distillate oil), electric power generation facility (aka Chesterfield Energy Reliability Center or CERC), operated for generation of electric power during periods of high demand, seasonal peaks, and extreme temperature events, as well as when intermittent generation sources, like solar or wind, are unavailable or insufficient to meet customer need. The CERC will consist of four 250 MW simple-cycle combustion turbines (SCCTs), one fuel gas heater, seven black start generators, a large fuel oil tank for the turbines, and seven smaller fuel tanks for the black start generators. Additionally, the facility will include 16 electrical circuit breakers and natural gas piping components which do not have exhaust points but will be monitored for leaks of greenhouse gas constituents. The SCCTs are proposed to combust primarily natural gas fuel with fuel oil as a secondary source. The SCCTs will also have the capability of combusting natural gas mixed with hydrogen (H_2).

The current Chesterfield Power Station is an existing stationary source located in an area that is zoned for industrial operations. This proposed major modification required the submission of a Local Governing Body Certification Form (LGBCF). On April 4, 2024, Chesterfield County submitted a written determination to Dominion that the location and operation of the CERC 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. A signed LGBCF was received by DEQ in the August 21, 2024 revised application.

Section 10.1-1307E of the Code of Virginia specifies that the Department, in issuing a permit, shall consider facts and circumstances relevant to the reasonableness of the activity involved and the regulations proposed to control it, including:

- §10.1-1307.E.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
- §10.1-1307.E.2 - The social and economic value of the activity involved, and
- §10.1-1307.E.3 - The suitability of the activity to the area in which it is located, except that consideration of this factor shall be satisfied if the local governing body of a locality in which a facility or activity is proposed has resolved that the location and operation of the proposed facility or activity is suitable to the area in which it is located.
- §10.1-1307.E.4 – The scientific and economic practicality of reducing or eliminating the discharge resulting from such activity.

The drafted permit has taken into consideration that the proposed activity at this site will not be dangerous or harmful.

The facility may provide an explanation of the social and economic values of the proposed facility or activity to aid DEQ in its consideration of the proposed project. Regarding the second bullet item, the revised application received in September 2024 (and revised March 2025) included a report conducted by Mangum Economics discussing the social and economic value of the proposed facility (permit application Appendix H.2, Attachment 1). After consideration of the information in this report and other sources, DEQ finds that the project would provide economic value to the county in the form of job creation and tax revenue. When called upon, this plant will stabilize the grid by rapidly supplementing electric generation from renewable sources in times of high demand (very hot days or very cold nights) or decreased electric generation (due to darkness, calm winds, low temperatures), preventing grid stress (which might trigger a region-wide power outage). By shutting down and demolishing the coal units at this facility and installing cleaner technologies on the same site, this project reduces land disturbance and construction of additional infrastructure and reduces pollution.

Regarding the third bullet item, the DEQ Site Suitability Form is usually reviewed by a local government entity, and they indicate whether the site is suitable for the proposed activity or not. In lieu of a signed Site Suitability Form, Chesterfield County indicated in a letter dated June 24, 2024 that the location of the CERC at 500 Coxendale Rd, adjacent to the current power station, and operated similarly to the existing power turbines, would not necessitate any additional approval by the county. DEQ considers this a determination by Chesterfield that the Coxendale Road site (existing Chesterfield Power site) is suitable for this project. DEQ agrees with Chesterfield County's position that the site is suitable for the CERC project based on the results of air quality analysis. The fact that the site has historically operated as a fossil-fuel fired generation station and, as indicated by Dominion's March 3, 2025 suitability analysis (Appendix H), the nearest residence is approximately a mile away, along with the emission reductions occurring at this site, support this.

The fourth bulleted item is addressed in Sections IV and VI.

The federal Clean Air Act, the National Ambient Air Quality Standards (NAAQS), the State Air Pollution Control Law and the State Air Control Regulations were established and designed to protect the environment and health for all people. The air quality analysis (see Section VI) indicates emissions from the facility will not exceed any of the applicable ambient air quality standards as permitted. The air permit process used by DEQ and the requirements contained in the resulting draft permit are intended to ensure no disproportionately high and adverse air quality impact on any resident of Virginia.

The facility is in an area that is in attainment with all NAAQS, meaning that the air monitoring network has shown that, currently, the air in central Virginia meets the federal standards set for certain air pollutants to protect public health and welfare and is used to determine if any person is experiencing an adverse impact.

The Environmental Justice Act (Article 12, §2.2-234 to 235) was promulgated in 2020 and states "It is the policy of the Commonwealth to promote environmental justice and ensure that it is carried out throughout the Commonwealth, with a focus on environmental justice communities and fenceline communities." Environmental justice is further described as "the fair treatment and meaningful involvement of every person, regardless of race, color, national origin, income, faith, or disability, regarding the development, implementation, or enforcement of any environmental law, regulation, or policy." Fair treatment is defined to mean no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental, and commercial operations or policies. DEQ has taken several actions in pursuit of the environmental justice principles of fair treatment and meaningful involvement.

As noted in Sections IV (BACT) and VI (Dispersion Modeling) below, the stationary source complies with all applicable requirements and ambient air quality standards. After imposition of the BACT control measures, the project's emissions have been minimized. Air quality modeling demonstrates that the air quality impact of the pollutants with permitted emissions greater than the respective rates deemed significant are all in accordance with the applicable NAAQS. The SCCTs are proposed to combust primarily natural gas fuel (with or without H_2) with fuel oil as a secondary source.

<u>Notifications, communications, and outreach:</u>
Throughout the draft permit development, DEQ staff were available to answer questions from community leaders and the general public. The DEQ has maintained a webpage dedicated to this project containing links to all public documents for the project, as they became available, and noting the contact information for the permit writer.

Dominion conducted a mandatory informational briefing for the community on November 16, 2023, and several voluntary outreach activities throughout 2023 and 2024. They also published project information on their website. Appendix H of the March 3, 2025 permit application included an in-depth analysis on Environmental Justice and information about outreach they had conducted.

During the permit application review and drafting period, Dominion conducted many voluntary outreach activities in the surrounding communities (see APPENDIX B) to this document). As required by 9VAC5-80-1775.K, Dominion published a notice in the Richmond Times-Dispatch newspaper including details of the project at least 60 days before the end of the public comment period. Additionally, they sent this notice to adjacent property owners, public libraries and schools within five miles of the facility, and to the elected officials of the locality affected. DEQ posted this notice on its website and social media accounts.
DEQ held a public briefing to provide information about the application and to answer questions. The DEQ advertised a notice of the public briefing in the Richmond Times-Dispatch newspaper on July 7, 2025. Notices were placed at many public, commercial, and community locations within the surrounding area in both English and Spanish, advertising the briefing. The public briefing was held at the SpringHill Suites Chester in Chesterfield County on August 7, 2025.

When the draft documents were ready for public comment, a public notice was advertised in the Richmond Times-Dispatch on August 8, 2025 announcing the public hearing date, time, and location. This notice was also posted on the DEQ website and emailed to the public notice mailing list, and to local officials in the surrounding jurisdictions. Flyers were posted throughout the community in English and in Spanish. The associated draft documents were available to the public on the DEQ website, by request, or in person, by appointment.

Public comments will be received in writing in person, by postal mail and by email for 60 days following the briefing. The public hearing will be held on September 8, 2025 to obtain oral comments and written comments from attendees. Written comments are accepted in person, electronically by email, or by postal mail throughout the 60-day public comment period, pursuant to 9VAC5-80-1775.

DEQ and Dominion’s outreach, both required by law and voluntary, meet the process-based requirement of meaningful involvement under the EJ Act.

No part of the permit decision can be finalized until DEQ has considered each of the comments received from the public on this permit action. Additional discussion of public participation is contained in Section XI.

II. Emission Units/Process Description

VEPCO, dba Dominion Energy Virginia, is proposing to construct and operate a new, nominal 1,000-megawatt (MW) net generating capacity at ISO conditions, simple cycle electrical power generating facility (equipment specifications are preliminary at this stage, however the proposed size and emissions from proposed units would reflect the most conservative emissions expected from the equipment to be installed). The affected emissions units at the facility will consist of the following:

- Four dual-fuel-fired simple cycle combustion turbines, with natural gas being the primary fuel (possibly combined with up to 10% hydrogen) with fuel oil as a secondary source.
- Seven diesel-fired black start engine generator sets

- Eight fuel oil storage tanks (one for the turbines and seven for the black start generators)
- A natural gas-fired fuel gas heater
- Natural gas piping components; and
- Six electrical circuit breakers.

A. Four Simple Cycle Combustion Turbine Generators (ES-33, ES-34, ES-35, ES-36)

The source has proposed the installation of four GE 7FA-05 (or equivalent) SCCTs with a net electrical generating capacity of 250 MW each. The primary fuel combusted in the turbines will be 100% natural gas consumed at 2,445 million Btu/hour (MMBtu/hr) each, but they will be allowed to mix up to 10% hydrogen into the natural gas combusted at 2,449 MMBtu/hr each. Alternatively, fuel oil will be allowed to be combusted at 2,452 MMBtu/hr for up to approximately 750 hours per year per turbine (see second bullet below).

<u>Each</u> turbine will be permitted to operate in any of the following scenarios:

- Scenario 1: Turbine is limited to no more than 7,927,050 MMBtu/yr heat input (approximately 3,240 hours) for normal operation per 12-month rolling total.
- Scenario 2: No more than 1,839,000 MMBtu/yr heat input (approximately 750 hours) for normal operation while combusting #2 fuel oil per 12-month rolling total (with the remainder of operation on natural gas, with or without hydrogen).

<u>All</u> the turbines will be permitted as follows:

- No more than 2,000 startups (combined) on natural gas and no more than 480 startups (combined) on #2 fuel oil per 12-month rolling total.
- No more than 2,000 shutdowns on natural gas (combined) and no more than 480 shutdowns (combined) on #2 fuel oil per 12-month rolling total.

The short-term permit emission limits represent the most conservative operation for each pollutant, as proposed by GE, considering variable loads (100% to under 50%), various ambient temperatures (107° F to -10° F), relative humidity (60% to 35%), and fuel type (natural gas, natural gas with 10% H_2, or #2 fuel oil). Units for each limit (lb/MMBtu, lb/hour, ppmvd) may represent different scenarios. Also, averaging time for each limit is stated for compliance demonstration, as necessary. Compliance with these limits will be based on stack tests and/or continuous emission monitoring systems (CEMS, fuel monitoring specifications), and demonstration of proper operation of the equipment and any associated air pollution control equipment.

Alternative operating scenarios

- Emissions during startup and shutdown for NOx and CO (in lb/turbine/event) for both natural gas and #2 fuel oil were estimated on percent load, effectiveness of pollution control at load, fuel type being combusted, and duration of each event by the proposed turbine manufacturer (GE). Compliance with these limits will be based on CEMS.
- Low load emergency operation – it may be necessary, during electrical grid restoration, for the turbines to operate at low loads. This would only happen during a PJM ISO declared

emergency or during readiness testing. This would be a very uncommon scenario. If it should happen, NOx and CO emissions would be measured with CEMS, if operational.

- Turbine tuning consists of adjusting the air-to-fuel ratio under a wide range of load and atmospheric conditions in order to optimize turbine performance, while minimizing emissions. On a periodic and as-needed basis, planned maintenance of the turbine blades shall include tuning of the turbines. A tuning event could last up to 18 hours. During tuning, the turbines might not be able to meet the emission concentration or other short-term emission limits for NOx and CO on a four hour average due to fluctuations in air flow and fuel flow during tuning. Approximately 96 hours per year per turbine is expected to be utilized for this maintenance. NOx and CO would be measured by CEMS.
- Fuel type transfer occurs when a turbine needs to switch fuels, while operating. This can be done automatically or manually. The duration of this event would be relatively short. NOx emissions during such an event must comply with the NSPS Subpart KKKK limits and will be measured by CEMS on a 4-hr average. Other pollutant emissions will be calculated based on fuel throughput and load for the duration of the event.
- Green rotor run-in occurs when a rotor is replaced or refurbished. Such an event should not last longer than 12 hours. The turbine will need to be operated, without load, for the duration of the event, until the vibration measured during such an event meets with manufacturer specifications.

Annual permit emission limits are based on the most conservative fuel combustion scenario and also include startups, shutdowns, and other alternative operations, as limited by the permit. Compliance will be based on stack tests, CEMS, parametric monitoring, calculations, and recordkeeping of all operational limits in the permit.

B. Fuel gas heater (ES-37)

An 18.8 MMBtu/hour natural gas-fired fuel gas heater is proposed for this facility to heat the incoming natural gas to the turbines in cold temperatures, if necessary, to an optimum temperature to maximize combustion. The unit will be permitted to operate on a throughput of natural gas equivalent to 8760 hrs/year but is only expected to operate in colder weather.

C. Black start engine-generator sets (ES-38, ES-39, ES-40, ES-41, ES-42, ES-43, ES-44)

The source is proposing the installation of seven 3,500 kilowatt-electric (kWe) (nominal) diesel-fired emergency generators for the purpose of having “black start” capability. Six black start generators are necessary to provide electricity to start up a turbine if the electrical grid fails. Normally, a combustion turbine uses electricity from the grid to start up. During a grid failure, a turbine would not be able to start up to provide power for grid restoration and the electronic systems used to oversee the power station would not be operable. So, the black start generators would be used to start one of the SCCTs, which would then operate in low load emergency (LLE) mode until the grid power is restored. Although black start events would be very rare, these engine-generators are also allowed to operate during power outages (and for engine maintenance and testing) to provide electricity to the facility in case of a power outage. The permit allows each generator to operate for up to 500 hours in a 12-month period during such instances. This is to allow for flexibility and some redundancy (i.e., in case of a failure of a generator during an emergency).

D. Fuel storage tanks (TK3, TK4, TK5, TK6, TK7, TK8, TK9, TK10)

The facility proposes to install eight fuel oil storage tanks: one 12-million gallon tank to supply fuel oil to all four turbines and seven 3,500-gallon tanks to store diesel fuel for the black start engines. The storage tanks will be limited to holding only distillate oil. Distillate oil has a very low vapor pressure so vapors from the tanks are minimal (standing loss). Since the equipment being fueled by the distillate oil would not be operated frequently on that fuel, the expected working loss from the tanks, based on permitted throughput, is also minimal.

E. Leaking piping components (FUG-1)

The proposed project will be supplied by natural gas piping components. Some leakage of natural gas (primarily methane, which is a greenhouse gas) may occur at valves, flanges and other connections, and during repairs, venting, etc.

F. Electrical Circuit Breakers (CB1 through CB16)

The proposed project will include sixteen switchyard circuit breakers, each holding 224 lbs of sulfur hexafluoride (SF_6, a greenhouse gas) as an insulating agent.

III. Regulatory Review

A. Delegation of authority for aspects of this project

1. Federal Energy Regulatory Commission (FERC) is an independent agency that regulates the interstate transmission of electricity (and interstate transport of natural gas or oil by pipeline) and protects the reliability of this transmission system through mandatory reliability standards (https://www.ferc.gov)
2. Pennsylvania, New Jersey, Maryland Regional Transmission Organization (PJM) is an independent non-profit organization mandated by FERC to oversee the safety, reliability, and security of the bulk power transmission system in its territory, which includes all or part of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Washington, DC. (https://pjm.com).
3. Virginia State Corporation Commission (SCC) is an independent branch of state government. It has regulatory authority over utilities (among other duties). It has the power to set rates charged by large investor-owned utilities. They are also the central agency to keep files on companies that incorporate or create partnerships or LLCs created in Virginia (https://www.scc.virginia.gov).
4. Environmental Protection Agency (EPA) is a federal agency tasked with developing and enforcing federal regulations to protect the environment. The EPA Administrator can approve delegation of enforcement of some federal regulations to state agencies, if such delegation is requested by the state agency.

5. Virginia Department of Environmental Quality (DEQ) implements and enforces state and delegated federal environmental regulations (https://www.deq.virginia.gov).

B. 9VAC5 Chapter 80, Part II, Article 8 - PSD Major New Source Review:

Chesterfield County is a PSD area for all pollutants as designated in 9VAC5-20-205 (Article 9 Non-attainment major new source review does not apply). The facility is in the 100 TPY major source category.

A major modification for a PSD source is defined in 9VAC5-800-1615 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant, and a significant net emissions increase of that pollutant from the major stationary source." Note that greenhouse gases - CO_2, CH_4, and N_2O, multiplied by a Global Warming Potential (GWP) factor for each and then summed, is also known as CO_2 equivalent, or CO_2e - are not regulated pollutants until a source triggers PSD permitting for other regulated pollutants, which is the case for this project (9VAC5-85-40 Part III).

The addition of the CERC is considered a physical change that will increase actual emissions; therefore, it is a project under Article 8.

A project is a major modification for a regulated NSR pollutant if the project occurs at an existing major source and it satisfies the following Steps:

1. The project causes a significant emission increase (SEI); and
2. The project causes a significant net emissions increase (SNEI).

Step 1, determining the SEI, requires summing all of the emission increases associated with the project for each pollutant. If the result for a pollutant is less than the SEI rate, then there is not a SEI, and a major modification has not occurred for that pollutant. For pollutants that exceed the SEI rate, another step is required to determine if a SNEI has occurred.

Step 2, determining the SNEI, requires summing all of the emission increases associated with the project, and summing all of the other creditable increases and decreases in actual emissions at the facility during the contemporaneous time period. If the result is greater than the significant emission rate, then a major modification would occur, and the project is subject to PSD permitting.

The procedure for calculating whether a SEI will occur depends on the type of emissions units being modified. Since this project involves only new emissions units, the facility has utilized the emissions test contained in 9VAC5-80-1605.G(4). This test utilizes the baseline actual emissions (BAE) to future potential emissions test for each new unit. The BAE to future potential emissions test involves comparing the post-change potential emissions of the new emission units to the baseline actual emissions of these units.

For new units, the definition of BAE states "the baseline actual emissions for the purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall be the units' PTE." Since the project involves only new emissions units that have yet to be constructed, the BAE for each unit equals zero.

As shown in Table 1, the project causes an SEI for PM, PM10, PM2.5, CO, NOx, VOC, H_2SO_4, and CO_2e.

Table 1 - SEI Pollutant Summary (Step 1)

Pollutants	**Emissions Increase TPY**	**Significance Level TPY**	**SEI?**
PM	81.8	25	Yes
PM10	153.9	15	Yes
PM2.5	153.9	10	Yes
CO	825.3	100	Yes
NOx	353.3	40	Yes
SO_2	27.9	40	No
VOC	162.5	40	Yes
H_2SO_4	18.7	7	Yes
Lead	0.01	0.6	No
CO_2-e	2,214,344	75,000	Yes

At the time of the submission for the project on August 1, 2023, the commencement of construction of the CERC was planned for around April 2025 with an anticipated startup date of August 2027; therefore, the contemporaneous period extends from April 2020 (five-year lookback from proposed construction date) to August 2027. There were four contemporaneous projects identified. The creditable emissions increases were based on the permitted emission limits for each project since those projects did not have 24 months of emissions data available. The creditable decrease from the shutdown of boilers #5 and #6 were based on a 24-month average BAE between July 2020 and June 2022. Table 2 shows the results of the Step 2 SNEI determination for those pollutants from this project that caused a SEI (demonstrated in Table 1):

Table 2 - SNEI Pollutant Summary (Step 2)

Project	**PM**	**PM10**	**PM2.5**	**CO**	**NOx**	**VOC**	**H_2SO_4**	**CO_2e**
CERC	81.8	153.9	153.9	825.3	353.3	162.5	18.7	2,214,418
Boilers #5 & #6 shutdown (2023)	(277.8)	(222.0)	(44.0)	(165.3)	(453.6)	(19.3)	(428.0)	(1,700,338)
Ash pond (CCR) excavation (2021)	42.4	12.1	1.5	-	-	-	-	-
Ash beneficial use (2021)	4.5	2.5	2.1	18.4	3.8	3.1	0.02	2,317
Pipeline heater (2022)	0.01	0.02	0.02	3.0	3.5	0.2	0.02	3,819
Net Emissions "Increase"	(149.1)	(53.5)	113.5	681.7	(93.0)	146.6	(409.3)	520,142
PSD Significant	25	15	10	100	40	40	7	75,000
Subject to PSD?	No	No	**Yes**	**Yes**	No	**Yes**	No	**Yes**

In summary, any equipment that emits a pollutant that is subject to PSD Article 8 review is subject to Article 8 permitting for that pollutant. This would include all proposed equipment that emit PM2.5, CO, VOC, and CO_2e.

C. 9VAC5 Chapter 80, Part II, Article 6 - Minor New Source Review:

The provisions of Article 6 apply throughout Virginia to (i) the construction of any new source, (ii) the construction of any project (which includes the affected emission units), and (iii) the reduction of any stack outlet elevation at any stationary source.

This application is for a change that meets the definition of "project" contained in 9VAC5-80-1110.C. To be exempt from permitting, the regulations provide that a project must be exempt under both the provisions of 9 VAC5-1105.B through D as a group and the provisions of 9VAC5-80-1105.E and F.

The facility proposes construction of affected emission units listed in 9VAC5-8-1105.B, i.e., categorically exempt units. The seven diesel storage tanks used to hold fuel for the black start engine generators (with a vapor pressure less than 1.5 psia) are listed at 9VAC5-80-1105.B(4). The fuel gas heater is listed at 9VAC5-80-1105.B(1)(a)(4) & (b). These units will not be evaluated further for applicability to Article 6 permitting under 9VAC5-80-1105 for criteria pollutants.

Since this is a project at an existing facility, the exemption rates for a new facility in 9VAC5-80-1105.C are not used.

In determining if a project is exempt under 9VAC5-80-1105.D, a calculation of the uncontrolled emission rate (UER) increase from the project is required. The project's emission increase is the sum of the UER increases from each affected emissions unit not listed in 9VAC5-80-1105.B (see previous paragraph). An emissions unit's increase is the difference between the new UER after the project (NUE) and the current UER (CUE) for that emission unit and cannot be less than zero. All affected emissions units in this project are new; therefore, the CUE for each emission unit is zero.

As discussed in Section III.B above, the project is subject to the provisions of PSD (9VAC5-80 Article 8) for significant net emissions increases of PM2.5, CO, and VOC; therefore, in accordance with 9VAC5-80-1100.H, those pollutants are subject to more stringent requirements (see Section III.B for details) and need not be evaluated for Article 6 permitting. As shown in Table 3 below, the project is subject to the permitting requirements of Article 6 for PM, PM10, NOx, SO_2, and H_2SO_4.

Table 3 - Article 6 Uncontrolled Emissions Increase

Pollutant	CUE tons/yr	NUE tons/yr	Increase tons/yr	Exemption tons/yr
PM	0	423.0	423.0	15
PM10	0	791.8	791.8	10
NOx	0	7,082.8	7,082.8	10
SO_2	0	79.1	79.1	10
H_2SO_4	0	52.6	52.6	6

As discussed in Section III.F below, all the affected emissions units, except the fuel storage tanks, are in a source category subject to a standard promulgated pursuant to 40 CFR 63 (i.e., Subparts YYYY, ZZZZ, and DDDDD). None of those affected emissions units are subject to federal hazardous air pollutant new source review. Therefore, all those affected emissions units are exempt from the state toxics rule (9VAC5-80-1105.F) and are not subject to Article 6 for toxic pollutant emissions.

Emissions from the fuel storage tanks are below the exemption levels in 9VAC5-60-300 et seq (9VAC5-60, Article 5), so the tanks are not subject to Article 6 permitting as per 9VAC5-80-1105.E.

D. 9VAC5 Chapter 50, Part II, Article 5 - NSPS Requirements:

1. Subpart Dc: The 18.8 MMBtu/hr fuel gas heater will be 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. As a natural gas-fired unit, records of the amount of fuel burned in that unit each calendar month must be kept [40 CFR 60.48c(g)(2)].
2. Subpart IIII: The seven 4,694 hp black start generators will be subject to NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. As emergency units the engines will be certified to meet 40 CFR 1039 Tier 2 standards.
3. Subpart Kc – The fuel oil storage tanks proposed for the CERC equipment will not be subject to NSPS Subpart Kc Standards of Performance for Volatile Organic Liquid Storage Vessels. The 12-million-gallon fuel oil tank contains petroleum liquid with a maximum true vapor pressure of less than 3.4 kPA and the seven 3,500-gallon fuel storage tanks for the black start generators are less than 20,000 gallons.
4. Subpart KKKK: The SCCTs will be 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 15 ppm @ 15% O_2 or 0.43 lb/MWh when burning natural gas and 42 ppm @ 15% O_2 or 1.3 lb/MWh when firing oil. If the combustion turbines operate in partial load (< 75% of peak) or at temperature less than 0°F, a NOx limit of 96 ppm at 15% O_2 or 4.7 lb/MWh will apply. Compliance will be based on the arithmetic average of hourly applicable NOx emissions based on a 4-hour rolling average (as measured by CEMS).

   The source proposes the use of low NO_x burners and SCR to control NO_x emissions to levels below the NSPS Subpart KKKK standards.

   NSPS Subpart KKKK also requires the source to meet an SO_2 emission limit of 0.9 lb/MWh gross output from fuel burning or not burn any fuel that contains the total potential sulfur emissions in excess of 0.06 lb SO_2/MMBtu heat input. These will be achieved by combusting natural gas with a sulfur content of no more than 0.4 gr/100 dscf (average annual) or fuel oil with a sulfur content of 0.0015 percent by weight. Compliance will be based on documentation of the fuel quality characteristics provided by the fuel supplier.

   Turbines regulated under NSPS Subpart KKKK are not subject to NSPS Subpart GG.

   Note: In December 2024, EPA proposed tighter NOx limits in NSPS Subpart KKKK (to be known as subpart KKKKa) which could be promulgated by the end of 2025. The controls proposed for this source will meet those tighter limits (i.e., new standards when operating above 70% of the base load of 3 ppm when firing natural gas and 5 ppm when firing fuel other than natural gas).
5. Subpart TTTTa Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units (May 2024): DEQ has not requested delegation

to enforce this regulation so no requirements will be included in the PSD NSR permit, but the facility will need to demonstrate compliance with the standards in this subpart to EPA's satisfaction.

E. 9VAC5 Chapter 60, Part II, Article 1 – NESHAP Requirements

None of the CERC units are subject to a NESHAP.

F. 9VAC5 Chapter 60, Part II, Article 2 - MACT Requirements:

The following standards apply to emission units at this facility, which is a major source of Hazardous Air Pollutants (HAP). DEQ retains authority to enforce these requirements for major sources of HAP. However, EPA only recognizes federally-enforceable limits on Hazardous Air Pollutants in Federal Operating Permits (9VAC5-80, Article 3) and federally-approved State Operating Permits (9VAC5-80, Article 5). Therefore, no MACT requirements will be included in this Article 8 PSD NSR permit (but will be included in the facility's Article 3 combined Title IV/Title V Operating Permit).

1. Subpart YYYY: The SCCTs are subject to MACT Subpart YYYY National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. The turbines are affected sources according to 40 CFR 63.6090(a)(2): lean, pre-mix, gas-fired or diffusion flame gas-fired combustion turbines starting up after March 9, 2022. The units must comply with the emission limitations and operating limitations in Table 1 and Table 2 of that subpart according to 40 CFR 63.6100. Initial performance tests and compliance demonstrations must be conducted as per Table 4 using methods in Table 5, and annually as per Table 3 of this subpart (for formaldehyde).

2. Subpart ZZZZ: The seven 4,694 hp black start engine-generators are subject to MACT Subpart ZZZZ National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE) as a major source of HAP.

   The black start engines are stationary RICE to be operated at a major source of HAP (40 CFR 63.6585) and are affected new stationary RICE [40 CFR 63.6590(a)(2)] but are considered "Stationary RICE subject to limited requirements" as emergency stationary RICE, with a site rating of more than 500 bhp, located at a major source of HAP emissions [40 CFR 63.6590(b)(1)(i)]. As such, they are only subject to the initial notification requirement. DEQ is delegated to enforce this federal regulation for any source subject to Title V permitting.

3. Subpart DDDDD: The fuel gas heater is considered a process heater for applicability to this subpart. The fuel gas heater, therefore, is subject to this subpart. A new gas-fired unit greater than 10 MMBtu/hr would be required to conduct an annual tune-up.

G. State Only Enforceable (SOE) Requirements (9VAC5-80-1120.F)

The facility is not subject to any SOE requirements. All the conditions in the permit are federally enforceable.

H. 9VAC5 Chapter 40, Part II, Existing Sources – Emission Standards

Units that triggered applicability to PSD permitting or minor NSR permitting would have BACT permit limits that are more stringent than the Chapter 40 rules that might apply to that equipment.

IV. Best Available Control Technology (BACT)

A. 9VAC5-50-280 and 9VAC5-80-1705 PSD BACT:

PSD BACT review applies to each pollutant that had a significant net emission increase. This project triggered PSD BACT for PM2.5, CO, VOC, and CO_2e (see Table 2).

The determination of PSD BACT usually involves a top-down method that includes the following five steps:

Step 1 – Identify all possible available control options;

Step 2 – Eliminate technically infeasible control options;

Step 3 – Rank the remaining control options by control effectiveness;

Step 4 – Evaluate most effective and achievable emission limits and the effects on economics, energy, and environment

Step 5 – Select BACT.

Following the top-down approach, all "available" control options are identified for PM2.5, CO, VOC and CO_2e emitted from the SCCTs, emergency engines, fuel gas heater, circuit breakers, fuel tanks, and fugitive leaks from gas piping components. The options that are technically infeasible are eliminated from further considerations and the remaining options are ranked by control effectiveness. The top option is then evaluated on the basis of the associated economic, energy, and environmental impacts. If the top option is eliminated based on any of these criteria, the next most stringent technology is evaluated. This process is continued until a control option is identified as BACT.

BACT is determined based on the proposed project. BACT analysis does not require a consideration of alternatives that would result in a redefinition of the source. See Section 5.1 of the permit application for details.

1. **Greenhouse gases:** Carbon dioxide (CO_2) is formed during oxidation of carbon-based organic material (i.e, during cellular respiration in living organisms, decomposition of organic matter, and combustion of carbon-based fuels). This is because carbon-containing molecules, in the presence of oxygen, will release CO_2 and water vapor.

   Methane (CH_4) is naturally formed during decomposition in low-oxygen environments. It is also the main component of natural gas. Natural gas was formed when ancient marine plants and microorganisms were buried by sediment and decomposed without much oxygen. Methane breaks down into CO_2 and water when combusted. Unburned methane in the exhaust of fuel-burning equipment accounts for less than 0.2% of the total greenhouse gases from fuel combustion.

Nitrous oxide (N_2O) is primarily released into the atmosphere from nitrogen fertilizers (organic, synthetic, manure, and burning of agricultural waste). However, it is also released in small amounts from fuel combustion.

Sulfur hexafluoride (SF_6) is a stable, non-combustible, synthetic compound used in the manufacturing of electronic components. It is non-toxic but it is a very potent greenhouse gas. It is primarily used as a superior insulator for high-voltage electrical circuit breakers and is not usually released, with proper care.

Collectively, these greenhouse gases, when multiplied by the global warming potential (GWP) for each, are known as carbon dioxide equivalents (CO_2e). The combined CO_2e emissions from the proposed project trigger PSD permitting so BACT must be determined for CO_2e.

a. <u>Simple Cycle Combustion Turbines (SCCTs) (four 250 MWe dual fuel units)</u>

i. Available Control Options (Step 1):

- Carbon capture and sequestration (CCS) is an available technology. Exhaust gases containing CO_2e from the turbines would be captured and concentrated and transported to a location suitable for storage or reuse. The sequestration method first proposed by early studies involved the captured CO_2 be injected underground, usually deep in an existing geologic reservoir (limiting the technology to certain geologic regions of the US). More recently, other post-combustion CCS technologies are in current development (pilot plant studies) that could be used on a combustion turbine. Carbon capture, utilization and storage (CCU or CCUS) is the use of reagents, solvents, or sorbents (with or without catalyst) to remove (scrub) CO_2 from the flue gas. The solvent+CO_2 is then regenerated, releasing the CO_2 for compression and then storage in a vessel (to be transported by pipeline or vehicle for future use) and returning the scrubbing solvent to be regenerated for re-use.
- Good combustion practices (GCPs) encompass proper operation of the turbines, as designed and as recommended by the turbine manufacturer.
- Efficient power generation can minimize CO_2e emissions (by minimizing unburned methane in the fuel).
- Using lower carbon fuel. Natural gas combustion creates less CO_2 than combusting oil or coal. Restrictions on oil throughput will limit emissions of CO_2. Blending natural gas with hydrogen reduces the amount of CO_2 produced.

ii. Technically feasible control options (Step 2):

- CCS - Carbon capture technology is technologically feasible for combustion turbines.
- GCPs are feasible for these units.
- Efficient power generation is technically feasible for this project. Modern SCCTs can ramp up to full power quickly but can operate at lower loads and still achieve compliance with most emission standards. Modern SCCTs are estimated to be about 32-40% efficient at standard conditions.
- Low carbon fuels are technically feasible and available for this project.

iii. Rank effectiveness of GHG control options (Step 3) remaining from Step 2:

The technically feasible controls listed in Step 2, are ranked by effectiveness as follows:

- CCS/CCU would be most effective (90% for coal plants, somewhat less for fuel oil combustion, and much less for a natural gas-fired turbine with relatively low concentration of CO_2 in the exhaust). Efficiency is reduced further during non-steady state operation.
- GCPs, low carbon fuel, and the efficiency-boosting design features minimize CO_2.

iv. Evaluate the most effective and achievable emission strategies from Step 3 and the effects on economics, energy, and the environment (Step 4):

Of the effective technologies mentioned in Step 3 above - namely GCPs, efficient power generation, and the use of low carbon fuels - there are no direct economic, energy, or environmental impacts associated with these control technologies. One slight drawback in the use of hydrogen blending in natural gas is that this technique to lower CO_2 raises the temperature in the combustion chamber, increasing emissions of NOx. This can be overcome with NOx controls, however (like SCR and inlet fogging/cooling – see Section IV.B.1.a).

CCS/CCU technology reduces CO_2 very well and is in actual use at a handful of coal-fired power plants, petroleum refineries and small (grant-funded) pilot-scale power plants, however several issues arise for CCS on a simple-cycle turbine. The added technology for CCS/CCU can reduce the efficiency of a power plant by 10-40%. CCS/CCU would involve the addition of adsorbers, chillers, compressors, heaters, and a transport system. A SCCT operates very intermittently, albeit sometimes for several hours or even days, but not constantly. Construction of a CCS system would not be economically feasible.

v. GHG BACT Selection (Step 5)

A search of the RBLC for SCCTs that have permits issued in the last 10 years with GHG/CO_2e limits and that have started operation (compliance with BACT limit can be demonstrated), shows GHG BACT to be a combination of work practices:

Table 4 - GHG BACT for SCCTs

Facility	Permit date	Equipment	BACT	GHG Limit
Elk EC, TX	May 20, 2015	Three 202 MW SCCT	Energy efficiency, good design, & combustion practices	1,304 lb CO_2/MWh (*2023 data: 1,163 lb/MWh net*)
Lauderdale Plant, FL	August 25, 2015	Five 241 MW SCCT (Unit 6)	Use of natural gas with restricted use of #2 fuel oil (3390 hrs/year/CT with 500 hrs/yr on #2 fuel oil)	1,372 lb/MWh (weighted average for all turbines for 36 months) and 1,871 lb/MWh (individual 36-month average) (*2023 12-month total 1,340 lb/MWh*)

Facility	Permit date	Equipment	BACT	GHG Limit
Ft Meyers Plant, FL	September 10, 2015	Two nominal 250 MW SCCT (nominal heat input of 2,262.4 MMBtu on natural gas and 2,353.7 MMBtu on #2 oil) replacement units.	Use of low-emitting fuel and efficient turbine operation (3390 hrs/year average/CT including an aggregate average of 2,353,700 MMBtu/yr on #2 fuel oil).	1,374 lb/MWh on natural gas and 1,874 lb/MWh on #2 oil (combined 12-month rolling average for the first 36 months of operation, then individual 36-month average) for all operation.(*cannot determine compliance using 2023 data for entire facility*)
PSEG Fossil Sewaren, NJ	March 10, 2016	One dual fuel 345 MW CCCT (Unit 7) that can operate w/o DB	Use of natural gas and restricted diesel fuel.	163 lb/MMBtu when burning FO, 117 lb/MMBtu when burning NG; 888 lb/MWh per 12 month operation, including steam turbine power generation.
APS Ocotilla, AZ	March 22, 2016	Five 104 MW NG CTs	GCPs	1,460 lb/MWh gross, normal operation (*2023 data, 1,126 lb/MWh includes power from two older CTs*)
Invenergy Nelson plant expansion, IL	September 27, 2016	Two 190 MW SCCTs	Turbine-generator design and proper operation	Average annual GHG limit based on 1367 lb/MWh gross on natural gas and 1934 lb/MW gross on #2 fuel oil.
Doswell EC, VA	October 4, 2016	Two SCCT, 187 MWh (1,961 MMBtu/hr) on natural gas (4,372,500 MMBtu/yr)	Low carbon fuel, high-efficiency design, GCPs	1,361 lb/MWh annual average and 11,627 Btu/kWh gross HHV. (*2024 data less than 1,274 lb/MWh and less than 10,721 Btu/kWh*)
Montpelier, IN	January 6, 2017	Four 60 MW NG CTs with ULSD backup (500 hours)	NG & GCPs	118 lb/MMBtu (NG); 162 lb/MMBtu (#2 fuel oil) (*2023 data, NG only, 113 lb/MMBtu*)
Cameron LNG, LA	February 17, 2017	Nine gas turbines (1069 MMBtu/hr ea)	NG & GCPs, use of high thermal efficiency turbines	120 lb/MMBtu (50 kg/GJ) (NSPS TTTT)
Mustang, TX	August 16, 2017	three SCCTs. Increase Unit 6 SCCT to 3,000 hrs/yr.	Pipeline quality NG and GCPs	120 lb/MMBtu (*2023 data 119 lb/MMBtu*)
Washington Parish (Entergy) EC, LA	May 23, 2018 (May 24, 2023 to add “Auto Tune” technology)	Two NG 200 MW SCCT, (2201 MMBtu/hr ea), (7000 hrs/yr)	Facility-wide energy efficiency measures, i.e., improved combustion measures and use of pipeline quality NG	120 lb/MMBtu; 50 kg/GJ (*2023 data 104 lb/MMBtu*)
Calcasieu Pass LNG, LA	September 21, 2018	One 263 MMBtu/hr Aeroderivative SCCT	Low carbon fuel, GCPs, good operation and maintenance practices, insulation.	-
Ector Co, TX	August 17, 2020	Increase hours of operation for two 179.4 MW SCCTs firing NG	Best management practices and GCPs, clean fuel	1,514 lb/MWh (*2023 data 1,388 lb/MWh*)
Colbert CT Plant, AL	September 21, 2021	Three 229 MW SCCTs firing NG	Energy efficiency design, GCPs, NG fuel.	120 lb/MMBtu (NSPS TTTT) (*2023 data 119 lb/MMBtu*)

Facility	Permit date	Equipment	BACT	GHG Limit
LBWL-Delta Energy Park, MI	December 21, 2018; January 7, 2021; & December 20, 2022	One nominal 667 MMBtu/hr NG fired SCCT.	Low carbon fuel (pipeline quality natural gas), GCPs, and energy efficiency measures.	-

- The turbines that are proposed for this project will be installed with design features that can boost efficiency and minimize CO_2e emissions:
  - Evaporative inlet air cooling/inlet fogging
  - Periodic tuning
  - Insulation to reduce heat loss
  - Using sophisticated instrumentation to manage CT operation.
- Additionally, GCPs and low carbon fuel (natural gas with or without a blend of hydrogen, and restrictions on the annual amount of fuel oil that can be combusted) will be required.

DEQ concludes that BACT for GHG will be efficient turbine design and operation, documented GCPs, and the use of low-carbon fuel to achieve an emission factor of 120 lb/MMBtu for natural gas and a factor of 160 lb/MMBtu for fuel oil combustion. Compliance will be based on an initial stack test for CO_2 and the emissions factors for CH_4 and N_2O found in the Mandatory Greenhouse Gas Reporting in 40 CFR, Chapter I, Subchapter C, Part 98, Table C-2 and the global warming potentials (GWP) for those pollutants in Subpart A, Table A-1.

b. <u>Fuel Gas Heater (18.8 MMBtu/hr)</u>

A search of the RBLC for fuel gas heaters/boilers, that have permits issued in the last 10 years with GHG/CO_2e limits, and that have started operation (BACT limit is demonstrated), produced the following, showing GHG BACT to be a combination of work practices:

Table 5 - GHG BACT for natural gas-fired fuel gas heater

Facility	Permit date	Equipment	BACT	GHG Limit
Grayling Particleboard, MI	August 26, 2016 & December 18, 2020	Thermal oil heater 38 MMBtu/hr	GCPs, good maintenance practices, NG fuel (CCS not economically feasible at $102/ton for entire facility)	-
Invenergy Nelson plant expansion, IL	September 27, 2016	15 MMBtu/hr NG fuel heater	-	-
Holland Board of PW, MI	December 5, 2016	Fuel heater (dew point heater)	GCPs	-
TopChem Pollock, LA	December 20, 2016	20 MMBtu/hr NG Start-up heater	Pipeline NG, limit on operation to 148 hrs/yr	52.21 kg/MMBtu, 0.001 kg/MMBtu CH_4; 0.0001 kg/MMBtu N_2O
Indeck-Niles, MI	January 4, 2017 & November 26, 2019	Two fuel pre-heaters (dew point heaters)	Energy efficiency measure and NG fuel	-

Facility	Permit date	Equipment	BACT	GHG Limit
Guernsey PS, OH	October 23, 2017	Two fuel gas heaters, 15.0 MMBtu/hr	NG fuel	-
Nucor Steel Berkley, SC	May 2, 2018	Two 4.75 MMBtu/hr cleaning heaters	NG, efficient combustion technology, GCPs	
Belle River CCT Plant, MI	July 16, 2018	Two fuel gas heaters, 20.8 MMBtu/hr and 3.8 MMBtu/hr	NG fuel	-
CPV Three Rivers, IL	July 30, 2018	12.8 MMBtu/hr NG fuel heater	GCPs	-
Arkema Beaumont, TX	August 24, 2018	Heaters	Low carbon fuel and GCPs	-
Green Bay Pkg, WI	September 6, 2018	40 MMBtu space heaters	GCPs, NG, LNB,	-
Jackson EC, IL	December 31, 2018	13 MMBtu/hr fuel heater	GCPs	-
Michigan State Univ, MI	May 22, 2019	Two fuel gas heaters, 25 MMBtu/hr each	Low carbon fuel, energy efficiency measures, preventive maintenance as per mfr recommendations (CCS not economically feasible)	-
Thomas Township, MI	August 21, 2019	Two fuel gas preheaters, 7 MMBtu/hr each	Energy efficiency	-
Green Bay Pkg, WI	December 10, 2019	8.5 MMBtu combined space heaters	NG fuel, 90% avg thermal efficiency	-
Orange Polyethylene Plant, TX	April 23, 2020	Heaters	GCPs, clean fuel, proper design	-
Nemadji Trail EC, WI	September 1, 2020	Two 10 MMBtu/hr heaters	LNB, NG fuel, operate and maintain as per mfr recommendations	-
Nucor Steel Gallatin, KY	April 19, 2021	Two 14.5 indirect-fired heaters	Good combustion	
Colbert CT Plant, Al	September 21, 2021	Three 10 MMBtu/hr gas heaters firing NG	-	117.1 lb/MMBtu*
Orange Co Advanced PS, TX	March 3, 2023	Water bath heater	GCPs	-
Cameron LNG, LA	September 19, 2023	Three hot oil heaters	Use of low carbon fuel and GCPs	-
Wabash Valley Resources, IN	January 11, 2024	Dewpoint heater	GCPs	117 lb/MMBtu*

*The factor of 117.1 lb of CO_2e/MMBtu of natural gas combusted comes from 40 CFR Part 98 Mandatory Greenhouse Gas Reporting, Chapter 1, Subchapter C – General Stationary Fuel Combustion Sources, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel (53.06 kg of CO_2/MMBtu when combusting natural gas) and Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel (0.001 kg CH_4/MMBtu and 0.0001 kg N_2O/MMBtu), converted to pounds and multiplied by the GWP of methane and nitrous oxide.

Add-on controls to reduce emissions of CO_2e from this smaller fuel-burning unit are not economically or technically feasible or available. DEQ determines BACT for this unit will be the use of low carbon fuel and GCPs.

c. Emergency black start generators (3500 kW each)

A RBLC search for GHG/CO_2e BACT for diesel emergency generators produced hundreds of results over the past 10 years. Reducing the timeframe to the most-recent five years (2020 to present) produced over 100 results. A review of those results did not find any add-on controls for GHG. BACT was determined to be a combination of the following:

- GCPs, good operating practices (plan), good design practices
- Limit on operation (hrs/year)
- Energy efficiency measures, i.e., improved combustion, insulation, minimized air infiltration
- Few emission factors were listed as BACT, but the ones that were listed seemed to reflect the 163.6 lb/MMBtu factor found in the GHG Reporting rule for CO_2 from petroleum liquid combustion.

These limitations are available, feasible, and effective and do not create economic or environmental consequences.

Dominion has proposed GHG BACT for the seven black start diesel engine-generators to be GCPs. Additionally, the proposed engines will operate with automated combustion controls and will be limited to 500 hours of operation.

DEQ concurs that GCPs, including operating the units as designed, according to manufacturer's recommendations, as well as limits on annual operation, is BACT for the black start engine.

d. Fugitive methane emissions

Purged natural gas during maintenance and pipe inspections could release up to 2 tons of CH_4 and leaking piping components could contribute another 3 tons of CH_4 per year (equivalent to 155 tons of CO_2e total). Control techniques consist primarily of leak detection and repair (LDAR), as well as prevention of leakage and minimization of methane releases. Prevention includes minimizing venting, making sure connections are secure, and performing routine maintenance on the components. Leak detection and repair includes inspecting and testing to find leaks and then repairing them. These methods are all technically feasible and available. An audible/visual/olfactory (AVO) inspection can be quite effective in detecting leaks, when performed by trained plant personnel. Odorizers (mercaptans) are not always added to natural gas that is going to a power station, due to the rigid sulfur content requirements in the permit. However, hydrocarbon has enough odor that it can be detected through AVO inspections.

There are other techniques for detecting leaks of gas or volatile liquids (i.e., instrumentation like sensors or optical imaging), that can cost several thousand dollars but could save the cost of wasted natural gas. Listing all of the monitoring techniques in the permit would not be constructive.

A review of the RBLC results in AVO (and/or LDAR) being the only required "control" for fugitive leaks from most facilities. Therefore, BACT for fugitive emissions of methane from gas piping components and maintenance activities shall be to use best management practices (for example, directed inspection and maintenance) to prevent, detect and repair natural gas releases. The permittee must develop a fugitive emission monitoring (FEM) plan, keep the plan available for inspection on site, and keep records of all monitoring results and actions taken.

e. Electrical Breakers

The electrical circuit breakers contain SF_6. 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, SF_6 circuit breakers have superior insulating and arc-quenching capabilities. The oil and air-blast units are also larger than the SF_6 units, generate more noise, and the dielectric oil is flammable and 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.[1] Emissions from the circuit breakers proposed for this project were based on a maximum leakage rate of 0.5 percent over the course of a year. RBLC results for circuit breakers are few but overwhelmingly "enclosed pressure type breaker and leak detection, with low pressure alarm" is indicated as BACT. Dominion has proposed "enclosed-pressure circuit breakers with leak detection" for circuit breakers containing SF_6, (and non-SF_6 circuit breakers for circuits under 145 kV). DEQ concurs that BACT for the circuit breakers will be to minimize SF_6 leakage by using an enclosed-pressure circuit breaker with no more than a 0.5 percent annual leakage rate and a leak detection system.

2. **Carbon Monoxide Control** - Carbon monoxide emissions are formed in the exhaust of a fuel-burning unit as a result of incomplete combustion of the fuel. 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. Available Control Technologies (Step 1)

- 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

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1 *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.

catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM10, PM2.5, carbon dioxide, and H_2SO_4.

CO oxidation catalyst operates in a relatively narrow temperature range. A catalytic oxidizer optimum operating temperature is in the range of 700°F to 1100°F (the exhaust temperature of the proposed SCCTs are estimated to be around 800°). 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 for evenly-distributed gas flow across the catalyst and proper operating temperature. Operation at partial load, or during startup/shutdown results in 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 costliest 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.

- GCPs, consisting primarily of controlled fuel/air mixing and adequate temperature and gas residence time, are used to minimize the formation of CO. GCPs are technically feasible for this project.
- SCONOx™ is used for NOx control but it also reduces CO by oxidizing the CO to CO_2. The technology is a combination of catalytic conversion of CO with an absorption and regeneration process without the use of ammonia reagent. The SCONOx™ operating temperature is in the range of 300°F to 700°F. This would require the exhaust temperature of the turbine to be reduced by a cooling system.
- Non-selective Catalytic Reduction (NSCR) is also primarily used for NOx control. It uses a noble metal catalyst reaction to reduce CO to CO_2. Operating temperature is between 700°F and 1500°F. NSCR requires low excess oxygen in the exhaust gas to be effective. Therefore, the NSCR is most effective with rich-burn gas-fired units operating with carefully controlled air to fuel ratios, close to stoichiometric conditions.

ii. Technically feasible control options (Step 2):

- The cost of installation and operation of SCONOx™ is high. It requires supplemental resources (steam, fuel, compressed air, electricity) creating additional complexities. This technology has not been demonstrated on large combustion turbines (greater than 40 MW). This technology is not feasible for this project.
- As mentioned in Step 1 above, NSCR is limited to operations with rich-burn units with an air to fuel ratio controller and an excess air concentration below 1% (the SCCT excess air concentration is around 15%). Therefore, this technology is not feasible for this project.
- Oxidation catalyst is demonstrated and feasible for this project.
- GCPs are demonstrated and feasible for this project.

iii. Rank effectiveness of CO control options (Step 3) remaining from Step 2

The most effective technologies that are available for a large, dual fuel-fired, simple-cycle power generating facility for controlling CO are:

- Oxidation catalyst as a post-combustion treatment (control efficiency about 86% when firing #2 oil and 69% when firing natural gas) can reduce CO to 2.0 ppmvd @15% O_2 for either fuel.
- GCPs to control the formation of CO has no quantified efficiency.

iv. Evaluate most effective and achievable emission strategies for CO from Step 3 and the effects on economics, energy, and the environment (Step 4):

Oxidation catalyst and GCPs can be used together to reduce CO emissions. There are no effects on economy. As mentioned, there may be some back pressure and collateral increases in emissions of PM10, PM2.5, carbon dioxide, and H_2SO_4 from these technologies but these would not outweigh the benefits of CO reduction.

v. Select BACT for CO (Step 5)

Dominion has proposed a combination of oxidation catalyst and GCPs.

The CO limits in the most recent BACT determinations in the RBLC are as follows:

Table 6 CO RBLC Turbine Limits

Facility	Permit date	Equipment	BACT	CO Limit
Elk EC, TX	May 20, 2015	Three 202 MW SCCT (4,572 hrs/yr ea)	GCPs, limited hours of operation combustion practices	9 ppmvd @ 15% O_2 on a 3-hr avg, normal operation
Cameron LNG, LA	March 3, 2016	Six 1,069 MMBtu/hr gas turbines firing NG	NG and GCPs	15 ppmvd @ 15% O_2
PSEG Fossil Sewaren, NJ	March 10, 2016	One 345 MW dual fuel CT that can operate without DB (Unit 7)	Oxidation catalyst and GCPs	6 ppmvd @ 15% O_2 1-hr avg.
Ocotillo Power, AZ	March 22, 2016	Five 104 MW SCCTs firing NG	Oxidation catalyst and GCPs	6 ppmvd @ 15% O_2 (13.5 lb/hr) during normal operation, 1-hr avg. 69.2 lb/hr during SU/SD

Facility	Permit date	Equipment	BACT	CO Limit
Bayonne EC, NJ	August 26, 2016, revised March 2023	Eight 66 MW SCCTs firing NG (and FO 720 hrs/yr), capable of operating as black start units	Oxidation catalyst (presumptive BACT, not PSD)	5 ppmvd @ 15% O_2 on either fuel on a 3-hr rolling avg (CEMS)
Doswell EC, VA	October 4, 2016	Two 1961 MMBtu/hr SCCT firing NG	Clean fuel NG, GCPs	4 ppmvd@15% O_2 1-hr avg.
Montpelier EC, IN	January 6, 2017	Eight dual fuel 25 MW (270.9 MMBtu/hr) SCCT, powering four generators, 4555 hrs/yr	NG as fuel (limit on fuel oil to 500 hrs), GCPs	0.2 lb/MMBtu on NG 0.3 lb/MMBtu on FO
Lauderdale Plant, FL (Unit 6)	August 14, 2017 revision	Five 241 MW net dual fuel SCCTs (3,390 hrs per turbine 12-mo average)	GCPs	4 ppmvd @ 15% O_2 (9 ppmvd on FO) three 1-hr test runs
Washington Parish EC, LA	May 23, 2018	Two 207 MW SCCTs firing NG (7000 hrs/yr)	GCPs and NG fuel	6 ppmvd @ 15% O_2 annual avg
LBWL Erickson Sta, MI	January 7, 2021 & January 11, 2022	667 MMBtu/hr NG fired SCCT	DLN and GCPs	9 lb/hr except during SU/SD
TVA Colbert CT, AL	September 21, 2021	Three 229 MW (2,254 MMBtu/hr) SCCT firing NG	GCPs and DLN	9 ppmvd @ 15% O_2 3-hr rolling avg (CEMS)
TVA Johnsonville, TN	August 31, 2022	Ten 55.5 MW (465.8 MMBtu/hr) SCCTs firing NG	Oxidation catalyst, GCPs	5 ppmvd @ 15% O_2 4-hr rolling avg (CEMS)

Dominion has proposed CO limits for the CERC SCCTs at 2.0 ppmvd @ 15% O_2, using oxidation catalyst and GCPs for both natural gas and fuel oil combustion. Therefore, the proposed limit is much more stringent than previous BACT determinations for a SCCT and more typical for BACT for a CCCT with oxidation catalyst.

The averaging time for the limit is important, however. The CO will be monitored with CEMS (see Section IX). Many CCCTs are only allowed a 1-hour rolling averaging time to show compliance with the 2.0 ppmvd limit since, when operating, they are usually at full power for long periods of time and emissions should be fairly constant (and low). SCCTs, however, are expected to ramp up in a few minutes, run for a few hours, then shut down. Due to the very stringent CO limit proposed for the CERC, DEQ allowed for a longer averaging time to account for the possibility of CO emission variability that could occur.

DEQ concludes that the proposed oxidation catalyst control, along with GCPs, constitute BACT for CO from the CTs as follows:

- 2.0 ppmvd @ 15% O_2, measured by CEMS on a 4-hour rolling average, while combusting either #2 fuel oil or natural gas.

b. Fuel Gas Heater (18.8 MMBtu/hr on natural gas)

i. List of control technologies (Step 1)

- GCPs

- Oxidation catalyst (add on)

ii. Eliminate technically infeasible options of CO Control (Step 2)

- GCPs are feasible and available for this unit
- Oxidation catalyst is feasible and available for this unit

iii. Rank effectiveness of CO control options (Step 3) remaining from Step 2

- GCPs can result in emissions from the units in the range of 0.08 lb/MMBtu to 0.03 lb/MMBtu.
- Oxidation catalyst could reduce emissions further to about 0.006 lb/MMBtu

iv. Evaluate most effective and achievable emission strategies for CO from Step 3 and the effects on economics, energy, and the environment (Step 4):

- Of the technologies mentioned in Step 3 above, the use of oxidation catalyst would emit less carbon monoxide than good combustion practices alone. However, this add-on control may cause back pressure in the exhaust flow, increasing the fuel use and decreasing the combustion efficiency. Additionally, the difference in CO emissions between installation of an oxidation catalyst and good combustion practices alone is only 2.5 tons (3.0 tons/year from GCPs and 0.5 tons/year for oxidation catalyst). An oxidation catalyst is not economically feasible for this unit and there would be some impact on energy efficiency for this fuel gas heater.
- There are no negative economic, energy, or environmental impacts associated with the proposed GCPs.

v. CO BACT selection for the fuel gas heater (Step 5)

A search of the RBLC for BACT for small, natural gas-fired fuel gas heaters/boilers determines that GCPs, proper burner design, and natural gas fuel are the selected methods of control. These work practices result in CO emissions ranging from 0.084 lb/MMBtu to 0.037 lb/MMBtu for similar sized units burning natural gas. Dominion proposed a rate of 0.037 lb/MMBtu (50 ppmvd; 0.35 lb/hr) using GCPs.

DEQ concurs that good combustion practices and proper burner design is BACT for CO from the 18.8 MMBtu/hr, natural gas-fired fuel gas heater.

c. <u>Black Start Generators (3500 kW diesel units)</u>

i. List CO control technologies for large, emergency RICE (Step 1).

- NSCR
- Oxidation catalyst
- GCPs (efficient engine design, clean fuel, limit hours of operation)

ii. Technically feasible control options (Step 2)

- NSCR is most effective on gasoline engines. It is not technically feasible for a lean-burn diesel RICE.
- Oxidation catalyst is technically feasible for a diesel RICE
- GCPs are technically feasible

iii. Rank effectiveness of CO control options (Step 3) remaining from Step 2

- Oxidation catalyst can reduce CO emissions by about 60-90% and would also minimize VOC emissions.
- GCPs minimize emissions but do not reduce emissions. Engine manufacturers design such large engines to meet the latest NSPS IIII standards for CO emissions from emergency-use engines without add-on controls.

iv. Evaluate most effective and achievable emission strategies for CO from Step 3 and the effects on economics, energy, and the environment (Step 4)

- Oxidation catalyst would be more cost-effective on a combustion unit that operated for longer periods and produced more emissions. The black start engine-generators are limited to only 500 hours of operation per year. Even without add-on controls, these units are certified to meet the Tier 2/Tier 4 (NSPS Subpart IIII) CO standard of 3.5 g/kWh (or 2.6 g/hp-hr).
- GCPs are also effective at minimizing CO emissions and do not result in negative effects on economy, energy or the environment.

v. Selection of BACT for CO from the emergency engines (Step 5)

A RBLC search of large diesel engines permitted since 2020 returned about 58 entries. Of those, 22 listed a BACT limit of 2.6 g/bhp-hr and 21 listed a limit of 3.5 g/kW-hr (which are the Tier 2 and Tier 4 standards for emergency and non-emergency engines from NSPS Subpart IIII). Compliance with NSPS Subpart IIII (or purchasing a certified engine meeting the NSPS standard) was also listed as BACT 32 times. Two entries required oxidation catalyst but, in one of those cases, the CO limit was still 2.6 g/kW-hr. In the other entry requiring oxidation catalyst for a Tier 4, 4,060 hp diesel engine at a gas treatment plant in Alaska, the limit was 3.3 g/hp-hr but that was indicated to be the not-to-exceed limit which would be 25% higher than the NSPS standard. Only one entry (with numerical emission limits) was lower than the NSPS standard. The Hybar LLC Rebar Plant in Arkansas had a CO limit for four 2700 kW diesel emergency generators listed at 0.9 g/bhp-hr. BACT was described as "good operating practices, limited hours of operation, compliance with NSPS Subpart IIII" and oxidation catalyst was not required. Examination of the permit and the associated statement of basis for that facility confirmed the limit but could not find an explanation of the basis of that low limit.

Since the manufacturer of the black start engine-generators for the proposed project has not yet been selected, no spec sheet can be reviewed. However, a new engine (2025 or later) would be very efficient and would be designed to meet Tier 2 standards at a minimum. Therefore, DEQ accepts GCPs (efficient engine design, clean fuel, limit hours of operation) and requiring the purchase of engines that are certified to meet the CO emission standards of the EPA NSPS, Subpart IIII, standard for emergency engines as BACT for CO from the black start engines.

3. 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 available VOC controls for combustion turbines (Step 1)

- Oxidation catalyst (controls CO as well).
- GCPs (efficient engine design, controlled fuel/air mixing and adequate temperature and gas residence time, clean fuel, limit hours of operation).

ii. Technically feasible control options (Step 2)

- An oxidation catalyst is considered to be available and technically feasible for application to this project during normal and steady-state operation.
- GCPs are available and technically feasible.

iii. Rank effectiveness of VOC control options (Step 3) remaining from Step 2

- Oxidation catalyst has already been selected as BACT for CO removal so it will be installed on the combustion turbines regardless of its performance at VOC removal. The efficiency of an oxidation catalyst in removing VOC is dependent on how much VOC is present in the exhaust stream prior to the control, and the temperature of the exhaust gas. Uncontrolled VOC emissions from the turbines (steady state operation) while combusting fuel oil are expected to be about 9.3 lbs/hr. With oxidation catalyst, VOC emissions are reduced to 6.7 lbs/hour (almost 30% reduction). For natural gas combustion, uncontrolled emissions are 3.6 lbs/hr and controlled emissions are around 3.2 lbs/hr (about 10% reduction). Oxidation catalyst is not effective in removing VOC during startup and shutdown due to lower concentration and lower temperatures during those scenarios (see Section IV.A.5).
- GCPs minimize the formation of VOC emissions

iv. Evaluate most effective and achievable emission strategies for VOC from Step 3 and the effects on economics, energy, and the environment (Step 4):

- The benefit of VOC control in addition to CO control makes oxidation catalyst economically feasible for both pollutants. There is no energy or environmental effect for installation of oxidation catalyst on dual fuel SCCTs
- GCPs are effective and do not create economic, energy, or environmental effects.

v. Selection of VOC BACT for combustion (Step 4)

Dominion has proposed a combination of control options for VOC: oxidation catalyst and good combustion practices.

The VOC limits in the most recent PSD BACT (and some LAER) determinations in the RBLC are as follows:

Table 7 - VOC RBLC Turbine Limits

Facility	Permit date	Equipment	BACT	VOC Limit
Elk EC, TX	May 20, 2015	Three 202 MW SCCT (4,572 hrs/yr ea)	GCPs	2 ppmvd @15% O_2

Cameron LNG, LA	March 3, 2016	Six 1,069 MMBtu/hr gas turbines firing NG	GCPs and NG fuel	1.6 ppmvd @15% O_2 3-hr avg
Ocotillo Power, AZ	March 22, 2016	Five 104 MW SCCTs firing NG	Oxidation catalyst	2 ppmvd (2.6 lb/hr) @15% O_2 1-hr avg (normal operation)
Bayonne EC, NJ	August 26, 2016, revised March 2023	Eight 66 MW SCCTs firing NG (and FO 720 hrs/yr), capable of operating as black start units	Oxidation catalyst and GCPs are pollution prevention (not PSD BACT) when firing NG. LAER applied when burning FO.	2 ppmvd @ 15% O_2 firing NG (LAER VOC limit while burning FO is 4.5 ppmvd @15% O_2)
Washington Parish EC, LA	May 23, 2018	Two 207 MW SCCTs firing NG (7000 hrs/yr)	GCP and NG fuel	-
LBWL Erickson Sta, MI	January 7, 2021 & January 11, 2022	One 667 MMBtu/hr NG fired SCCT	GCP	5 lb/hr

The proposed CERC project will be located in an area that is in attainment for all pollutants. PSD BACT VOC emission rates for recently-permitted (2015 to present) SCCT facilities (that entered a limit) are in the range of 1.6 ppmvd to 2.0 ppmvd at 15% O_2 using oxidation catalyst and/or GCPs, and natural gas as fuel (there are no RBLC entries for VOC from a currently-operating SCCT that burns FO). Also, in many cases, VOC did not trigger PSD permitting and was not entered into the RBLC.

Dominion has proposed controlling VOC using good combustion practices and an oxidation catalyst for the SCCTs. The oxidation catalyst is proposed for the dual purpose of controlling CO emissions and VOC emissions. The applicant proposed VOC limits, as follows, all @15% O_2 and as CH_4 (based on a 3-hour average using stack testing):

- 1.0 ppmvd when firing natural gas, with or without H_2
- 2.0 ppmvd when firing #2 fuel oil

As shown above, these proposed limits are more stringent than the PSD BACT determinations in the RBLC so these are accepted as PSD BACT for the proposed SCCTs.

b. Fuel gas heater

i. List of control technologies (Step 1)

- Good combustion practices (adequate temperature and gas residence time, clean fuel)
- Oxidation catalyst

ii. Technically feasible control options (Step 2)

- Good combustion practices are feasible and available for this unit
- Oxidation catalyst is feasible and available for these units

iii. Rank effectiveness of VOC control options (Step 3) remaining from Step 2

- 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. Evaluate most effective and achievable emission strategies for VOC from Step 3 and the effects on economics, energy, and the environment (Step 4):

VOC emissions from the fuel gas heater without oxidation catalyst would be 0.005 lb/MMBtu. It would not be economically feasible to reduce emissions further with add-on controls. Good combustion practices result in VOC emissions that are consistent with BACT at similar facilities at 0.005 lb/MMBtu.

v. BACT determination (Step 5)

DEQ concurs with Dominion that good combustion practices are BACT, resulting in emissions of 0.005 lb/MMBtu for VOC from the fuel gas heater.

c. <u>Black start generators</u>

VOC emissions from engines are primarily a function of unburned fuel. Therefore, efficient combustion (air-to-fuel mixing) is paramount in reducing this pollutant. Quantifying VOC from engines is complicated by the terminology describing emissions and emission standards, and the test methods used to measure these emissions.

Hydrocarbons (HC) include all hydrocarbons or total hydrocarbons (THC) measured by a Flame Ionization Detector (FID) calibrated with propane. This is the most common test method for engines. Some oxygenated hydrocarbons are not similar to propane, however (i.e., formaldehyde and methanol), and are not captured by this technique, so they are extracted and measured with chromatography. These compounds are described as total organic gas (TOG). Non-methane hydrocarbons (NMHC) exclude methane, which has relatively low reactivity for ozone formation. Methane is measured using FID calibrated for methane. When the methane component is subtracted from the THC + TOG, the results are known as non-methane hydrocarbon (NMHC) and non-methane organic gas (NMOG).

"Regulated" hydrocarbons are those that react to form ozone. These are known as volatile organic compounds (VOC) and exclude methane, ethane, and acetone. EPA has developed conversion factors that can better characterize VOC emissions.[2].

For diesel engines: $\frac{1.053 \, {}^{VOC}/_{THC}}{0.984 \, {}^{NMHC}/_{THC}} = 1.07 \, {}^{VOC}/_{NMHC}$

This indicates that VOC emissions could be 7% higher than NMHC values.

i. List VOC control technologies for large, emergency RICE (Step 1).

- Oxidation catalyst
- GCPs (efficient engine design, maintenance, clean fuel, limit hours of operation)

2 Assessment and Standards Division, Office of Transportation and Air Quality. (2010). *Conversion Factors for Hydrocarbon Emission Components* (EPA-420-R-10-15). US Environmental Protection Agency. https://nepis.epa.gov/.

ii. Technically feasible control options (Step 2)

- Oxidation catalyst is technically feasible for a diesel RICE
- GCPs are technically feasible

iii. Rank effectiveness of VOC control options (Step 3) remaining from Step 2

- Oxidation catalyst can reduce VOC emissions.
- GCPs minimize emissions but do not reduce emissions.

iv. Evaluate most effective and achievable emission strategies for VOC from Step 3 and the effects on economics, energy, and the environment (Step 4)

- Oxidation catalyst would be more cost-effective on a combustion unit that operated for longer periods and produced more emissions. The black start engine-generators are limited to only 500 hours of operation per year. It would not be economically feasible to install oxidation catalysts on the black start engines.
- GCPs are also effective at minimizing VOC emissions and do not result in negative effects on economy, energy or the environment.

v. Selection of BACT for VOC from the black start engines (Step 5)

A RBLC search of large diesel engines (Process Code 17.11), greater than 2000 kW (2600 bhp), permitted since 2015, subject to VOC BACT for PSD, returned about 37 entries. Of those large engine/generators, about 29 listed a BACT limit based on NSPS Subpart IIII. This was in the form of the Tier 2 standard of 6.4 g/kW-hr (4.8 g/bhp-hr) in Table 2 of Appendix I in 40 CFR, Part 1039, and/or compliance with NSPS Subpart IIII (or purchasing a certified engine meeting the NSPS standard, either Tier 2 or Tier 4). Eight entries with BACT described as compliance with NSPS, Subpart IIII, had no numerical limits associated with the generators.

At issue is that the NSPS standard in Subpart IIII for Tier 2 units, are not for VOC but, rather, NOx + non-methane hydrocarbon (NMHC). And, as mentioned above, VOC can actually be higher than NMHC measurements due to different measurement techniques.

A few states sought to estimate the NMHC portion in various ways:

- For four 3,000 kWe black start engines at a power plant, Indiana used an estimate of **0.24 g/bhp-hr** for VOC (and 4.56 g/bhp-hr for NOx, which totals to 4.8 g/bhp) or about 5% NMHC, based on “CARB Emission factor for CI Diesel Engines – Percent HC in Relation to NMHC-NOx” policy.
- Louisiana permitted three 3,000 hp emergency generators at a methanol plant using the 0.09 lb/MMBtu factor for TOC from AP-42, Table 3.4-1 (equivalent to **0.32 g/hp-hr**) to comply with the NSPS Subpart IIII standard. The permit limits were expressed in lb/hr.
- For a 2000 kW engine, Ohio compared the Tier 2 standard for NOx + NMHC with the Tier 1 standards for HC and NOx to get a ratio of 0.79 g/kWh HC out of the 6.4 g/kWh NOx + NMHC (about 12% NMHC). This is equivalent to **0.58 g/hp-hr**. BACT was “state-of-the-art combustion design.”

- Arkansas permitted six 2700 kW engines at a steel factory, at 1.55 g/kW-hr "VOC" (and 4.86 g/kW-hr NOx), based on an assumption of 24% NMHC in 6.4 g/kW-hr NOx + NMHC in the exhaust from those engines. This is equivalent to **1.14 g/hp-hr**.

Alaska permitted three 2695 bhp emergency generators at an oil/gas production facility at 0.0007 lb/hp-hr, based on the TOC emission factor in AP-42, Table 3.4-1 (equivalent to **0.32 g/hp-hr**). Except for stating that the limit represented PSD BACT, no other description was included for control strategies. No mention was made of the NSPS standards.

Only three entries out of the 37 found in the RBLC search required oxidation catalyst to control VOC. Two of those were permitted in Alaska, which is not a non-attainment area for ozone (NOx and VOC), but which contains several large National Parks, which are Class I areas where restrictions on ozone are tight. One of those was a single 4060 hp emergency engine at a gas treatment plant, limited to **0.18 g/hp-hr**. This is the "not to exceed value," which is the NSPS Tier 4 standard (0.14 g/hp-hr HC) multiplied by 1.25. The second Alaska facility, a gold mine, was permitted for twelve 17,000 kW (17 MW) non-emergency generators, which were limited to 0.21 g/kW-hr (**0.15 g/hp-hr**). The third facility, in West Virginia, stated that the BACT determination for a 2100 hp emergency generator was GCP with oxidation catalyst, however the limit for the unit was 6.4 g/kWh (NSPS Subpart IIII, Tier 2).

Three 2922 hp generators at a steel plant in Kentucky were listed with BACT as GCP but had no numerical limit. The same company had a 3634 hp generator permitted at a facility in Arkansas at 0.8 g/kW-hr, with no description of any control methods.

As mentioned for CO BACT for the black-start engines, the manufacturer for the proposed project has not yet been selected, no spec sheet can be reviewed. However, a new engine (2025 or later) would be very efficient and would be designed to meet Tier 2 standards at a minimum. Dominion estimated VOC emissions from the engines would be 1.92 g/kw-hr, based on an assumption that VOC makes up 30% of the NOx + NMHC standard. DEQ determines that VOC BACT for the black-start engines would be the purchase of a Tier 2 certified unit.

d. <u>Fuel Tanks</u>

The 24,500-gallon fuel tank on each of the black start engine-generator sets is integral to the unit. Total VOC from those tanks, assuming maximum annual operation of the engine-generator sets, is less than three pounds/year. Proper maintenance will be required. VOC emissions from the 20 million-gallon diesel fuel tank for the combustion turbines, based on maximum annual operation of the SCCTs on diesel fuel, are 1.6 tons/yr. The use of a fixed roof tank to hold diesel fuel and proper maintenance is BACT for this type of unit.

4. Particulate Matter Controls (PM2.5) – Particulate matter emissions less than two and a half microns in size (PM2.5) 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 PM2.5, are attributable primarily to the formation of sulfates (fuel sulfur content) and inorganic compounds.

a. Combustion Turbines

i. List of PM2.5 control technologies (Step 1)

- GCP (low ash/low sulfur fuel, efficient operation, tuning, maintenance, limits on fuel oil combustion)
- Add-on controls such as ESP, scrubbers or baghouses

ii. Eliminate technically infeasible control technologies (Step 2)

GCPs and the use of low-ash fuels, like natural gas (with or without hydrogen) and low sulfur fuel oil are readily available and technically feasible to use in simple cycle turbines.

Add-on PM controls (such as ESPs, scrubbers or baghouses) are not recommended for combustion turbines burning natural gas or fuel oil because the PM particles are quite small (<1 micron) and the air volume is quite large, making the concentration of PM2.5 so low that the efficiency of add-on particulate control would be quite low. These add-on controls are not technically feasible for a SCCT.

iii. Rank effectiveness of PM2.5 control options (Step 3) remaining from Step 2

GCPs will reduce the formation of PM2.5.

iv. Evaluate most effective and achievable emission strategies for PM2.5 from Step 3 and the effects on economics, energy, and the environment (Step 4)

GCPs do not have negative effects on economy, energy, or the environment.

v. Select BACT for PM2.5 (Step 5)

PM2.5 emissions should be lowest during full load, while burning natural gas and highest during low load and/or burning fuel oil. Emission factors, expressed as lb/MMBtu for each fuel, can vary depending on load and fuel consumption. However, in many cases, a lb/hr emission limit may apply at various loads since, as loads drop, combustion is less efficient so the mass of PM2.5 may increase, however, at the same time, less fuel is being combusted so the Btus from fuel is lower. Thus, emissions on a lb/hr basis are also dependent on the size of the turbine. Factors affecting PM2.5 emissions that cannot be controlled by the facility are percent relative humidity, atmospheric pressure, and ambient air temperature.

Fuel sulfur content is important because sulfates that are created are a component of PM2.5 emissions.

A search of the RBLC for PM2.5 limits for SCCTs that have started operation and are permitted to combust natural gas or fuel oil returned a list of approximately 14 facilities plus another was found outside of the RBLC (Ocotillo Power, AZ). As can be seen in Table 8, BACT (or “pollution prevention” practices) PM2.5 emission factors range from 0.003 lb/MMBtu to 0.008 lb/MMBtu (5 lbs/hr to 18 lbs/hr) when firing natural gas and 14 lbs/hr to 60.6 lbs/hr (0.02 lb/MMBtu) on fuel oil. Two Florida facilities limited the fuel sulfur content in natural gas to 2 gr/100 scf.

Table 8 – PM2.5 RBLC Turbine Limits

Facility	Permit date	Equipment	BACT	PM2.5 Limit
Elk EC, TX	May 20, 2015	Three 202 MW SCCT (~1,840 MMBtu/hr) - 4,572 hrs/yr ea	Pipeline quality NG, GCP, limit on hours of operation	-
Lauderdale Plant, FL	August 25, 2015	Five 241 MW (~2,200 MMBtu/hr) net dual fuel SCCTs - 3,390 hrs per turbine 12-mo average	Clean fuels	2 gr/100 scf sulfur content in NG, 0.15% sulfur in #2 fuel oil
Fort Myers Plant, FL	September 10, 2015	Two nominal 250 MW SCCT (nominal heat input of 2,262.4 MMBtu on natural gas and 2,353.7 MMBtu on #2 oil) replacement units.	Clean fuels	2 gr/100 scf sulfur content in NG, 0.15% sulfur in #2 fuel oil
Cameron LNG, LA	March 3, 2016	Six 1,069 MMBtu/hr (~118 MW) gas turbines firing NG	GCP and NG	0.008 lb/MMBtu
PSEG Fossil, Sewaren, NJ	March 10, 2016	One 345 MW dual fuel CT that can operate without DB (Unit 7), 3,311 MMBtu/hr on natural gas; 3,452 MMBtu/hr on #2 fuel oil	Clean fuel, NG	14.4 lb/hr NG no DB 60.6 lb/hr #2 fuel oil
Ocotillo Power, AZ	March 22, 2016	Five 104 MW (~950 MMBtu/hr) SCCTs firing NG	-	5.4 lbs/hr (1-hr avg)
Bayonne EC, NJ	August 26, 2016, revised March 2023	Eight 66 MW SCCTs firing NG (and FO 720 hrs/yr), capable of operating as black start units	Clean-burning fuel, NG and #2 fuel oil	5.0 lb/hr on NG 14.0 lb/hr on #2 fuel oil (basis is pollution prevention, not PSD BACT)
Invenergy Nelson Expansion, IL	September 27, 2016	Two 190 MW SCCTs (~1,7200 MMBtu/hr) on NG	Turbine design and GCP	0.005 lb/MMBtu
Doswell Energy Ctr, VA	October 4, 2016	Two SCCT, 187 MWh (1,961 MMBtu/hr) on NG (4,372,500 MMBtu/yr)	Good combustion, operation, & maintenance, pipeline quality NG	0.006 lb/MMBtu
Montpelier GS, IN	January 6, 2017	Four 60 MW (270.9 MMBtu/hr) NG CTs with #2 fuel oil backup (500 hours)	GCP and NG as primary fuel	0.007 lb/MMBtu NG 0.02 lb/MMBtu #2 fuel oil
Mustang St, TX	August 16, 2017	three SCCTs. Increase Unit 6 SCCT (162.8 MW) to 3,000 hrs/yr.	GCP and pipeline quality NG	-
Washington Parish EC, LA	May 23, 2018	Two 207 MW SCCTs firing NG (7000 hrs/yr)	GCP and low sulfur fuel (pipeline quality NG)	0.003 lb/MMBtu
LBWL Erickson Sta, MI	January 7, 2021 & January 11, 2022	One 667 MMBtu/hr (~73.4 MW) NG fired SCCT	GCP, pipeline quality NG, inlet air conditioning	0.007 lb/MMBtu

Facility	Permit date	Equipment	BACT	PM2.5 Limit
TVA Colbert CT Plant, AL	September 21, 2021	Three 229 MW (~2,000 MMBtu/hr) SCCTs firing NG	-	0.008 lb/MMBtu 18 lbs/hr

The normal operation of the 250 MW turbines proposed for the CERC project would be at loads between approximately 30% and 100%. On average, when combusting natural gas (with or without hydrogen), the turbines could operate with PM2.5 emissions around 0.006 lbs/MMBtu and 14.3 lbs/hr, and around 0.028 lbs/MMBtu while combusting fuel oil (annual PM2.5 emission limits are based on these values). However, Virginia permitting procedures typically require short-term (hourly) emissions to be based on maximum expected values. This ensures that air quality modeling represents the maximum impact to air quality. Therefore, Dominion proposes the following permit limits.

While combusting fuel oil (0.15% S):

- 0.032 lb/MMBtu as a maximum at ~30% load (average of three test runs)
- 45.0 lb/hr as a maximum at ~70% load (average of three test runs)

While combusting natural gas, with or without hydrogen (S = 1.0 gr/100 scf):

- 0.0135 lb/MMBtu as a maximum at ~ 30% load (average of three test runs)
- 19.7 lb/hr as a maximum at ~ 100% load (average of three test runs)

DEQ concurs that the use of GCP, including low ash/low sulfur fuel, efficient operation, tuning, maintenance, and limits on operation, represents BACT for $PM_{2.5}$ control for the proposed combustion turbines.

b. Fuel Gas Heater

The proposed fuel gas heater is a relatively small unit which burns natural gas as fuel and will typically only operate on cold days. Annual emissions of PM2.5 are estimated to be less than 0.6 tons/year. Similar units in the RBLC (natural gas-fired heaters - that are not boilers - between 10 and 20 MMBtu/hr), indicate GCPs and limiting fuel use to only pipeline quality natural gas are BACT, with emission limits at 0.007 – 0.008 lb/MMBtu or 0.075 to 0.15 lb/hr.

Dominion proposes BACT to be GCP and NG fuel with a sulfur content of no more than 0.1 gr/100 scf (on an annual average), resulting in PM2.5 emissions of 0.007 lb/MMBtu. DEQ agrees that this constitutes BACT for the heater.

c. Black start generators

PM2.5 emissions from engines are primarily a function of unburned fuel, sulfates, and nitrates. Therefore, efficient combustion (air-to-fuel mixing) and limiting sulfur is paramount in reducing this pollutant. As mentioned earlier, the specific model of the proposed engine-generator sets has not been chosen at this point, however newer engines should be very efficient and would emit a small amount of PM2.5 when operated properly.

A RBLC search of large diesel engines (Process Code 17.11), greater than 2000 kW (2600 bhp), permitted since 2015, subject to PM2.5 BACT for PSD, returned about 40 entries.

Primarily, PSD BACT was determined to be compliance with the NSPS Subpart IIII Tier 2 standard for PM of 0.2 g/kW-hr (0.15 g/hp-hr) for 33 entries. Some of those entries had the NSPS standard as a limit, some did not state a numerical limit, and some added GCP and limits on hours of operation in addition to "compliance with 40 CFR 60 Subpart IIII."

It should be noted that the NSPS standards are in terms of filterable PM (as determined by an EPA D2 Cycle 5-mode weighted testing protocol to achieve Tier 2 or Tier 4 certification) and do not accurately represent PM2.5 total particulate (which includes a condensable fraction). Permit limits are recommended to be the nominal (steady-state) emissions determined by testing at various loads by the manufacturer, and multiplied by a factor of 1.2 to 1.6 to more accurately estimate emissions during actual conditions in the ambient (and variable) environment.

One of the entries in the RBLC requiring purchase of an engine that meets the Tier 2 standards was for forty-six 5,000 hp engines at a semiconductor plant in Ohio. The permit limit was 0.07 lb/hr (which is more like 0.006 g/hp-hr, not 0.15 g/hp-hr). The actual permit explains that those engines shall be "equipped with a diesel particulate filter" but this was not stated in the RBLC. This would be understandable for so many large diesel engines and would explain the lower limit. Ohio permitted another 5000 hp emergency engine, located at a nitrogen plant, at 0.2 lb/hr, stating also that the "standard limit" was 0.03 g/kW-hr (NSPS Tier 4) and the NSPS limit is 0.2 g/kW-hr (Tier 2).

A liquid natural gas plant in Alaska required a 4,060 hp black start engine to meet Tier 4 standards of the NSPS (permit limit for PM2.5 of 0.045 g/hp-hr is derived by the Tier 4 standard of 0.022 g/hp-hr and a "not-to-exceed" factor of 1.5). The LNG pipeline will be adjacent to Denali National Park which is a Class 1 area for visibility-impairing pollutants. Two other entries (OH and PA) required one 2000 kW and one 2300 KW emergency engine to meet Tier 4 standards (of about 0.03 g/kW-hr) and "compliance with 40 CFR 60 Subpart IIII" as was stated, would encompass that. These NSPS limits are typically applied to non-emergency engines. These could be voluntary limits proposed by the permitted facilities.

The remainder of the limits in the RBLC were slightly higher than the NSPS standards, most likely due to acknowledging a "not-to-exceed" factor, vendor information or other consideration not noted in the RBLC.

Dominion proposed PM2.5 emissions from the engines would meet 0.23 g/kW-hr (0.2 g/kW-hr NSPS standard plus 0.033 g/kW-hr condensable fraction).

A certified Tier 2 emergency engine is required to be purchased for the CERC project. Therefore, the PM2.5 emissions would not exceed 2.19 lb/hr [(filterable PM 0.2 g/kw-hr x 3500 kW/453.59 g/lb x 1.25) + (condensable 0.0077 lb/MMBtu x 33.73 MMBtu/hr) = 2.188 lb/hr] or 0.6 tons/year (2.19 lb/hr x 500 hrs/yr ÷ 2000 lb/ton) from each engine-generator set.

Add on controls for PM2.5 emissions from these new emergency engine generator sets are not economically feasible. These units are operated intermittently for brief periods. A diesel particulate filter would, at most, reduce emissions by a half a ton/year for each engine (if operated at 500 hours/year).

Therefore, PSD BACT for PM2.5 from the black start generators at the CERC shall be the purchase of a certified Tier 2 engine, low sulfur fuel, and GCP.

5. Startup/shutdown of the SCCTs

BACT applies during startup and shutdown (SU/SD) of the turbines. During SU/SD, some post-combustion controls are not working at the optimum level of control, however, during these periods, the turbines are also not operating at their highest output and other emissions may be reduced for that reason. Dominion uses automated systems to control combustion in the turbines. These systems are designed to operate in the most efficient manner, which, in turn, minimizes emissions. Good combustion practices including controlling the fuel/air mixing, temperature, and gas residence time during combustion would minimize emissions . Dominion submitted BACT for SU/SD for the turbines as follows:

- CO - Technically feasible CO controls during SU/SD include oxidation catalyst, DLN (which can result in lowering CO as well as NOx), and good combustion practices. Of these, oxidation catalyst is most effective, followed by good combustion practices and DLN. A combination of these controls will be employed to minimize CO during SU/SD. Compliance with the limits shown in Table 9 below will be based on CEMS.
- Add-on controls for PM2.5, like electrostatic precipitators or baghouses are not usually applied to combustion turbines, especially for alternative operating scenarios such as SU/SD. The only feasible control for PM2.5 would be the use of clean fuel, such as natural gas, followed by good combustion practices. Dominion proposes limitations on the duration of SU/SD events to minimize PM2.5 emissions during SU/SD. Annual emissions of PM2.5 attributed to SU/SD were included in Condition 39 of the permit.
- Although VOC controls would be similar to CO controls, the effectiveness of these controls could be minimal. Dominion proposes limitations on the duration of SU/SD events to minimize VOC emissions during SU/SD. Annual emissions of VOC attributed to SU/SD were included in Condition 39 of the permit.
- GHG – No alternate BACT was proposed since the BACT limitations could be met during SU/SD.

Table 9 - Summary of PSD BACT for SU/SD for turbines

Pollutant	BACT during startup	BACT during shutdown
CO (measured by CEMS)	No more than 30 minutes per occurrence. Natural gas – 366 lbs/event Fuel oil – 1,036 lbs/event	No more than 15 minutes per occurrence. Natural gas – 152 lbs/event Fuel oil – 246 lbs/event
PM2.5	No more than 30 minutes per occurrence	No more than 15 minutes per occurrence.
VOC	No more than 30 minutes per occurrence	No more than 15 minutes per occurrence.
GHG	No more than 30 minutes per occurrence	No more than 15 minutes per occurrence.

B. 9VAC5-50-260 Article 6 BACT

BACT applicability is pollutant-by-pollutant based on the permitting applicability thresholds. Each affected emissions unit emitting a pollutant that is subject to Article 6 permitting shall apply Article

6 BACT for that pollutant (9VAC5-50-260.C). Article 6 BACT is applicable to NOx, SO_2, PM, and PM10.

Article 6 BACT does not require a top-down BACT analysis as was done for the PSD BACT pollutants. The definition of best available control technology as used in 9VAC5-50-260 is defined in 9VAC5-50-250.

1. Nitrogen Oxides

   a. Combustion turbines

   NOx emissions are formed in the exhaust of a fuel-burning unit as a result of combustion of the fuel. The primary factors influencing the generation of NOx emissions are temperature and residence time within the combustion zone. Generally, the effect of the combustion zone temperature and residence time on NOx emissions generation is the exact opposite of their effect on CO emissions generation. Higher combustion zone temperatures and residence times leads to higher NO_x emissions.

   Dominion has proposed to control NOx with a combination of dry low-NOx burners (DLNB), SCR when burning natural gas, and fogging/water injection when burning fuel oil.

   Emissions of NOx during normal operation are proposed as follows:

   - 2.5 ppmvd @15% O_2, using SCR, during normal operating loads when combusting natural gas with or without hydrogen, on a 4-hr rolling average, as measured with CEMS.
   - 5.0 ppmvd @15% O_2, using DLNB and water injection, during normal operating loads when combusting fuel oil, on a 4-hr rolling average, as measured with CEMS.

   Emissions of NOx during startup and shutdown are proposed as follows, using good air pollution control practices for minimizing emissions and, as technically feasible SCR and water injection:

   - 52 lb/turbine SU on natural gas, with or without H_2
   - 20 lb/turbine SD on natural gas, with or without H_2
   - 143 lb/turbine SU on fuel oil
   - 62 lb/turbine SU on fuel oil

   Compliance with these limits are demonstrated by CEMS.

   These BACT emission limits are as stringent as PSD (or even LAER) determinations for similar equipment. Therefore, DEQ concurs that these are acceptable Article 6 BACT limits.

   b. Fuel gas heater

   NOx emissions will be minimized by installing a unit with ultra-low NO_x burners that would achieve an emission rate of 0.011 lbs/MMBtu. DEQ accepts this limit as Article 6 BACT.

c. Black start generators

Add-on NOx controls, such as SCR, are not typically used on emergency units that operate intermittently. The proposed units will be certified to meet the Tier 2 emission standards in NSPS Subpart IIII, without add-on NOx or PM controls. The NSPS Subpart IIII Tier 2 emission standard for NOx + NMHC is 6.4 g/kW-hr. The units are proposed to be Tier 2 certified, 3500 kW-hr engine-generator sets. The specific model of diesel engine has not yet been selected, so no specification sheet is available from a manufacturer detailing the “not-to-exceed” pollutant levels. However, if the units are certified to meet the Tier 2 standard, based on proper operation and maintenance of the unit, emissions of NOx + NMHC should be expected to meet the standard.

Dominion has proposed that NOx would be approximately 70% of this standard and VOC would be 30%, so they estimate NOx emissions to be 70% x 6.4 g/kW-hr = 4.48 g/kW-hr.

DEQ determines that NOx BACT for the black start generators will be to purchase Tier 2 certified engines.

2. PM, PM10, SO_2, and H_2SO_4

a. Combustion turbines

PM and PM10 emissions would be controlled by the same methods as proposed for PM2.5 emissions evaluated for PSD BACT in section IV.A.4.a. DEQ concurs that the use of GCP, including low ash/low sulfur fuel, efficient operation, tuning, maintenance, and limits on operation, represents BACT for PM and PM10 for the proposed combustion turbines. Emission limits below reflect maximum short-term (3-hour average) emissions during operation at low load. Compliance with PM10 limits will be based on stack testing as per Condition 52. Concurrent visible emission evaluations shall also be performed:

- PM
  - 0.0072 lb/MMBtu while burning natural gas
  - 0.0063 lb/MMBtu while burning natural gas with up to 10% hydrogen
  - 0.0165 lb/MMBtu while burning #2 fuel oil
- PM10
  - 0.014 lb/MMBtu while burning natural gas, with or without hydrogen
  - 0.04 lb/MMBtu while burning #2 fuel oil

SO_2 and H_2SO_4 emissions are based on the sulfur content of the fuel. Therefore, BACT reflects the limitations on sulfur content. The natural gas, with or without hydrogen, is limited to a maximum sulfur concentration of 1.0 gr/100 scf. The fuel oil has a sulfur concentration of 0.0015%. These emission limits apply at all times:

- SO_2
  - 0.0034 lb/MMBtu (all fuels)

- H_2SO_4
  - 0.00023 lb/MMBtu (3-hour average) while burning natural gas
  - 0.00023 lb/MMBtu (3-hour average) while burning natural gas with hydrogen
  - 0.0013 lb/MMBtu (3-hour average) while burning #2 fuel oil

b. Fuel gas heater

PM, PM10, SO_2 and H_2SO_4 emissions will be minimized by GCP and natural gas fuel with an annual sulfur content of 0.4 gr/100 scf, resulting in the following emission limits:

- PM emissions of 0.002 lb/MMBtu.
- PM10 emission of 0.007 lb/MMBtu.
- SO_2 and H_2SO_4 emissions of 0.0012 lb/MMBtu and 0.0003 lb/MMBtu, respectively (not included in the permit for the fuel gas heater as values result in lb/hr and tons/yr emissions below the 0.5 de minimis value for inclusion in an Article 6 permit emission limitation).

c. Black Start Generators

PM, PM10, SO_2, and H_2SO_4 emissions from the black start engine generator sets will be controlled by GCP and the use of #2 fuel oil as fuel. GCP and limits on fuel sulfur content result in the following BACT emission limits for the black start generators:

- PM: 0.20 g/kW-hr
- PM10: 0.23 g/kW-hr
- SO_2: 0.00154 lb/MMBtu
- H_2SO4: 0.00012 lb/MMBtu

C. Summary of BACT determinations – the following table summarizes the BACT determinations for the proposed CERC facility equipment:

Table 10 - Summary of BACT determinations

Pollutant/Unit	Primary BACT Limit	Control	Compliance
NOx/Turbines (Article 6)	2.5 ppmvd @ 15% O_2 (4-hr avg) on NG 5.0 ppmvd @ 15% O_2 (4-hr avg) on #2 oil	DLN burners/SCR Water injection/SCR	Initial stack test on both fuels & NOx CEMS 4-hr avg
NOx/Turbines during startup and shutdown (Article 6)	SU on natural gas - 52 lbs/event SU on fuel oil - 143 lbs/event SD on natural gas - 20 lbs/event SD on fuel oil - 62 lbs/event	Good air pollution control practices for minimizing emissions and, as technically feasible, SCR and water injection	NOx CEMS
NOx/Fuel Gas Htr (Article 6)	0.011 lbs/MMBtu	Ultra low-NO burners	Initial stack test

Pollutant/Unit	Primary BACT Limit	Control	Compliance
NOx/Black Start Generators (Article 6)	4.48 g/kW-hr	Good combustion practices	Purchase Tier 2 certified engines
CO/Turbines (Article 8)	2.0 ppmvd on all fuels (4-hour avg.)	Oxidation catalyst Good combustion practices	CO CEMS 4-hr avg
CO/Turbines during startup and shutdown (Article 8)	SU on natural gas – 366 lbs/event SU on fuel oil – 1,036 lbs/event SD on natural gas – 152 lbs/event SD on fuel oil – 246 lbs/event	SU 30 minutes SD 15 minutes. A combination oxidation catalyst and DLN burners	CO CEMS
CO/Fuel Gas Htr (Article 8)	0.037 lb/MMBtu	Clean fuel and good combustion practices	Stack test
CO/Black Start Generators (Article 8)	3.5 g/kW-hr	Good combustion practices	Purchase Tier 2 certified engines
PM10/Turbines (Article 6)	0.014 lb/MMBtu on natural gas 0.04 lb/MMBtu on #2 fuel oil	Low sulfur/carbon fuel and good combustion practices	Stack test, three 1-hr tests
PM10/Turbines during startup and shutdown (Article 8)		SU 30 minutes SD 15 minutes.	Record duration of SU & SD events
PM10/Fuel Gas Heater (Article 6)	0.007 lb/MMBtu	Low sulfur/carbon fuel and good combustion practices	Combust only natural gas.
PM10/Black Start Generators (Article 6)	0.23 g/kW-hr	Low sulfur fuel and good combustion practices	Purchase Tier 2 certified engines
PM2.5/Turbines (Article 8)	0.014 lb/MMBtu on natural gas 0.04 lb/MMBtu on #2 fuel oil	Low sulfur/carbon fuel and good combustion practices	Stack test, three 1-hr tests
PM2.5/Turbines startup and shutdown (Article 8)		SU 30 minutes SD 15 minutes	Record duration of SU & SD events.
PM2.5/Fuel Gas Heater (Article 8)	0.007 lb/MMBtu	Low sulfur/carbon fuel and good combustion practices	Combust only natural gas
PM2.5/Black Start Generator (Article 8)	0.23 g/kW-hr	Low sulfur fuel and good combustion practices	Purchase Tier 2 certified engines
VOC/Turbines (Article 8)	1.0 ppmvd @15% O_2 on natural gas 2.0 ppmvd @15% O_2 on #2 fuel oil	Oxidation catalyst Good combustion practices	Stack test and CO CEMS 3-hr average
VOC/Turbines startup and shutdown (Article 8)		SU 30 minutes SD 15 minutes	Record duration of SU & SD events.
VOC/Fuel Gas Heater (Article 8)	0.005 lb/MMBtu	Good combustion practices, operator training, and proper design, construction and maintenance	Combust only natural gas

Pollutant/Unit	Primary BACT Limit	Control	Compliance
VOC/Black Start Generators (Article 8)	1.92 g/kW-hr	Good combustion practices	Purchase Tier 2 certified engines
SO_2/Turbines (Article 6)	0.0034 lb/MMBtu, S = 1.0 gr/100 scf max	Low sulfur fuel	Fuel monitoring, stack test
SO_2/Fuel Gas Htr (Article 6)	S = 0.4 gr/100scf (12-month avg)	Low sulfur fuel	Fuel monitoring
SO_2/Black Start Generators (Article 6)	0.00154 lb/MMBtu	#2 fuel with 15 ppm S	Fuel certification and hours of operation
H_2SO_4/Turbines (Article 6)	0.0023 lb/MMBtu on 100% natural gas 0.0023 lb/MMBtu on natural gas + H_2 0.0013 lb/MMBtu on #2 oil	Low sulfur fuel	Fuel monitoring
H_2SO_4/Fuel Gas Htr (Article 6)	S = 0.4 gr/100 scf (12-month avg)	Low sulfur fuel	Fuel monitoring
H_2SO_4/Black Start Generator (Article 6)	0.00012 lb/MMBtu	#2 fuel oil with 15 ppm S	Fuel monitoring
CO_2e/Turbines (Article 8)	120 lb CO_2e/MMBtu on natural gas 160 lb CO_2e/MMBtu on fuel oil	Energy efficient combustion practices and low GHG fuels	Stack test for CO_2 while measuring heat input for both fuels then calculation
CO_2e/Turbines startup and shutdown (Article 8)		SU 30 minutes SD 15 minutes	Record duration of SU & SD events
CO_2e/Fuel Gas Heater (Article 8)		Natural gas fuel and efficient design and operation	Manufacturer specifications and maintenance.
CO_2e/Black Start Generators (Article 8)		High efficiency design and operation and good combustion practices	Records of manufacturer's operating procedures and maintenance.
CO_2e/Circuit Breakers (Article 8)	0.5% leakage rate	Enclosed-pressure type breaker and leak detection	Audible alarm with decreased pressure.
CO_2e/Fugitive Equipment Leaks (Article 8)		BMP, monitoring and leak repair plan	Recordkeeping

V. Summary of Potential Emissions Increases (see detailed emission calculations in APPENDIX A)

Table 11 – Potential Emission increases (tons/yr) without netting

PM	PM10	PM2.5	CO	NOx	SO_2	H_2SO_4	VOC	CO_2e
81.8	153.9	153.9	825.3	353.3	27.8	18.7	162.5	2,214,344

VI. Dispersion Modeling (results are summarized in the Modeling Reports in APPENDIX C)

A. Criteria Pollutants

1. PSD - As stated in Section III.B, PM2.5 and CO triggered permitting under PSD regulations (so did CO_2e and VOC, however CO_2e is a regulated pollutant but not a criteria pollutant and has no NAAQS so modeling is not required for GHG, and VOC itself does not have a NAAQS standard but is included in ozone modeling, along with NOx). An air quality analysis via dispersion modeling was conducted to demonstrate compliance with the NAAQS. For the impact of the project on ambient ozone concentrations, a quantitative analysis was performed in accordance with current EPA guidance.

   Modeling was completed by Dominion's consultants and submitted to the Office of Air Quality Assessments for analysis. Worst case short-term emissions were used for the short-term analyses and annual emissions, based on maximum load and airflow through the stacks, were used for annual analyses.

   The results of the analyses demonstrate that the project will not cause or contribute to exceedances of the 1-hr and 8-hr CO NAAQS or the 24-hr and annual PM2.5 NAAQS. And the NOx and VOC emissions were evaluated along with ambient background ozone concentration and were found to be below the 8-hr ozone NAAQS.

   Additionally, conservative modeling demonstrated that the Class I short-term and annual PSD increments would not be exceeded.

2. Article 6 – NOx (as NO_2), PM10, and SO_2 did not trigger PSD permitting, but they did trigger Article 6 permitting and have NAAQS. Therefore, analyses were done on these pollutants to see the impact this project would have on ambient air quality. Results demonstrated that none of these pollutants would violate the NAAQS on a short-term (NO_2, SO_2, PM10) or annual (NO_2, SO_2, but not PM10, which does not have an annual NAAQS) basis.

B. Toxic Pollutants – The facility is a major source of hazardous air pollutants and is subject to 40 CFR 63 MACT Subpart YYYY for combustion turbines (see Section III.F.1). Therefore, the State's Toxic Rule for applicability to Article 6 permitting was not required to be performed for this project. Although the Project is not subject to the DEQ Air Toxics Program, Dominion proactively evaluated the Project's HAP emissions against DEQ's exemption rates and SAACs. The results indicated that the project would not contribute to exceedance of any SAAC.

VII. Boilerplate

This permit follows the boilerplates for a minor NSR permit. PSD conditions and citations were added based on similar PSD permits issued within the last several years, to be consistent.

VIII. Initial Compliance Determination

A. Testing – initial stack testing is required for NO_x, VOC, PM_{10}, and $PM_{2.5}$ from the turbines and NO_x and CO from the fuel gas heater to show compliance with the BACT limits. 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 maximum sulfur content of the natural gas is

1.0 gr/100 scf and the annual average sulfur concentration is no more than 0.4 gr/100 scf. 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 turbines and diesel black start engines.

CO_2e testing on emissions from the turbines, while combusting gas and oil, will be required to determine the CO_2 emission factor for each fuel on a lb/MMBtu basis, then compliance with the CO_2e limit in the Condition 38 of the permit for each fuel is based on a calculation using additional factors for CH_4 and N_2O.

B. VEEs – an initial VEE will be required for the combustion turbines (for both fuels, at base load and 70% load). An initial VEE is required for the fuel gas heater.

IX. Continuing Compliance Determination

CEMS – will be required for NO_x (NSPS) and CO. 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 on the turbines to assure proper operation and performance.

Stack tests are required for VOC and PM2.5 every five years.

Fuel tracking is required for the fuel gas heater (including sulfur content). Annual emissions from the combustion turbines and the black start generators are limited by hours of operation, however fuel type and fuel parameters (sulfur content) must also be tracked.

Annual VEOs are required for the black start generators if they are operated during a 12-month period and followed up with a VEE if opacity is observed.

X. Title V Review

The Chesterfield County Power Station is a major Title V source and operates under a Title V/Acid Rain (Article 3 combined) permit, which includes all federally-enforceable requirements to which the facility is subject. An application for a significant modification to that permit to include the CERC project will be required no later than 12 months after the commencement of operation of the CERC.

XI. Public Participation and Notification

The applicant held an informational briefing on November 16, 2023, at the SpringHill Suites in Chester, VA to provide the community with information about the project as required by 9VAC5-80-1775.A of the Virginia Regulations.

Pursuant to 9 VAC 5-80-1775.K (Article 8) of the Regulations, a public briefing was held for the proposed project on August 7, 2025, followed by a comment period of at least 30 days, followed by a public hearing and an additional 30 days of public comment.

A public notice indicating the time and place of the public briefing was advertised in the Richmond Times-Dispatch on July 7, 2025, posted on the DEQ website, emailed to the public notice database, and posted on the Virginia Townhall site, as well as distributed to the local community through flyers posted at various public, commercial, and religious centers.

The applicant published a public notice regarding the project and advertising the public hearing on August 8, 2025 (60 days prior to the close of the public comment period (anticipate to be October 8, 2025). Copies were sent to local libraries and schools, adjacent property owners, and local government officials. A copy was posted on the CERC page maintained by DEQ.

Once the public comment period closes, DEQ will analyze and respond to those comments. An additional hearing will be held as per §10.1-1184.1 B of the Code of Virginia.

XII. Other Considerations

None

XIII. Recommendations

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

XIV. Attachments:

A. Appendix A – Calculation sheets

B. Appendix B – Dominion outreach activities

C. Appendices C1 & C2 – PSD and Article 6 Modeling Memos

APPENDIX A – Emission calculation spreadsheets

Facility Dominion Chesterfield CERC
Location Chesterfield County
Reg. No. 50396
Eng AMS

Emissions from EACH of the combustion turbines ES-33, ES-34, ES-35, ES-36

Capacity	234.4 MW	#2 fuel oil	8760 hrs/yr
	2451.7 MMBtu/hr	#2 fuel oil	750 hrs/yr
		Heat input	1839000 MMBtu/yr

#2 Fuel Oil Combustion		Uncontrolled		Controlled @ 750 hours			
pollutant	EF (lb/MMBtu)	lb/hr	ton/yr	Control	%	lb/hr	tons/yr
PM	0.0165	24.00	105.12	None	0	24.00	9.00
PM10*	0.0316	45.00	197.10	None	0	45.00	16.87
PM2.5*	0.0316	45.00	197.10	None	0	45.00	16.87
CO	0.0339	83.10	363.98	Ox Cat	85.9%	11.70	4.39
NOx	0.1645	403.30	1766.47	SCR	88.1%	47.90	17.96
SO_2	0.0018	4.50	19.71	None	0	4.50	1.69
VOC	0.0038	9.27	40.59	Ox Cat	27.7%	6.70	2.51
H_2SO_4	0.0012	3.00	13.14	None	0	3.00	1.13
CO_2	163.08	399,823.24	1,751,225.77	Efficiency	0	399,823.24	149,952.06
CH_4	0.0066	16.22	71.03	Efficiency	0	16.22	6.08
N2O	0.00132	3.24	14.19	Efficiency	0	3.24	1.21
CO2-e	163.62	401,135.79	1,756,974.76	Efficiency	0	401,135.79	150,444.33

Emissions based on engineering judgement and BACT determinations
*PM10 and PM2.5 include contributions from turbines, H_2SO_4, and condensable VOC.

Worst case lb/hr for PM10/PM2.5 is at 70% load.
Worst case lb/MMBtu for PM10/PM2.5 is at about 50% load.

Facility Dominion Chesterfield CERC
Location Chesterfield County
Reg. No. 50396
Eng AMS

Emissions from EACH of the combustion turbines ES-33, ES-34, ES-35, ES-36

Capacity	250 MW	natural gas	8760 hrs/yr
	2449 MMBtu/hr	natural gas	3240 hrs/yr
		Heat input	7,927,050 MMBtu/yr

Natural Gas Combustion with 10% Hydrogen		Uncontrolled		Controlled @ 3240 hours			
pollutant	EF (lb/MMBtu)	lb/hr	ton/yr	Control	%	lb/hr	tons/yr
PM filt	0.0063	11.80	51.68	None	0%	7.42	12.07
PM10*	0.0115	19.50	85.39	None	0%	14.20	23.10
PM2.5	0.0115	19.50	85.39	None	0%	14.20	23.10
CO	0.0149	36.49	159.83	Ox Cat	69%	11.20	18.13
NOx	0.0939	230.00	1007.40	SCR	90%	23.00	37.26
SO_2	0.0033	8.10	35.48	None	0%	3.30	5.34
VOC	0.0015	3.55	15.56	Ox Cat	10%	3.20	5.35
H_2SO_4	0.0022	5.50	24.09	None	0%	2.30	3.73
Lead	4.86E-07	0.0012	0.01	None	0%	0.00119	0.00193
CO_2	115.60	283,098	1,239,967	Efficiency	0	283,098	458,172
CH_4	0.0022	5	23	Efficiency	0	5	9
N2O	0.00022	1	2	Efficiency	0	1	1
CO2-e	115.72	283,388	1,241,240	Efficiency	0	283,388	458,643

Emissions based on engineering judgement and BACT determinations
*PM10 and PM2.5 includes contributions from turbines, and H_2SO_4 and condensable VOC.
Worst case lb/hr for PM10/PM2.5 is at 100% load.
Worst case lb/MMBtu for PM10/PM2.5 is at 50% load.
Short term PM10/PM2.5/SO_2/H_2SO_4 emissions based on 1.0 gr/100 scf sulfur content.
Annual PM10/PM2.5/SO_2/H_2SO_4 emissions based on 0.4 gr/100 scf sulfur on an annual average.

Facility Dominion Chesterfield CERC
Location Chesterfield County
Reg. No. 50396
Eng AMS

Emissions from EACH of the combustion turbines ES-33, ES-34, ES-35, ES-36

Capacity	250 MW	natural gas	8760 hrs/yr
	2445 MMBtu/hr	natural gas	3240 hrs/yr
		heat input	7927050 MMBtu/yr

Natural Gas Combustion		Uncontrolled		Controlled @ 3240 hours			
pollutant	EF (lb/MMBtu)	lb/hr	ton/yr	Control	%	lb/hr	tons/yr
PMfilt	0.0072	11.90	52.14	None	0	7.48	12.21
PM10*	0.0135	19.70	86.29	None	0	14.21	23.19
PM2.5*	0.0135	19.70	86.29	None	0	14.21	23.19
CO	0.0150	36.60	160.31	Ox Cat	69.1	11.30	18.23
NOx	0.0953	233.02	1020.65	SCR	90.0	23.30	37.78
SO_2	0.00335	8.20	35.92	None	0	3.40	5.55
VOC	0.0015	3.56	15.58	Ox Cat	10.0	3.20	5.19
H_2SO_4	0.00229	5.60	24.53		0	2.30	3.72
Lead**	4.89E-07	0.001195605	0.01	None	0.0	0.0012	0.0019
CO_2	117.01	286,085	1,253,050	Efficiency	0	286,085	463,764
CH_4	0.0022	5	24	Efficiency	0	5	9
N2O	0.00022	1	2	Efficiency	0	1	1
CO2-e	117.13	286,378	1,254,337	Efficiency	0	286,378	464,240

Emissions based on engineering judgement and BACT determinations

*PM10 and PM2.5 includes contributions from turbines, and H_2SO_4 and condensable VOC.

Worst case lb/MMBtu for PM10/PM2.5 is based on MECL and 1.0 gr/100 scf sulfur.

Short term PM10/PM2.5/SO_2/H_2SO_4 emissions based on 100% load and 1.0 gr/100 scf sulfur content.

Annual PM10/PM2.5/SO_2/H_2SO_4 emissions based on 0.4 gr/100 scf sulfur on an annual average.

**Lead emissions from natural gas combustion in turbines is negligible.

Facility Dominion Chesterfield CERC
Location Chesterfield County
Reg. No. 50396
Eng AMS

Start Up/Shut down Emissions 500 events/year
while combusting natural gas or natural gas+H

	Start up*		Shut down		Totals (4)	Total 4
Pollutant	lb/event	TPY	lb/event	TPY	TPY	TPY
PM NG	1.80	0.45	0.9	0.23	2.7	10.8
PM NG w/H	1.80	0.45	0.9	0.23	2.7	10.8
PM10 NG	3.58	0.89	1.8	0.45	5.4	21.47
PM10 NG w/H	3.58	0.89	1.8	0.45	5.4	21.47
PM2.5 NG	3.58	0.89	1.8	0.45	5.4	21.47
PM2.5 NG w/H	3.58	0.89	1.8	0.45	5.4	21.47
CO NG w/ or w/o H	365.68	91.42	152.2	38.05	517.9	2071.52
NOx NG	52.32	13.08	19.8	4.95	72.1	288.48
NOx NG w/H	52.32	13.08	19.8	4.95	72.1	288.48
SO_2 NG	3.50	0.88	0.9	0.23	4.4	17.663
SO_2 NG w/H	3.50	0.88	0.02	0.00533	3.5	14.09
VOC w/ or w/o H	64.80	16.20	31.2	7.80	96.0	384
H_2SO_4 100% NG	2.37	0.59	0.6	0.15	3.0	11.96
H_2SO_4 10% H	2.37	0.59	0.01	0.00	2.4	9.54
Lead NG	0.00	0.00	0.000132	0.00	0.0	0.0026
Lead NG w/H	0.00	0.00	0.000132	0.00	0.0	0.0026
GHG w/ or w/o H	120784.00	30196.00	31505.00	7876.25	152289.0	609156

The lb/event values were estimated by GE, Dominion and their consultant based on a startup event lasting no more than 30 minutes (1,031 MMBtu/event) and a shutdown event lasting 15 minutes (269 MMBtu/event), and 500 of each type of event per year. The duration and # of events will be limited by the permit.
*The facility cannot startup the turbines using the hydrogen-blended natural gas.

Facility Dominion Chesterfield CERC
Location Chesterfield County
Reg. No. 50396
Eng AMS

Start Up/Shut down Emissions 2000 events/year
while combusting natural gas or natural gas+H

	SU/SD	
Pollutant	lb/event	TPY
1,3-Butadiene	5.59E-04	5.59E-04
Acetaldehyde	5.20E-02	5.20E-02
Acrolein	8.32E-03	8.32E-03
Benzene	1.56E-02	1.56E-02
Ethyl Benzene	4.16E-02	4.16E-02
Formaldehyde*	9.23E-01	9.23E-01
Naphthalene	1.69E-03	1.69E-03
PAH	2.86E-03	2.86E-03
Propylene Oxide	3.77E-02	3.77E-02
Toluene	1.69E-01	1.69E-01
Xylenes	8.32E-02	8.32E-02

The lb/event values were estimated by GE, Dominion and their consultant based on a startup event lasting no more than 30 minutes (1,031 MMBtu/event) and a shutdown event lasting 15 minutes (269 MMBtu/event), and 500 of each type of event per year. The duration and # of events will be limited by the permit.
*The facility cannot startup the turbines using the hydrogen-blended natural gas.

Facility Dominion Chesterfield CERC
Location Chesterfield County
Reg. No. 50396
Eng AMS

EACH TURBINE

Start Up/Shut down Emissions 120 events/year
while combusting fuel oil

	Start up		Shut down		Totals ea	Totals 4
Pollutant	lb/event	TPY	lb/event	TPY	TPY	TPY 4
PM	10.0	0.6	5.0	0.3	3.6	14.4
PM10	20.5	1.2300	10.3	0.620	7.4	29.60
PM2.5	20.5	1.2300	10.3	0.620	7.4	29.60
CO	1036.0	62.16	245.500	14.730	307.6	1230.24
NOx	143.0	8.6	62.0	3.7	49.2	196.8
SO_2	2.0	0.1	0.5	0.03	0.6	2.4
VOC	101.0	6.1	47.0	2.8	35.5	142.08
H_2SO_4	1.3	0.08	0.3	0.02	0.4	1.6
GHG	168767	10126	44017	2641	51068	204272

The lb/event values were estimated by GE, Dominion and their consultant based on a startup event lasting no more than 30 minutes (1,031 MMBtu/event) and a shutdown event lasting 15 minutes (269 MMBtu/event). The duration and # of events will be limited by the permit.
SU/SD events while combusting fuel oil are limited to no more than 120 per year

Facility Dominion Chesterfield CERC
Location Chesterfield County
Reg. No. 50396
Eng AMS

Start Up/Shut down Emissions 480 events/year per turbine
while combusting fuel oil

Pollutant	SU/SD lb/event	TPY
1,3-Butadiene	2.08E-02	4.99E-03
Acetaldehyde		
Acrolein		
Benzene	7.15E-02	1.72E-02
Ethyl Benzene		
Formaldehyde*	3.64E-01	8.74E-02
Naphthalene	4.55E-02	1.09E-02
PAH	5.20E-02	1.25E-02
Propylene Oxide		
Toluene		
Xylenes		
Arsenic	1.43E-02	3.43E-03
Beryllium	4.03E-04	9.67E-05
cadmium	6.24E-03	1.50E-03
chromium	1.43E-02	3.43E-03
cobalt		
manganese	1.03E+00	2.47E-01
mercury	1.56E-03	3.74E-04
nickel	5.98E-03	1.44E-03
selenium	3.25E-02	7.80E-03

The lb/event values were estimated by GE, Dominion and their consultant based on a startup event lasting no more than 30 minutes (1,031 MMBtu/event) and a shutdown event lasting 15 minutes (269 MMBtu/event), and 500 of each type of event per year. The duration and # of events will be limited by the permit.
*The facility cannot startup the turbines using the hydrogen-blended natural gas.

Facility Dominion Chesterfield CERC
Location Chesterfield County
Reg. No. 50396
Eng AMS

Total Emissions from each turbine including su/sd

Scenario 1: 3,240 hours on natural gas.

	CT ea	SU ea	SD ea	Total (4)	Total All
pollutant	TPY	TPY	TPY	TPY	TPY
PM	12.21	0.45	0.225	12.88	51.52
PM10	23.19	0.89	0.45	24.53	98.11
PM2.5	23.19	0.89	0.45	24.53	98.11
CO	18.23	91.42	38.05	147.70	590.81
NOx	37.78	13.08	4.95	55.81	223.22
SO_2	5.55	0.88	0.23	6.6529	26.61
VOC	5.19	16.20	7.80	29.19	116.75
H_2SO_4	3.72	0.59	0.15	4.470	17.88
Lead	0.0019	0.0001	0.0000	0.0021	0.0084
CO2-e	464,240.36	30,196.00	7,876.25	502,312.61	2009250.444

Scenario 2: 3240 hours on natural gas w/ up to 10% hydrogen

	CT ea	SU ea	SD ea	Total (4)	Total All
pollutant	TPY	TPY	TPY	TPY	TPY
PM	12.07	0.45	0.225	12.74	50.97
PM10	23.10	0.89	0.45	24.45	97.78
PM2.5	23.10	0.89	0.45	24.45	97.78
CO	18.13	91.42	38.05	147.60	590.38
NOx	37.26	13.08	4.95	55.29	221.15
SO_2	5.34	0.8750	0.004	6.22	24.88
VOC	5.35	16.20	7.80	29.35	117.40
H_2SO_4	3.73	0.59	0.004	4.32	17.29
Lead	0.0019	0.0001	0.0000	0.0021	0.0083
CO2-e	458,642.82	30,196.00	7,876.25	496,715.07	1986860.298

Scenario 3

	CT	SU	SD	Total each*	Total All
pollutant	TPY	TPY	TPY	TPY	TPY
PM	18.31	0.94	0.47	19.73	78.91
PM10	34.56	1.91	0.96	37.43	149.74
PM2.5	34.56	1.91	0.96	37.43	149.74
CO	18.46	131.64	43.65	193.75	774.99
NOx	46.98	18.52	7.48	72.98	291.92
SO_2	5.92	0.79	0.20	6.91	27.63
VOC	6.50	18.37	8.75	33.62	134.47
H_2SO_4	3.99	0.53	0.14	4.65	18.61
CO2-e	506,985.35	33,074.96	8,626.95	548,687.26	2,194,749

*Worst case annual emissions are based on worst case emissions from:
Startup and shutdown plus worst case emissions from any of the following operating sce
Scenario 1 - 3,240 hours on natural gas and 500 SUs and SDs on natural gas.
Scenario 2 - 3,240 hours on natural gas plus hydrogen and 500 SUs and SDs on natural
Scenario 3 - 750 hours on fuel oil plus 2,490 hours on natural gas + 380 SUs and SDs on

Facility Dominion Chesterfield CERC
Location Chesterfield County
Reg. No. 50396 **HAP Emissions from each turbine**
Eng AMS

Combustion Turbines

		2445 MMBtu/hr			2451.7 MMBtu/hr				
	NG w/ or w/o H	3240 hrs/year 2490 hrs/year		**Fuel Oil**	0 hrs/year 750 hrs/year		Worst case SU/SD		
Pollutant	**EF**	**Emissions**		**EF**	**Emissions**		**Emissions**	**MAX**	**MAX**
	(Lb/MMBtu)	**lb/hr**	**tpy**	**(Lb/MMBtu)**	**lb/hr**	**tpy**	**TPY**	**lb/hr**	**TPY**
1,3-Butadiene	4.30E-07	1.05E-03	1.70E-03	1.60E-05	3.92E-02	1.47E-02	5.10E-03	3.92E-02	2.11E-02
Acetaldehyde	4.00E-05	9.78E-02	1.58E-01				5.20E-02	9.78E-02	2.10E-01
Acrolein	6.40E-06	1.56E-02	2.53E-02				8.32E-03	1.56E-02	3.37E-02
Benzene	1.20E-05	2.93E-02	4.75E-02	5.50E-05	1.35E-01	5.06E-02	2.01E-02	1.35E-01	1.07E-01
Ethyl Benzene	3.20E-05	7.82E-02	1.27E-01				4.16E-02	7.82E-02	1.68E-01
Formaldehyde*	7.10E-04	5.53E-01	8.96E-01	2.80E-04	1.01E+00	3.79E-01	9.23E-01	1.01E+00	1.99E+00
Naphthalene	1.30E-06	3.18E-03	5.15E-03	3.50E-05	8.58E-02	3.22E-02	1.12E-02	8.58E-02	4.74E-02
PAH	2.20E-06	5.38E-03	8.71E-03	4.00E-05	9.81E-02	3.68E-02	1.30E-02	9.81E-02	5.65E-02
Propylene Oxide	2.90E-05	7.09E-02	1.15E-01				3.77E-02	7.09E-02	1.53E-01
Toluene	1.30E-04	3.18E-01	5.15E-01				1.69E-01	3.18E-01	6.84E-01
Xylenes	6.40E-05	1.56E-01	2.53E-01				8.32E-02	1.56E-01	3.37E-01

*All emission factors are from AP-42 Table except formaldehyde which is based on vendor performance data (controlled to 91 ppbvd@15% O_2 using dry low NOx combustion and oxidation catalyst).

AP-42 does not have emission factors for acetaldehyde, acrolein, ethylbenzene, propylene oxide, toluene or xylene from FO combustion.

METALS	NG w/ or w/o H			Fuel Oil			SU/SD		
Pollutant	**EF**	**Emissions**		**EF**	**Emissions**		**Emissions**	**MAX**	**MAX**
	(Lb/MMBtu)	**lb/hr**	**tpy**	**(Lb/MMBtu)**	**lb/hr**	**tpy**	**TPY**	**lb/hr**	**TPY**
Arsenic				1.10E-05	2.70E-02	1.01E-02	3.43E-03	2.70E-02	1.35E-02
Beryllium				3.10E-07	7.60E-04	2.85E-04	9.67E-05	7.60E-04	3.82E-04
cadmium				4.80E-06	1.18E-02	4.41E-03	1.50E-03	1.18E-02	5.91E-03
chromium				1.10E-05	2.70E-02	1.01E-02	3.43E-03	2.70E-02	1.35E-02
lead	4.89E-07	1.20E-03	1.94E-03	1.40E-05				1.20E-03	2.10E-03
manganese				7.90E-04	1.94E+00	7.26E-01	2.47E-01	1.94E+00	9.74E-01
mercury				1.20E-06	2.94E-03	1.10E-03	3.74E-04	2.94E-03	1.48E-03
nickel				4.60E-06	1.13E-02	4.23E-03	1.44E-03	1.13E-02	5.66E-03
selenium				2.50E-05	6.13E-02	2.30E-02	7.80E-03	6.13E-02	3.08E-02

Heavy metal emissions from natural gas combustion in turbines are neglible. So AP-42 §3.1 for turbines did not have emission factors for metals .

Facility	Dominion Chesterfield CERC
Location	Chesterfield County
Reg. No.	50396
Eng	AMS

Seven Black Start Generators ES-38, ES-39, ES-40, ES-41, ES-42, ES-43, ES-44

3500	kW	4694	hp
453.59	g/lb	500	hrs/yr operation
7000	Btu/hp-hr	137	MMBtu/kgal
137	MMBtu/kgal	33.73	MMBtu/hr HHV

			Uncontrolled		Permitted Emissions		
Pollutant	EF	unit	lb/hr	tons/yr	lb/hr ea	tons/yr ea	tons/yr all
PM	0.20	g/kW-hr	1.54	2.70	1.54	0.39	2.70
PM_{10}	0.23	g/kW-hr	1.80	3.15	1.80	0.45	3.15
$PM_{2.5}$	0.23	g/kW-hr	1.80	3.15	1.80	0.45	3.15
CO	3.5	g/kW-hr	27.01	47.26	27.01	6.75	47.26
NOx	4.48	g/kW-hr	34.57	60.49	34.57	8.64	60.50
SO_2	0.00154	lb/MMBtu	5.19E-02	0.09	0.0519	0.0130	0.09
VOC	1.92	g/kW-hr	14.81	25.93	14.82	3.7038	25.93
H_2SO_4	1.18E-04	lb/MMBtu	3.97E-03	0.01	3.97E-03	9.93E-04	0.01
CO_2	163.085	lb/MMBtu	5500.85	9626.48	5500.85	1375.21	9626.48
CH_4	0.00661	lb/MMBtu	0.22	0.39	0.22	0.06	0.39
N_2O	0.0013	lb/MMBtu	0.04	0.08	0.04	0.01	0.08
CO_2e	163.620	lb/MMBtu	5518.92	9658.10	5518.92	1379.73	9658.10

Notes:

Since no engine manufacturer has been chosen yet, the NSPS Standards for the pollutants below will ensure compliance with the NSPS, at a maximum.
CO, NOx & VOC from 40 CFR Part 60, Subpart IIII and 40 CFR Part 1042 Tier 2 standards.

The NOx/VOC standard is a combined limit of 6.4 g/kW-hr. The factors above assume a ratio of 70% NOx and 30% VOC.

PM filterable from 40 CFR 60, Subpart IIII and 40 CFR Part 1039 Tier 2

PM10 and PM2.5 filterable from NSPS III/40 CFR 1039 Tier 2 standard plus condensable PM from AP-42, Table 3.4-1 (0.20 + 0.033 = 0.233 g/kW-hr) .

SO_2 based on fuel sulfur content of 0.0015% (15 ppm)

H_2SO_4 is based on a 5% conversion of SO_2 to SO_3 and 100% conversion of SO_3 to H_2SO_4

GHG EF from 40 CFR Part 98, Table C-1

Facility Dominion Chesterfield CERC
Location Chesterfield County
Reg. No. 50396
Eng AMS

Seven Black Start Diesel Generators HAP Emissions

3500 kW			4694 hp			
453.59 g/lb			500 hrs/yr operation			
7000 Btu/hp-hr			137 MMBtu/kgal			
137 MMBtu/kgal			33.73 MMBtu/hr HHV			
			Emissions			
Pollutant	EF	unit	lb/hr ea	tons/yr ea	tons/yr all	
acetaldehyde	2.52E-05	lb/MMBtu	8.50E-04	2.12E-04	1.49E-03	
acrolein	7.88E-06	lb/MMBtu	2.66E-04	6.64E-05	4.65E-04	
benzene	7.76E-04	lb/MMBtu	2.62E-02	6.54E-03	4.58E-02	
formaldehyde	7.89E-05	lb/MMBtu	2.66E-03	6.65E-04	4.66E-03	
naphthalene	1.30E-04	lb/MMBtu	4.38E-03	1.10E-03	7.67E-03	
PAH	2.12E-04	lb/MMBtu	7.15E-03	1.79E-03	1.25E-02	
toluene	2.81E-04	lb/MMBtu	9.48E-03	2.37E-03	1.66E-02	
xylene	1.93E-04	lb/MMBtu	6.51E-03	1.63E-03	1.14E-02	

Note:
HAP emission factors from AP-42, Section 3.4, Tables 3.4-3 and 3.4-4

Facility Dominion Chesterfield CERC
Location Chesterfield County
Reg. No. 50396
Eng AMS

One Fuel Gas Heater
ES-37
Natural Gas

BTU Rating:	18.8	MMBtu/hr
Fuel Rating	0.0184	MMcf/hr
Process Throughput:	161.459	MMcf/yr
Fuel Sulfur Content:	0.40	gr/dscf
Heat Content:	1020.00	MMBtu/mmcf

Pollutant	Emission Factor lb/MMBtu	Reference	UNCONTROLLED EMISSIONS Hourly (lb/hr)	8760 hrs (ton/yr)	Thruput (ton/yr)	Control Technology	Control Eff. %	PERMIT EMISSION LIMITS (lb/hr)	(ton/yr)
PM	1.87E-03	(1)	0.04	0.15	0.15	None	0.00	0.04	0.15
PM10	6.99E-03	(1)	0.13	0.58	0.58	None	0.00	0.13	0.58
PM2.5	6.99E-03	(1)	0.13	0.58	0.58	None	0.00	0.13	0.58
CO	3.70E-02	(2)	0.70	3.05	3.05	None	0.00	0.70	3.05
NOx	1.10E-02	(2)	0.21	0.91	0.91	None	0.00	0.21	0.91
SO_2	1.20E-03	(3)	0.0226	0.10	0.10	None	0.00	0.02	0.10
VOC Total	5.00E-03	(1)	0.09	0.41	0.41	None	0.00	0.09	0.41
H_2SO_4	2.60E-04	(3)	0.0049	2.14E-02	2.14E-02	None	0.00	4.89E-03	0.02
CO_2	117.00	(4)	2200	9634	9634	None	0.00	2199.6	9634
CH_4	0.0022	(4)	0.041	0.182	0.182	None	0.00	0.041	0.182
N_2O	0.00022	(4)	0.004	0.018	0.018	None	0.00	0.004	0.018
CO_2-e	117.12	(6)	2202	9644	9644	None	0.00	2202	9644

Notes:

1. PM and VOC emissions from AP-42 Section 1.4, Table 2 (converted to lb/MMBtu)
2. NOx and CO factors based on ultra-low NOx burners: 9 ppmvd @ 3% O_2 and 50 ppmvd @ 3% O_2, respectively.
3. SO_2 and H_2SO_4 based on fuel sulfur content of 0.4 grains/100 scf annual average.
4. GHG emissions from EPA "Mandatory Reporting of Greenhouse Gases" FR Vol. 74, No. 209, Part 98 (October 2009)
5. Global Warming Potentials for GHG: CO_2 = 1; CH_4 = 28; N_2O = 265

Facility Dominion Chesterfield CERC
Location Chesterfield County
Reg. No. 50396
Eng AMS

HAP from Fuel Gas Heater ES-37

BTU Rating:	18.8	MMBtu/hr
Natural gas heat value	1020	Btu/scf
Fuel rating	0.0184314	mmcf/hr
Hours of operation	8760	hrs/yr

	EF	**Emissions**	
Pollutant	**lb/mmcf**	**lb/hr**	**TPY**
Acetaldehyde	3.10E-03	5.71E-05	2.50E-04
Acrolein	2.70E-03	4.98E-05	2.18E-04
Benzene	5.80E-03	1.07E-04	4.68E-04
Ethyl Benzene	6.90E-03	1.27E-04	5.57E-04
Formaldehyde	1.23E-02	2.27E-04	9.93E-04
Naphthalene	3.00E-04	5.53E-06	2.42E-05
Total PAH	4.00E-04	7.37E-06	3.23E-05
Propylene Oxide	5.30E-01	9.77E-03	4.28E-02
Toluene	2.65E-02	4.88E-04	2.14E-03
Xylene	1.97E-02	3.63E-04	1.59E-03
Hexane	4.60E-03	8.48E-05	3.71E-04
METALS			
Arsenic	2.00E-04	3.69E-06	1.61E-05
Beryllium	1.20E-05	2.21E-07	9.69E-07
cadmium	1.10E-03	2.03E-05	8.88E-05
chromium	1.40E-03	2.58E-05	1.13E-04
cobalt	8.40E-05	1.55E-06	6.78E-06
lead	5.00E-04	9.22E-06	4.04E-05
manganese	3.80E-07	7.00E-09	3.07E-08
mercury	2.60E-07	4.79E-09	2.10E-08
nickel	2.06E-06	3.80E-08	1.66E-07
selenium	2.40E-05	4.42E-07	1.94E-06

Notes:
Source of emission factors:
Lead: AP-42, Table 1.4-2 (July 1998)
Metals: AP-42, Table 1.4-4
All other HAP: Ventura County, CA
Air Pollution Control District AB2588 Combustion
Emission Factors (May 17, 2001)

Facility	Dominion Chesterfield CERC
Location	Chesterfield County
Reg. No.	50396
Eng	AMS

Fuel Oil Storage Tanks: VOC Emissions				Throughput	
Fuel Oil Storage Tank for Turbines		12,000,000	gallons	60,000,000	gallons
Black Start Generator Tanks (7)		24500	gallons	877800	gallons
		12,024,500	gallons	60,877,800	gallons
Losses(lbs)	3223.16 lbs/yr				
	1.6 tons/yr				

The source used Breeze TankESP Pro Version 5.2.0 to estimate emissions

Facility	Dominion Chesterfield CERC
Location	Chesterfield County
Reg. No.	50396
Eng	AMS

16 Electical Circuit Breakers CB-1

224	lb of SF_6/breaker
16	breakers
0.5%	leakage rate*
17.92	lb/yr leakage
0.00896	tpy SF_6
210.56	tpy CO_2-e (@ 23,500 GWP for SF_6)**

Leakage will be monitored by gas density gauges on the breakers

*leakage rate estimate provided by manufacturer
** GWP from Table A-1 of Appendix A of 40 CFR Subpart 98

Facility Dominion Chesterfield CERC
Fugitive GHG Emission Calculations Chesterfield County
50396

Gas Analysis

Constituent	MW	Quantity[a]	Density of Constituent Gases	Contribution to Overall Sample Density by Species	Quantity
	(g/g mole)	(mole %)	(g/l)	(g/l)	(weight %)
Methane	16	98.00%	6.424	6.295	96.31%
Ethane	30	0.00%	12.045	0.000	0.00%
Propane	44	0.00%	17.665	0.000	0.00%
Isobutane	58	0.00%	23.286	0.000	0.00%
n-Butane	58	0.00%	23.286	0.000	0.00%
Isopentane	72	0.00%	28.907	0.000	0.00%
n-Pentane	72	0.00%	28.907	0.000	0.00%
Hexanes+	86	0.00%	34.528	0.000	0.00%
Oxygen	16	1.00%	6.424	0.064	0.98%
Nitrogen	28	0.00%	11.242	0.000	0.00%
CO_2	44	1.00%	17.665	0.177	2.70%
TOTAL		100.0%	210.379	6.536	100.00%

Methane concentration in natural gas was assumed to be 98%; CO_2 concentration assumed to be 1%

Gas density 42,015 lb/MMcf (23.8 lb/scf per table B-23 of application?)
Molar density 0.4015 kmol/m^3

Emissions Calculations

Equipment Type	Emission Factor[1] (scf/hr/source)	Component Count	NG Leakage		Fugitive CH_4 Emissions			Fugitive CO_2 Emissions			Total Fugitive CO_{2e} Emissions		Fugitive VOC Emissions[2]	
			scf/year	lb/yr	lb/hr	tpy	CO_{2e} tpy	lb/hr	tpy	CO_{2e} tpy	lb/hr	tpy	lb/hr	tpy
Valves	0.027	640	151,373	6,360	0.70	3.06	85.76	0.02	0.09	0.086	19.60	85.84	2.83E-03	1.24E-02
Connector	0.003	334	8,778	369	0.04	0.18	4.97	0.00	0.00	0.005	1.14	4.98	1.64E-04	7.19E-04
Pressure Relief Valves	0.04	40	14,016	589	0.06	0.28	7.94	0.00	0.01	0.008	1.81	7.95	2.62E-04	1.15E-03
Maintenance			100,000	4,202	0.462	2.02	56.65	0.01	0.06	0.057	12.95	56.71	1.87E-03	8.19E-03
TOTAL					0.80	5.55	155.33	0.04	0.16	0.156	35.50	155.48	5.13E-03	2.25E-02

Notes:

1 - Based on 40 CFR 98, Table W-1a for Eastern United States

2 - Non-methane, non-ethane VOC content of natural gas is assumed to be 0.39% by weight (application).

Facility Dominion Chesterfield CERC
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	ES33		ES34		ES35		ES36		ES37		ES38, 39, 40, 41, 42, 43, 44		TK3-10		CB1		FUG1		Facility	
	Turbine		Turbine		Turbine		Turbine		Fuel Gas Htr		7 Black Start Gens		oil tanks		16 Circuit Breakers		Fugitive components		Totals	
pollutant	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr ea.	tpy	lb/hr	tpy		tpy		tpy	lb/hr	tpy
PM	24.00	19.73	24.00	19.73	24.00	19.73	24.00	19.73	0.04	0.15	1.54	2.70	--	--	--	--	--	--	106.84	81.76
PM10	45.00	37.43	45.00	37.43	45.00	37.43	45.00	37.43	0.13	0.58	1.80	3.15	--	--	--	--	--	--	192.72	153.46
PM2.5	45.00	37.43	45.00	37.43	45.00	37.43	45.00	37.43	0.13	0.58	1.80	3.15	--	--	--	--	--	--	192.72	153.46
CO	11.70	193.75	11.70	193.75	11.70	193.75	11.70	193.75	0.70	3.05	27.01	47.26	--	--	--	--	--	--	236.54	825.30
NOx	47.90	72.98	47.90	72.98	47.90	72.98	47.90	72.98	0.21	0.91	34.57	60.50	--	--	--	--	--	--	433.79	353.32
SO_2	4.50	6.91	4.50	6.91	4.50	6.91	4.50	6.91	0.02	0.10	0.05	0.09	--	--	--	--	--	--	18.39	27.82
VOC	6.70	33.62	6.70	33.62	6.70	33.62	6.70	33.62	0.09	0.41	14.82	25.93	0.37	1.6	--	--	0.01	0.02	130.59	162.44
H_2SO_4	3.00	4.65	3.00	4.65	3.00	4.65	3.00	4.65	0.005	0.02	0.004	0.007	--	--	--	--	--	--	12.03	18.64
Lead	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000	0.00	--	--	--	--	--	--	--	--	0.00	0.01

CO_2	399,823	463,764	399,823	463,764	399,823	463,764	399,823	463,764	6,599	28,903	5500.85	1375.21	--	--	--	--	0.04	0.16		1,885,335
CH_4	16.22	8.74	16.22	8.74	16.22	8.74	16.22	8.74	0.12	0.54	0.22	0.06	--	--	--	--	0.80	5.55		36
N_2O	3.24	1.21	3.24	1.21	3.24	1.21	3.24	1.21	0.01	0.05	0.04	0.01	--	--	--	--	--	--		5
SF_6	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	0.01	--	--		0
CO_2-e	401,136	548,687	401,136	548,687	401,136	548,687	401,136	548,687	2,202	9,644	5,519	9,658	--	--	--	211	0.0	155		2,214,417

Facility Dominion Chesterfield CERC
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Total HAP	Fuel Gas Heater ES-37		State Toxics Exemption Lvls		NSR Permit Exempt? Y or N	
	lb/hr	TPY	lb/hr	TPY	lb/hr	TPY
Acetaldehyde	5.71E-05	2.50E-04	8.91	26.1	Y	Y
Acrolein	4.98E-05	2.18E-04	0.02277	0.03335	Y	Y
Benzene	1.07E-04	4.68E-04	2.112	4.64	Y	Y
Ethylbenzene	1.27E-04	5.57E-04	17.919	62.93	Y	Y
Formaldehyde	2.27E-04	9.93E-04	0.0825	0.174	Y	Y
Naphthalene	5.53E-06	2.42E-05	2.607	7.54	Y	Y
PAHs	7.37E-06	3.23E-05				
Propylene Oxide	9.77E-03	4.28E-02	3.168	6.96	Y	Y
Toluene	4.88E-04	2.14E-03	18.645	54.665	Y	Y
Xylene	3.63E-04	1.59E-03	21.483	62.93	Y	Y
Hexane	8.48E-05	3.71E-04	11.616	25.52	Y	Y
					Y	Y
Arsenic	1.11E-05	4.84E-05	0.0132	0.029	Y	Y
Beryllium	6.64E-07	2.91E-06	0.000132	0.00029	Y	Y
cadmium	6.08E-05	2.66E-04	0.0033	0.00725	Y	Y
chromium	7.74E-05	3.39E-04	0.033	0.0725	Y	Y
cobalt	4.64E-06	2.03E-05	0.0033	0,00725	Y	Y
lead	2.76E-05	1.21E-04	0.0099	0.02175	Y	Y
manganese	2.10E-08	9.20E-08	0.33	0.725	Y	Y
mercury	1.44E-08	6.30E-08	0.0033	0.00725	Y	Y
nickel	1.14E-07	4.99E-07	0.066	0.145	Y	Y
selenium	1.33E-06	5.81E-06	0.0132	0.029	Y	Y

The simple cycle combustion turbines are subject to MACT Subpart YYYY, and the emergency fire pump and black start engines are subject to MACT Subpart ZZZZ, and, therefore, as per 9VAC5-60-300.C.4, are not subject to toxics review

Total Toxics

Facility Dominion Chesterfield CERC
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	Emission increase CERC	Significance Levels	Significant Increase?	Contemporaneous Netting				Net Increase	Significant Net Emiss. Increase?
				Coal Blrs Shutdown	Coal Ash Pond Proj	Benefic Use	Pipeline Heater		
pollutant	tpy	tpy	Y/N	-	+	+	+	+/-	Yes/No
PM	81.76	25	Yes	(277.75)	42.39	4.46	0.01	(149.13)	No
PM10	153.46	15	Yes	(221.96)	12.08	2.48	0.02	(53.92)	No
PM2.5	153.46	10	Yes	(43.99)	1.49	2.07	0.02	113.05	**Yes**
CO	825.30	100	Yes	(165.28)	0	18.41	2.94	681.37	**Yes**
NOx	353.32	40	Yes	(453.55)	0	3.74	3.50	(92.99)	No
SO_2	27.82	40	No	--	--	--	--	--	
VOC	162.44	40	Yes	(19.13)	0	3.07	0.19	146.57	**Yes**
H_2SO_4	18.64	7	Yes	(427.97)	0	0.02	0.02	(409.29)	No
Lead	0.01	0.6	No	--	--	--	--	--	
CO_2-e	2,214,417	75,000	Yes	(1,700,338)	0	2,317	3,819	520,215	**Yes**

Facility Dominion Chesterfield CERC
Location Chesterfield County
Reg. No. 50396
Eng AMS

Minor NSR permit applicability determination
Uncontrolled emissions from all units at 8760 hours/year

	ES33		ES34		ES35		ES36		ES37		ES38, 39, 40, 41, 42, 43, 44		TK3 and TK4-10		CB1		FUG1		Facility Total	Minor NSR project exemp lvl	Exempt Pollutant ?
	Turbine		Turbine		Turbine		Turbine		Fuel Gas Htr		7 Black Start Gens		oil tanks		16 Circuit Breakers		Fugitive components				
pollutant	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr all	tpy	lb/hr	tpy		tpy		tpy	tpy	tpy	Yes/No
PM	24.00	105.12	24.00	105.12	24.00	105.12	24.00	105.12	0.035156	0.153983	10.80	2.70	--	--	--	--	--	--	423.33	15	No
PM10	45.00	197.10	45.00	197.10	45.00	197.10	45.00	197.10	0.13	0.58	12.59	3.15	--	--	--	--	--	--	792.12	10	No
PM2.5*	45.00	197.10	45.00	197.10	45.00	197.10	45.00	197.10	0.13	0.58	12.59	3.15	--	--	--	--	--	--	792.12	6	No
CO*	83.10	363.98	83.10	363.98	83.10	363.98	83.10	363.98	0.70	3.05	189.05	47.26	--	--	--	--	--	--	1506.22	100	No
NOx	403.30	1766.47	403.30	1766.47	403.30	1766.47	403.30	1766.47	0.21	0.91	241.98	60.49	--	--	--	--	--	--	7127.30	10	No
SO_2	4.50	19.71	4.50	19.71	4.50	19.71	4.50	19.71	0.02	0.10	0.36	0.09	--	--	--	--	--	--	79.03	10	No
VOC*	9.27	40.59	9.27	40.59	9.27	40.59	9.27	40.59	0.09	0.41	103.71	25.93	3.68E-01	1.61158	--	--	5.13E-03	2.25E-02	190.31	10	No
H_2SO_4	3.00	13.14	3.00	13.14	3.00	13.14	3.00	13.14	0.005	0.02	0.03	0.01	--	--	--	--	--	--	52.59	6	No
Lead	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.00	--	--							0.02	0.6	Yes

*Note: Pollutants subject to PSD permitting are subject to more stringent requirements than those subject to minor NSR permitting (9VAC5-80-1100.H).

Air Permit Application for the Chesterfield Energy Reliability Center Project (CERC) Community Outreach Summary

Dominion began a broad range of community outreach activities in June 2023, including a mandatory informational briefing specific to the air permitting process conducted November 16, 2023. A public website was established, in both English and Spanish, with project information, an interactive map, and providing a project email address and phone number for receiving community feedback. From June 2023 through the end of March 2025, Dominion sent 12 project mailings totaling over 53,000 print materials, in both English and Spanish, to adjacent landowners and residents within a 3-mile radius of the Project to inform community members about the project, upcoming engagement opportunities, and directing them to the website and/or email address and phone number to provide feedback. From June 2023 through the end of April 2025, in addition to the November 16, 2023, mandatory informational briefing on the air permit, Dominion hosted 12 voluntary community open house meetings in varying locations, days of the week, and times. Additionally, Dominion held 22 daytime weekday "office hour" sessions open to community members for walk in discussions. Appendix H of the March 3, 2025, permit application contains an analysis of environmental justice and more information about outreach conducted.

Throughout its public outreach efforts, Dominion has employed strategies intended to proactively address the presence of EJ communities identified in their demographic screening and ensure equitable access to information and opportunity for feedback to all community members, regardless of socioeconomic classification. Dominion has ensured CERC project information is fully accessible to Spanish language speakers, through translated materials posted on the Company's project website and in included in project mailings, and furthermore, by providing a Spanish language translator at community meetings and other outreach events. Regarding the November 16, 2023, informational briefing for the air permit, Dominion also advertised the event on Radio Poder WBTK 1380AM to promote participation from the Hispanic community.

Regarding the 12 voluntary community open house meetings, Dominion provided variation in meeting location, format and timing, as well as serving food and bringing activities to occupy children at open houses events to maximize accessibility for working families. Dominion also scheduled a Saturday open house and daytime office hours (aka public availability sessions) to maximize accessibility, and supported a February 25, 2024, town hall event hosted by elected officials to discuss the CERC project.

CERC Project Community Outreach Meetings

Date	Type of Outreach	Location	Address
6/27/23	Community Meeting	Bellwood Elementary School	9536 Dawnshire Rd, North Chesterfield, VA 23237
8/15/23	Community Meeting	Bellwood Community Center	9010 Quinnford Blvd, North Chesterfield, VA 23237
11/16/23	Air Permit Informational Briefing	SpringHill Suites, Chester	12301 Redwater Creek Rd, Chester, VA 23831
12/14/23	Community Meeting	Dominion Energy Chesterfield Training Center	11501 Old Stage Road in Chester, VA
2/6/24	Office Hours	Office Hours (11:00-13:00)	11501 Old Stage Road in Chester, VA
2/7/24	Office Hours	Office Hours (11:00-13:00)	11501 Old Stage Road in Chester, VA
2/13/24	Office Hours	Office Hours (11:00-13:00)	11501 Old Stage Road in Chester, VA
2/14/24	Office Hours	Office Hours (11:00-13:00)	11501 Old Stage Road in Chester, VA
2/20/24	Office Hours	Office Hours (11:00-13:00)	11501 Old Stage Road in Chester, VA
2/21/24	Office Hours	Office Hours (11:00-13:00)	11501 Old Stage Road in Chester, VA
2/27/24	Office Hours	Office Hours (11:00-13:00)	11501 Old Stage Road in Chester, VA
2/28/24	Office Hours	Office Hours (11:00-13:00)	11501 Old Stage Road in Chester, VA
3/5/24	Office Hours	Office Hours (11:00-13:00)	11501 Old Stage Road in Chester, VA
3/6/24	Office Hours	Office Hours (11:00-13:00)	11501 Old Stage Road in Chester, VA
2/20/24	Community Meeting	CE Curtis Elementary School	3600 W Hundred Rd, Chester, VA 23831
2/29/24	Community Meeting	Bellwood Elementary School	9536 Dawnshire Rd, North Chesterfield, VA 23237
3/2/24	Community Meeting	Dominion Energy Chesterfield Training Center	11501 Old Stage Road in Chester, VA
9/3/24	Office Hours	Office Hours (11:00-13:00)	11501 Old Stage Road in Chester, VA
9/10/24	Office Hours	Office Hours (11:00-13:00)	11501 Old Stage Road in Chester, VA
9/17/24	Office Hours	Office Hours (11:00-13:00)	11501 Old Stage Road in Chester, VA
9/24/24	Office Hours	Office Hours (11:00-13:00)	11501 Old Stage Road in Chester, VA
10/1/24	Office Hours	Office Hours (11:00-13:00)	11501 Old Stage Road in Chester, VA
10/8/24	Office Hours	Office Hours (11:00-13:00)	11501 Old Stage Road in Chester, VA
9/5/24	Community Meeting	Hyatt Place, Chester	13148 Kingston Ave, Chester, VA 23836
9/10/24	Community Meeting	Bellwood Community Center	9010 Quinnford Blvd, North Chesterfield, VA 23237
9/17/24	Community Meeting	Varina Elementary School	2551 New Market Rd, Richmond, VA 23231
3/24/25	Community Meeting	Homewood Suites, Chester	12810 Old Stage Rd, Chester, VA 23836
3/25/25	Community Meeting	Bellwood Elementary School	9536 Dawnshire Rd, North Chesterfield, VA 23237
3/27/25	Community Meeting	Varina Elementary School	2551 New Market Rd, Richmond, VA 23231
3/25/25	Office Hours	Office Hours 1100-1300 at VPST for Community	11501 Old Stage Road in Chester, VA
4/1/25	Office Hours	Office Hours 1100-1300 at VPST for Community	11501 Old Stage Road in Chester, VA
4/8/25	Office Hours	Office Hours 1100-1300 at VPST for Community	11501 Old Stage Road in Chester, VA
4/15/25	Office Hours	Office Hours 1100-1300 at VPST for Community	11501 Old Stage Road in Chester, VA
4/22/25	Office Hours	Office Hours 1100-1300 at VPST for Community	11501 Old Stage Road in Chester, VA
4/29/25	Office Hours	Office Hours 1100-1300 at VPST for Community	11501 Old Stage Road in Chester, VA

CERC Project Community Outreach Mailings

Date	Type of Outreach	Description
6/5/23	Mailing	Letter, one-pager, and postcard mailed
6/13/23	Mailing	Postcard and one-page information sheet mailed
7/15/23	Mailing	Postcard mailed; reminder about open house
8/1/23	Mailing	Letter mailed; announcing air permit submittal
9/7/23	Mailing	Letter mailed; CERC & Coal Ash Update
9/27/23	Public Advertisement	Public Notice for 11/16 meeting; ran in RTD and Petersbrug Progressive
10/27/24	Mailing	Postcard mailed; reminder of 11/16 public briefing
11/7/24	Mailing	Postcard mailed; reminder of 11/16 public briefing
11/9/23	Radio Advertisement	Advertisement of 11/16 meeting; ran on Spanish-speaking radio station 11/9-11/16 (WBTK Radio Poder 1380AM)
11/30/23	Mailing	Letter mailed thanking for attending 11/16 meeting and inviting to 12/14 meeting
1/30/24	Mailing	Letter mailed; notification of office hours and upcoming open houses
2/12/24	Mailing	Postcard mailed; reminder on office hours and upcoming open houses
8/20/24	Mailing	Letter mailed; announcing site change & open house dates
3/4/25	Mailing	Letter mailed; announcing CPCN/Rider filing and open house dates

MEMORANDUM

DEPARTMENT OF ENVIRONMENTAL QUALITY
Office of Air Quality Assessments

1111 East Main Street, Richmond, VA 23219
22nd Floor **804/698-4000**

To: James Kyle, Air Permit Manager (PRO)

From: Robert Lute, Office of Air Quality Assessments (AQA)

Date: July 3, 2025

Subject: Air Quality Analysis – Chesterfield Energy Reliability Center

---

I. Project Background

Virginia Electric and Power Company, d/b/a Dominion Energy Virginia (Dominion, formerly d/b/a Dominion Virginia Power), is proposing to install the Chesterfield Energy Reliability Center (CERC or Project) at the existing Chesterfield Power Station (CPS) located at 500 Coxendale Road in Chesterfield County, Virginia. CERC will consist of four dual fuel simple-cycle combustion turbines (CT) firing primarily pipeline quality natural gas, as well as having the capability to fire No. 2 fuel oil with a maximum sulfur content of 15 ppm (fuel oil). Additionally, the CTs will be capable of operating on an advanced gaseous fuel blend consisting of natural gas with up to 10% hydrogen (H_2 fuel blend). CERC will also include one natural gas-fired fuel gas heater, seven diesel-fired emergency generators, fuel oil storage tanks, and circuit breakers.

The proposed Project is subject to the permitting requirements of Prevention of Significant Deterioration (PSD) and minor new source review. This memorandum discusses the air quality analysis relating to minor new source review. A discussion of the air quality analyses pertaining to PSD is under a separate memorandum.

As part of the application for the minor new source review permit, DEQ required an air quality analysis be performed that demonstrates that the projected air emissions from CERC will neither cause or significantly contribute to a violation of any applicable NAAQS for nitrogen dioxide (NO_2), sulfur dioxide (SO_2), particulate matter with an aerodynamic diameter less than or equal to 10 micrometers (PM-10), carbon monoxide (CO), and particulate matter having an aerodynamic diameter equal to or less than 2.5 microns (PM-2.5).

II. Modeling Methodology

The air quality modeling analysis conforms to 40 CFR Part 51, Appendix W - Guideline on Air Quality Models and was performed in accordance with the approved modeling methodology. The air quality model used was AERMOD (Version 24142). AERMOD is the preferred EPA-approved regulatory model for near-field applications and is also contained in Appendix W of 40 CFR Part 51.

Additional details on the modeling methodology are available in the applicant's June 2025 Article 6 air quality impact analyses report (Revision 3). The NAAQS results for CO and PM-2.5 are available in Tables 4-4 through 4-6 of the applicant's June 2025 PSD air quality impact analyses report (Revision 3).

III. Modeling Results

NAAQS Analysis

The NAAQS analysis included emissions from CERC and CPS, emissions from existing sources from Virginia, and representative ambient background concentrations. The results of the NAAQS analysis are presented in Table 1 and demonstrate compliance with the applicable NAAQS.

Table 1
NAAQS Analysis Results

Pollutant	Averaging Period	Total Modeled Concentration ($\mu g/m^3$)	Ambient Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	% of NAAQS
NO_2	1-hour	169.83	---(1)	169.83	188	90.34
NO_2	Annual	11.86	7.5	19.36	100	19.36
SO_2	1-hour	136.73	7.9	144.63	196	73.79
SO_2	3-hour	84.88	8.9	93.78	1,300	7.21
SO_2	Annual	4.32	0.8	5.12	26	19.69
PM-10	24-hour	32.73	24	56.73	150	37.82
CO	1-hour	5,569.81	1,610	7,179.81	40,000	17.95
CO	8-hour	3,613.40	1,380	4,993.40	10,000	49.93
PM-2.5	24-hour	11.97(2)	12.0	23.97	35	68.49
PM-2.5	Annual	2.34(2)	5.8	8.14	9	90.44

(1) Season and hour of day varying

(2) Concentration includes the contribution from secondary PM-2.5 formation.

Toxics Analysis

Per the application, the Project combustion sources are all subject to a National Emission Standard for Hazardous Air Pollutants (NESHAP) and thus exempt from the requirements of 9 VAC 5-60-300 et seq. by 9 VAC 5-60-300 C.4, while the remaining sources are below the applicable emission rate thresholds in 9 VAC 5-60-300 C.1. Therefore, the Project is exempt from Virginia's air toxics regulations and a toxics analysis is not required. However, Dominion voluntarily conducted a toxics analysis and the results of the analysis are contained in Tables 4-6 and 4-7 of their June 2025 Article 6 air quality impact analyses report (Revision 3).

MEMORANDUM

DEPARTMENT OF ENVIRONMENTAL QUALITY
Office of Air Quality Assessments

1111 East Main Street, Richmond, VA 23219
22nd Floor **804/698-4000**

To: James Kyle, Air Permit Manager (PRO)

From: Robert Lute, Office of Air Quality Assessments (AQA)

Date: July 3, 2025

Subject: PSD Air Quality Analyses – Chesterfield Energy Reliability Center

---

I. Project Background

Virginia Electric and Power Company, d/b/a Dominion Energy Virginia (Dominion, formerly d/b/a Dominion Virginia Power), is proposing to install the Chesterfield Energy Reliability Center (CERC or Project) at the existing Chesterfield Power Station (CPS) located at 500 Coxendale Road in Chesterfield County, Virginia. CERC will consist of four dual fuel simple-cycle combustion turbines (CT) firing primarily pipeline quality natural gas, as well as having the capability to fire No. 2 fuel oil with a maximum sulfur content of 15 ppm (fuel oil). Additionally, the CTs will be capable of operating on an advanced gaseous fuel blend consisting of natural gas with up to 10% hydrogen (H_2 fuel blend). CERC will also include one natural gas-fired fuel gas heater, seven diesel-fired emergency generators, fuel oil storage tanks, and circuit breakers.

The proposed Project meets the definition of major modification under 9 VAC 5 Chapter 80, Article 8 (Prevention of Significant Deterioration (PSD)) of the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution. The pollutants subject to PSD review are carbon monoxide (CO), particulate matter having an aerodynamic diameter equal to or less than 2.5 microns (PM-2.5), volatile organic compounds (VOC), and greenhouse gases (GHGs). As a result, PSD regulations require an air quality analysis be performed that demonstrates that the projected air emissions from CERC will neither cause or significantly contribute to a violation of any applicable National Ambient Air Quality Standard (NAAQS) or PSD increment. In addition, PSD regulations require that an additional impact analysis consisting of a soil and vegetation analysis, a growth analysis, and a visibility impairment analysis be conducted.

An analysis of the Project's impact on air quality and air quality related values (AQRVs) in any affected Class I area may also be required, contingent upon input from the Federal Land Managers (FLMs). The National Park Service (NPS) stated in an e-mail dated August 4, 2023, that an AQRV analysis will not be required for Shenandoah National Park. The United States Forest Service (USFS) and the United States Fish and Wildlife Service (FWS) did not require an AQRV analysis; therefore, only a Class I area analysis to assess compliance with the Class I PSD increments was required.

The following is a summary of the AQA's review of the required air quality analyses for CERC for both Class I and Class II PSD areas. The worst-case impacts from all operating loads, including startup and shutdown operations, are presented in this memorandum.

II. Modeling Methodology

The Class I and Class II air quality modeling analyses conform to 40 CFR Part 51, Appendix W - Guideline on Air Quality Models and were performed in accordance with their respective approved modeling methodology. The air quality model used for both Class I and Class II area analyses was AERMOD (Version 24142). AERMOD is the preferred EPA-approved regulatory model for near-field applications and is also contained in Appendix W of 40 CFR Part 51. AERMOD was also used as a preliminary screening model to determine the need for more detailed PSD increment modeling in the Class I area.

Additional details on the modeling methodology are available in the applicant's June 2025 PSD air quality impact analyses report (Revision 3).

III. Modeling Results

A. Class II Area – Cumulative Impact Modeling Analysis

The cumulative impact analysis consisted of separate analyses to assess compliance with the NAAQS for CO and PM-2.5 and the Class II PSD increment for PM-2.5 for the applicable averaging periods.

NAAQS Analysis

The NAAQS analysis included emissions from CERC and CPS, emissions from existing sources from Virginia, and representative ambient background concentrations. The results of the NAAQS analysis are presented in Table 1 and demonstrate modeled compliance with the applicable NAAQS.

The ambient background concentrations used are consistent with the recommendations in 40 CFR Part 51, Appendix W, and are conservatively representative of ambient air quality for the area near CERC. These data fulfill the preconstruction monitoring requirements in 40 CFR 51.166(m) and 52.21(m). See Appendix C of the June 2025 PSD air quality impact analyses report for additional information about the representativeness of the data.

Table 1
NAAQS Modeling - Cumulative Impact Results

Pollutant	Averaging Period	Total Modeled Concentration ($\mu g/m^3$)	Ambient Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	% of NAAQS
CO	1-hour	5,569.81	1,610	7,179.81	40,000	17.95
CO	8-hour	3,613.40	1,380	4,993.40	10,000	49.93
PM-2.5	24-hour	11.97 (1)	12.0	23.97	35	68.49
PM-2.5	Annual	2.34 (1)	5.8	8.14	9	90.44

(1) Concentration includes the contribution from secondary PM-2.5 formation.

PSD Increment Analysis

The 24-hour and annual PM-2.5 PSD increment analysis included emissions from CERC and CPS. Table 2 below presents the results of the analysis and shows that the 24-hour and annual PM-2.5 concentrations were below their applicable PSD increment.

Table 2
PSD Increment Modeling - Cumulative Impact Results

Pollutant	Averaging Period	Modeled Concentration ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)
$PM_{2.5}$	24-hour	3.87 (1)	9
	Annual	1.11 (1)	4

(1) Concentration includes the contribution from secondary PM-2.5 formation.

NAAQS and PSD Increment Analyses Conclusions

Based on DEQ's review of the NAAQS and PSD increment analyses, assuming DEQ's regional office processing the permit application approved all of the emission estimates and associated stack parameters for the modeled scenarios, the proposed Project does not cause or significantly contribute to a predicted violation of any applicable NAAQS or Class II area PSD increment.

Additional Impact Analysis

In accordance with the PSD regulations, additional impact analyses were performed to assess the impacts from CERC on visibility, vegetation and soils, and the potential for and impact of secondary growth. These analyses are discussed below.

Visibility

The proposed Project will result in a net decrease in visibility impairment pollutants of 592 tons. As a result, an improvement in visibility is expected near the proposed Project site. Visibility in the area near CERC will be protected by operational requirements, such as air pollution controls and clean burning fuels, and stringent limits on visible emissions, which will be incorporated into its air permit.

Vegetation and Soils

An analysis to assess impacts on vegetation and soils was conducted. The analysis compared maximum predicted concentrations against criteria contained in the EPA document *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (EPA, 1980)* as well as the secondary NAAQS. The secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. Table 3 shows the maximum modeled concentrations were all below the respective thresholds. As a result, no adverse impacts on vegetation and soils are expected.

Table 3
Comparison of Vegetation Sensitivity Thresholds to Maximum Modeled Concentrations

Pollutant	Averaging Period	Maximum Modeled Concentration ($\mu g/m^3$)	Sensitive Vegetation Threshold ($\mu g/m^3$)
CO	1-week(1)	3,613.40	1,800,000
PM-2.5	24-hour(2)	11.97(3)	35
Ozone	8-hour	0.0022 ppm	0.06 ppm

(1) Modeled 8-hour averaging concentration from the NAAQS analysis was conservatively used to represent the 1-week impact.

(2) Modeled 24-hour averaging concentration from the NAAQS analysis.

(3) Concentration includes the contribution from secondary PM-2.5 formation.

Growth

Several hundred temporary construction jobs will be created during the expected 32-month construction phase of the Project. Once CERC becomes operational, approximately 10 full-time staff will support the Project. It is assumed that individuals that already live in the region will perform a number of these jobs. Additionally, it is anticipated there should be no substantial increase in community growth or need for additional infrastructure. Therefore, no significant new emissions from secondary growth during the construction and operation phases of CERC are anticipated.

B. Class I Area Modeling Analysis

The FLMs are provided reviewing authority of Class I areas that may be affected by emissions from a proposed source by the PSD regulations and are specifically charged with protecting the Air Quality Related Values (AQRV) within the Class I areas. The closest Class I area to the proposed Project is the Shenandoah National Park (SNP). It is approximately 144 kilometers (km) from the proposed Project. The other Class I areas within 300 km of the proposed Project but located at a distance greater than 144 km are James River Face Wilderness Area, Swanquarter National Wildlife Refuge, Dolly Sods Wilderness Area, and Otter Creek Wilderness Area.

Modeling guidance contained in the *Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report – Revised (2010)* provides screening criteria for determining whether a source may be excluded from performing a Class I area AQRV modeling analysis. The NPS stated in an e-mail dated August 4, 2023, that an AQRV analysis will not be required for Shenandoah National Park. The United States Forest Service (USFS) and the United States Fish and Wildlife Service (FWS) also did not require an AQRV analysis.

An analysis to assess compliance with the Class I PSD increments for PM-2.5 was conducted using a ring of receptors at 50 km from the proposed Project, the maximum valid distance of AERMOD. As shown in Table 4, the maximum predicted ambient impacts for PM-2.5 (24-hour and annual averaging periods) were less than the applicable Class I increments. Therefore, the maximum predicted ambient impacts for PM-2.5 (24-hour and annual averaging periods) are also expected to be less than the increments at all Class I areas.

Table 4
Summary of Maximum Predicted Concentrations at 50 km from CERC

Pollutant	Averaging Period	Maximum Predicted Concentration from CERC at 50 km ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)
PM-2.5	24-hour	0.25[1]	2
PM-2.5	Annual	0.0073[1]	1

[1] Concentration includes the contribution from secondary PM-2.5 formation.

Summary of Class I Area Analysis

Based on DEQ's review of the Class I area modeling analyses, the proposed Project does not cause or significantly contribute to a predicted violation of any applicable Class I area PSD increment.

C. Other Modeling Considerations

Ozone

The impact on ozone from the CERC project's NO_X and VOC emissions was evaluated using the latest EPA modeling platform. The impact from the CERC project alone is 2.2 parts per billion (ppb) of ozone.

It is also important to evaluate the decrease in ozone, resulting from contemporaneous emissions reductions in ozone precursors (i.e., NO_X and VOC). Table 5 illustrates the net change in ozone, based on increases from the CERC project and decreases from CPS.

Table 5
Predicted Change in Ozone Concentration

Increase in Ozone Impact from CERC (ppb)	Decrease in Ozone Impact from Emissions Reductions (ppb)	Net Change in Ozone Concentration (ppb)
2.2	2.6	-0.4

The monitored ozone design value for the area is approximately 58 ppb for the period 2022 through 2024. A slight improvement in the ozone design value is expected and the area will continue to remain in compliance with the 8-hour ozone NAAQS of 70 ppb.