west virginia department of environmental protection

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Pursuant to §45-14-17.2

PRELIMINARY DETERMINATION/FACT SHEET

for the

MAJOR MODIFICATION

Dominion Energy Transmission, Inc.

Expansion of the

Mockingbird Hill Compressor Station

located near

Pine Grove, Wetzel County, West Virginia

Permit Application Number: R14-0033

Facility Identification Number 103-00006

Date: May 3, 2018

Contents

SUMMARY

Dominion Energy Transmission Inc. applied for a Major Modification Permit for expanding the Mockingbird Hill Compressor Station. This increase in natural gas compression capacity is required for DETI's existing pipeline system as it connects into the Atlantic Coast Pipeline. The upgrading of the existing pipeline system is referred to as the Supply Header Project (SHP). DETI proposed to install two (2) additional centrifugal compressors near the existing Mockingbird Hill Compressor Station.

The prime mover for these two compressors will be two simple cycle combustion turbines with a maximum power output rating of 20,500 hp each. The Hastings Complex consists of three natural gas compressors stations and a natural gas processing plant. The complex is classified as a major source under 45 CSR 14 (West Virginia's Prevention of Significant Deterioration Rule). The project represents a "significant increase of PM, PM_{10}, $PM_{2.5}$ and Greenhouse gas (GHGs) emissions and a significant net increase of PM, PM_{10}, $PM_{2.5}$ and Greenhouse gas (GHGs), which is just over 30 tons per year of PM, PM_{10}, and $PM_{2.5}$; and 194,675 tons of carbon dioxide equelivent (CO_2e) per year The DAQ has determined the best available control technology (BACT) for each pollutant, which is summarized in the following table.

Table #1 – Summary of Technologies as BACT for the Expansion of the Mockingbird Hill Compressor Station

Pollutant	**Combustion Turbines**	**Emergency Generator**	**Boiler**	**Equipment Leaks**
$PM/PM_{10}/PM_{2.5}$	Clean Fuel & Combustion Optimization	Good Combustion Practices	Clean Fuel & Tune-ups	N/A
GHGs[1]	Low Carbon Fuel & Combustion Optimization	Low Carbon Fuel & Combustion Optimization	Low Carbon Fuel & Combustion Optimization	Subpart OOOOa LDAR for GHGs & VOCs

[1]GHGs – Greenhouse gases, which consist of carbon dioxide, methane, nitrous oxides, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride.

Most of these new emissions will come from the two combustion turbines. The DAQ determined that the BACT limits at 0.02 lb/MMBtu for PM, PM_{10}, and $PM_{2.5}$; and 1.01 lb of CO_2e per hp-hr.

For this project to avoid a significant net increase of oxides of nitrogen, DETI proposed to replace the two existing reciprocating compressor engines at the Hastings Compressor Station with two new engines that meet the emission standards of Subpart JJJJ of Part 60, which has been permitted under Permit R13-3249A. Once DETI has completed the changes, the Hastings Complex will have the potential to emit only 115 tons per year of oxides of nitrogen and 183 tons of carbon monoxide per year. Therefore, the facility will no longer be a major source under the PSD permitting program.

ENGINEERING EVALUATION/FACT SHEET

B ACKGROUND INFORMATION

Application No.:	R14-0033
Plant ID No.:	103-00006
Applicant:	Dominion Energy Transmission, Inc. (DETI)
Facility Name:	Mockingbird Hill Compressor Station
Location:	Pine Grove
NAICS Code:	486210
Application Type:	Major Modification
Received Date:	September 17, 2015
Revised Application Received:	August 28, 2017
Engineer Assigned:	Edward S. Andrews, P.E.
Fee Amount:	$14,500.00
Fee Deposit Date:	October 7, 2015
Complete Date:	August 28, 2017
Due Date:	February 13, 2018
Applicant Ad Date:	October 7, 2015
Newspaper:	*Wetzel Chronicle*
UTM's:	Easting: 542.78 km Northing: 4,377.20 km Zone: 17
Description:	The application is for the expansion of the Mockingbird Hill Compressor Station for a natural gas pipeline segment which includes two combustion turbine/compressors, auxiliary generator, a small boiler, and two small tanks.

PUBLIC REVIEW PROCEDURES

45CSR13 and 45CSR14 require action items at the time of application submission and at the time a draft permit is prepared by the DAQ. The following details compliance with the statutory and accepted procedures for public notification with respect to permit application R14-0033.

Action Taken at Application Submission

Pursuant to §45-13-8.3 and §45-14-17. 1, DETI placed a Class I legal advertisement in the *Wetzel Chronicle* on October 7, 2017. On September 21, 2015, Mr. Joseph Kessler, P.E., the DAQ's PSD Coordinator, notified the respective Federal Land Mangers for the Wilderness Areas of Dolly Sods and Otter Creek; and the Shenandoah National Park by email of this proposed project. On September 21, 2015, Ms. Melanie Pitrolo, Air Quality Specialist for the U.S. Forest Service, notified the DAQ by email that the U.S. Forest Service will not be requesting any additional modeling to determine the Air Quality Related Values (AQRVs) for the affected Class I Area due to this proposed project.

Copy of the application and all relevant documents are available for review at the DAQ Headquarters in Charleston (Kanawha City) and at http://www.dep.wv.gov/daq/Pages/NSRPermitsforReview.aspx.

Actions Taken at Completion of Preliminary Determination

Pursuant to §45-13-8.5 and §45-14-17.4, upon completion (and approval) of the preliminary determination and draft permit, a Class 1 legal advertisement will be placed in the *Wetzel Chronicle* stating the DAQ's preliminary determination regarding R14-0033 and providing notice for a public meeting on May 30, 2018 from 6:00 pm to 8:00 pm in the cafeteria at the Short Line School in Pine Grove, WV.

Other Actions Related to this Project

To ensure the emission reductions at the Hastings Compressor (nearby surface site) that is to be used for this project to avoid being a “significant net emission increase” for oxides of nitrogen (NO_x), Dominion proposed Permit Application R13-3249A to make those reductions enforceable. Pursuant to §45-13-8.3 and §45-14-17. 1, Dominion Transmission Inc. placed a Class I legal advertisement in the Wetzel Chronicle on December 2, 2015, notifying the public of the submission of a permit application.

The replacement engine project at the Hasting Compressor Station is viewed as separate project because the emissions units are supporting different activities and can be operated independently of each other. Hastings Compressor Station is supporting the transmission of field gas to be delivered to the Hastings Extraction Plant, which will process the field gas into pipeline quality natural gas and other hydrocarbon products. The agency reviewed this application and with respect to the Mockingbird Hill Expansion Project as a contemporaneous change in emissions. The DAQ placed a Class I legal advertisement in the *Wetzel Chronicle* on May 10, 2017, notifying the public of its “intent to approve” Permit R13-3249A. After addressing comments received during the public comment period, the DAQ issued Permit R13-3249A on June 13, 2017.

FACILITY DESRIPTION

The Mockingbird Hill Compressor Station is located in Wetzel County, West Virginia. DETI operates the station to provide compression to support the transport of pipeline quality natural gas through interstate pipelines.

The Mockingbird Hill Compressor Station operates under Title V operating permit number R30-10300006-2011. The operating permit covers emission units at the Mockingbird

Hill Compressor Station, Lewis Wetzel Compressor Station, and the Hastings Compressor Station. These stations are separate surface sites that are located either adjacent to or on contiguous properties. DETI has classified all these surface sites as Source Industrial Code (SIC) of 4922 – Pipeline Operator of Natural Gas.

DETI is currently authorized to operate the following:

Hastings Compressor Station

- Two (2) Cooper GMXE-6 Reciprocating Engines (001-01, 001-02), each rated at 500 bhp;
- One (1) Generac Model QT080 Auxiliary Generator (002-06) rated at 128 bhp;
- One (1) Dehydration Unit Still (004-02) rated at 7.5 MMscf/day;
- One (1) Reboiler (005-06) rated at 0.55 MMBtu/hr;
- One (1) Enclosed Combustion Device (DEHY1) rated at 32.8 Mscf/day;
- One (1) Pipeline Heater (005-01) (HTR01)* rated at 10.0 MMBtu/hr; * HTR01 is physically located outside of the fence line for the Hastings Compressor Station and is used to prevent freezing of a transmission pipeline that undergoes a change in pipe diameter. DETI has listed this source in the facility's Title V Permit as the Carnegie Warehouse Gate Site.
- Seven (7) aboveground storage tanks (TK1 – TK7) of various sizes for the storage of fluids; and
- Various fugitive components related to the operation of the equipment at Hastings Compressor Station.

Lewis Wetzel Compressor Station

- One (1) Caterpillar Model 3612 Compressor Engine (001-03) rated at 3,550 bhp and equipped with a Catalytic Converter (CC1);
- One (1) Cummings Model KTA19G Auxiliary Generator (002-05) rated at 530 hp; and
- One (1) Bryan Model RV 450W-FDG Boiler (005-05) rated at 4.5 MMBtu/hr;

Mockingbird Hill Compressor Station

- Three (3) Capstone Microturbine Auxiliary Generators (002-02, 002-03, 002-04), each rated at 80 bhp;
- One (1) Cleaver Brook MTF 700-1250-60 Boiler (005-04) rated at 1.25 MMBtu/hr);
- One (1) Solar Taurus 60 Combustion Turbine (006-02) rated at 8,175 bhp; and
- Three (3) storage tanks of various sizes for the storage of fluids.

As part of this project, DETI seeks authorization for the construction and operation of the following emission units at the expansion site of the Mockingbird Hill Compressor Station:

- Two (2) Solar Titan 130 Combustion Turbines (CT-1, CT-2) each rated at 20,500 hp (ISO);
- One (1) Caterpillar Auxiliary Generator (EG-1) rated at 755 hp;
- One (1) Boiler (WH-1) rated at 8.72 MMBtu/hr;
- One (1) Accumulator Tank (TK-1) with a capacity of 1,000 gallons;
- One (1) Hydrocarbon Waste Tank (TK-2) with a capacity of 500 gallons; and
- Various operational natural gas releases associated with station components (FUG-01) and piping fugitive emissions (FUG-02) related to equipment proposed at the expansion site of the Mockingbird Hill Compressor Station.

DETI has been authorized to make the following changes at the Hastings Compressor Station under Permit R13-3249A:

- Removal of the two (2) Cooper GMXE-6 Reciprocating Engines (001-01 as EN01, and001-02 as EN02), each rated at 500 bhp;
- Replacement of the above engines by the installation of one (1) Ajax DPC-2803LE Reciprocating Engine (RICE-1) (EN04) rated at 547 bhp; and one (1) Ajax DPC-2802LE Reciprocating Engine (RICE-2) (EN05) rated at 384 bhp.

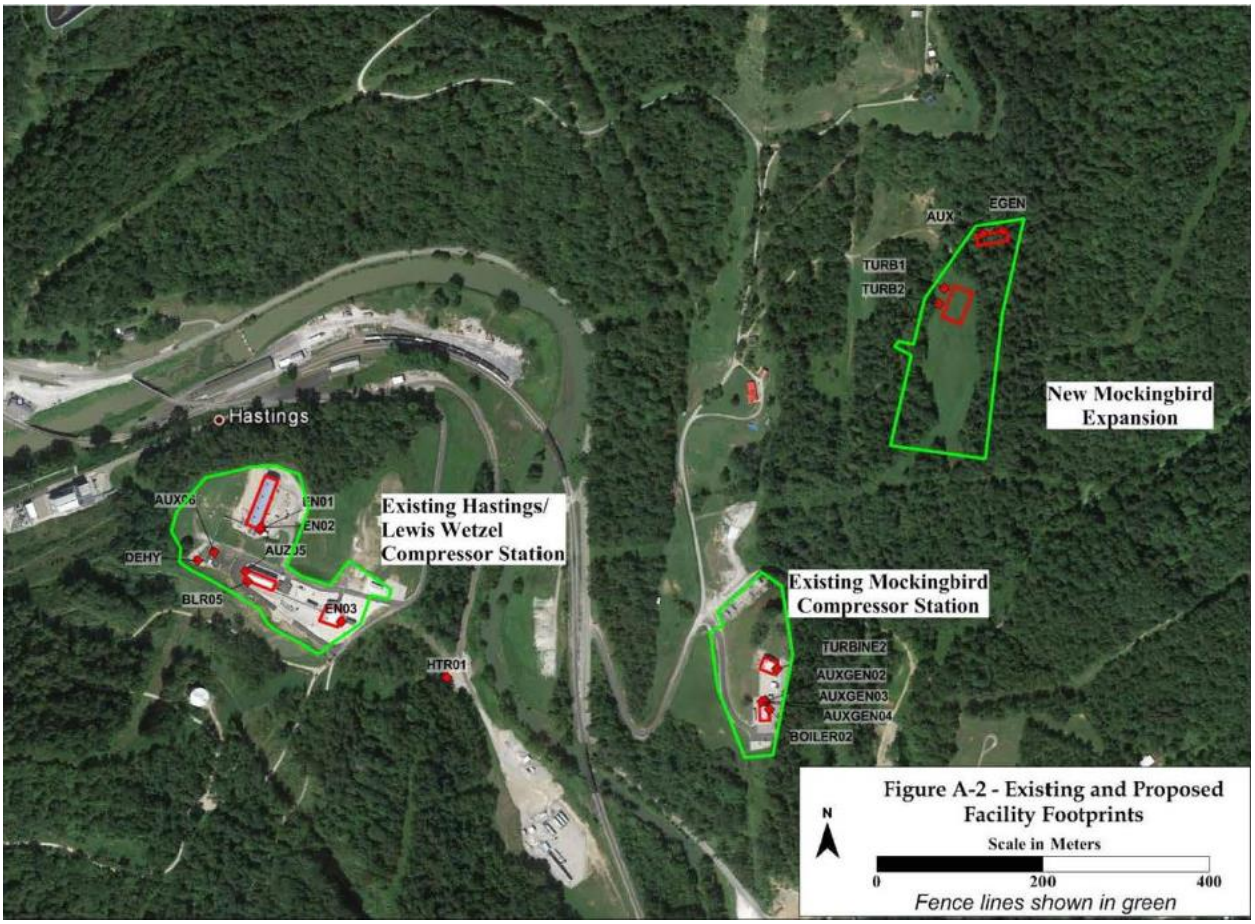

Figure 1– Location of Hasting/Lewis-Wetzel/Mockingbird Hill Compressor Stations

PROCESS DESCRIPTION

DETI has submitted this Major Modification Permit Application for the Mockingbird Hill Station to comply with the prevention of significant deterioration (PSD) permitting requirements of 45 CSR 14. Natural gas from the transmission pipeline is routed through this transmission station. The natural gas fueled internal combustion engines CT-01, and CT-02 provide the compression required for the transmission of natural gas along the Supply Header Project. The proposed turbines are Solar Turbines Model Titan 130-20502S combustion turbines configured with centrifugal compressors.

The expansion site of Mockingbird Hill Station will require an emergency generator (Caterpillar G3412C) with a capacity of 755 bhp to provide backup power during emergency situations. An 8.72 MMBtu/hr boiler (WH-01) will be installed to provide heat to the site's support structures. Produced liquids collected at the site will be stored in the accumulator tank (TK-1) until the liquid can be removed off-site by the tanker truck (LR-1) for proper disposal. A hydrocarbon (used oil) tank (TK-2) is proposed to be part of the modification at the Mockingbird Hill Station.

SITE INSPECTION

On July 13, 2016, the writer conducted a site visit of the actual proposed site for the expansion of the Mockingbird Hill Compressor Station. Mr. Laurence Labrie, and Mr. Joseph Stigall from Dominion Transmission Inc. accompanied the writer during this site visit. This visit included a visit to the Hastings Compressor Station and the proposed site.

The writer verified that the two Cooper GMXE-6 Engines (identified as EN01 and EN02) were physically at the station and in working order. At the time of the visit, both engines were in operation. There were no signs of construction activities detected at the proposed site for expansion of the Mockingbird Hill Compressor Station and Hastings Compressor Station during this inspection.

The following is a photograph taken from the South end facing due North of the proposed site.

Figure 2 Photograph of Proposed Expansion Date 7/13/2016

The nearest residential dwelling is approximately 700 feet North of the proposed site. There is an existing dwelling next to the current access road to the site and Mockingbird Hill Road. DETI has obtained this property with structures, which is approximately 45 acres. A new access road will be constructed from Mockingbird Hill Road to the site, which will cut straight across this acquired property. The writer determined that the proposed location is appropriate for these particular emission sources.

ESTIMATE OF EMISSIONS BY REVIEWING ENGINEER

Solar Combustion Turbines

DETI proposed to install two combustion turbines (CT) at the expansion site. These two CT will be equipped with Solar's SoLoNO$_x$ combustion technology, which is a lean pre-mix combustion technology, and an add-on oxidation catalyst to reduce carbon monoxide (CO) and volatile organic compound (VOCs) emissions. The SoLoNO$_x$ system optimizes performance of the turbine while minimizing the formation of oxides of nitrogen (NO$_x$), CO, and VOC emissions at typical conditions during normal operations. At very low load and cold ambient temperatures, the SoLoNO$_x$ system cannot be used to maintain flame stability of the CT. Thus, the CT is operated in non-SoLoNO$_x$ mode for these situations. This requires the combustion system to adjust the turbine controls, at these conditions, which causes these emissions to increase significantly.

DETI proposed no limitations on the two CT in the permit application. Thus, annual potential emissions were based on an operational schedule for normal operation at 100% load for 8,677 hours per year, non-SoLoNOx operation of 50 hours per year for low-temperature conditions and with 100 start-up and shutdown events (33 hours per year) per CT. For these non-SoLoNO$_x$ operating modes, Solar provided guidelines for its customers to predicts/determines these three pollutants from their CTs, which are NO$_x$, CO, and unburned hydrocarbon carbon (UHC).

UHC is fuel that did not get combusted in the combustion zone of the CT. The fuel that DETI has selected for these CTs is pipeline quality natural gas. This fuel is mainly made up of over 70% methane (typically over 90%) with the next main component being ethane which is about 5%. These two hydrocarbons are classified as non-VOCs under the Clean Air Act, which should not be counted towards an emission unit's potential to emit of VOCs. Beside these two hydrocarbons, the rest of the hydrocarbons in natural gas are classified as VOCs (i.e. propane, butanes, pentanes, etc.). Gas processors extracts (removes) out most of the VOC components prior to injecting the processed natural gas into a natural gas transmission pipeline system. Using an assumption that only 10% of the UHC is VOCs is appropriate for this case.

The pre-controlled emission rates during SoLoNO$_x$ mode at normal operating conditions are as follows (all emission rates are in terms of part per million dry volume (ppmvd) corrected to 15% oxygen (O_2) content).

- 9 ppmvd NO_x
- 25 ppmvd CO
- 2.5 ppmvd VOC (based on 10% of 25 ppmvd UHC).

The oxidation catalyst manufacturer provided data to indicate that the proposed add-on controls will provide an 80 percent reduction in CO, to achieve an emission rate of 5 ppmvd of CO corrected to 15% O_2. The catalyst will also control organic compound emissions which will reduce VOC, including formaldehyde, by 50 percent.

Solar classifies the operation of their turbines into five operating modes; normal operation, startup/shutdown, low-load, below zero, and extreme below zero. The emissions from the proposed turbine and existing one can vary significantly between these different operating modes. Solar refers to these modes as non-$SoLoNO_x$ modes except for normal operation, which is referred to as $SoLoNO_x$ Mode.

DETI intends to operate the CT at low-load during start-up and shut-down events. DETI plans on using an interlock system to prevent operation at low-load operation at all other times except during start-up and shut-down events.

DETI reviewed historic meteorological data from the previous five years for the region to estimate the worst-case number of hours per year under sub-zero (less than 0^0 F) conditions. The annual hours of operation during sub-zero conditions were conservatively assumed to be not more than 50 hours per year.

Normal Operation: Normal operating conditions is load above 50% with ambient temperatures above zero degrees Fahrenheit. The Solar's $SoLoNO_x$ is a lean premix, dry low NO_x emission combustion system, which works to minimize emissions generated from the combustion turbine. The system can maintain NO_x emissions to 9 ppm with the oxygen content corrected to 15% in this mode. Carbon dioxide (CO) and unburnt hydrocarbons (UHC) are maintained at 25 ppm with the oxygen level corrected to 15%. For these Titan turbines, NO_x and CO emission rates are 5.70 and 9.60 pounds per hour respectively before the oxidation catalyst. DETI assumed 10% of the UHC emissions as VOCs. Thus, the VOC rate from each turbine is 0.55 pounds per hour expressed as methane.

After the oxidation catalyst, CO emissions are reduced by at least 80% (5 ppmvd), which equates to 1.94 pounds per hour. The oxidation catalyst will destroy the VOC emission by at least 50% (1.25 ppmvd), which equates to 0.76 pounds per hour expressed as propane. Formaldehyde, which is the HAP generated by the combustion turbine in greatest quantity, is controlled to at least 0.25 pounds per hour.

Other criteria pollutants emitted are sulfur dioxide, particulate matter (PM), particulate matter less than 10 microns (PM_{10}), particulate matter less than 2.5 microns ($PM_{2.5}$), which includes the filterable and condensable fractions of PM, hazardous air pollutants (HAPs) (i.e. formaldehyde), and greenhouse gases (GHGs) (i.e. carbon dioxide, nitrous oxide, methane). DETI used emissions factors from Chapter 3.1 of AP-42 for SO_2, methane, and nitrous oxide. SO_2 potential to emit from each turbine was estimated to be 0.59 pounds per hour. Solar provided emission data on CO_2. Solar predicts the CO_2 rate from their Titan turbine to be 20,565 pounds per hour.

For PM/PM_{10}/$PM_{2.5}$, Solar does not recommend its customers to use AP-42 emission factors for these pollutants. Solar has reviewed PM test data of its combustion turbines and believes that the reference test methods were not developed or verified for low emission levels. Due to measurement and procedural errors, the measured PM rates may not be representative of actual particulate matter emitted. Therefore, Solar recommends its customers use a PM rate higher than 0.01 lb per MMBtu fuel input (Higher Heating Value) for natural gas turbines for permitting purposes. This recommendation is based on a sulfur content of the fuel of less than one grain per 100 cubic feet. DETI proposed a PM, PM_{10}, and $PM_{2.5}$ emission rate of 0.02 pounds per MMBtu, which includes the filterable and condensable portions of the particulate matter. This proposed PM/PM_{10}/$PM_{2.5}$ emission rate meets the Solar recommendations.

Startup/Shut Down: Startup and Shutdown events should take approximately 10 minutes per event (10 min. startup & 10 min. shutdown) or 20 minutes for a complete startup/shut down cycle. Solar has published Product Information Letter (PIL) 170 Revision 5 for customers to estimate emissions during startup/shut down events of their turbines. To determine the annual potential emissions, DETI used 100 complete events per year to determine the annual potential to emit for the turbine. CO emissions are 384.5 pounds per complete cycle with NO_x being only 3.1 pounds per cycle. UHC and carbon dioxide emissions are predicted to be 15.6 and 1,749 pounds per complete cycle respectively. DETI assumed that 20% of the UHC to be VOCs. Thus, the VOC rate during a startup/shutdown cycle was determined to be 13.20 pounds per cycle. It is assumed that the exhaust temperatures would not be sufficient for the oxidation reaction to maintain and therefore the VOC and CO emissions during these cycles would not be controlled.

Low-Load Operations: Low-load operation would be considered to be non-startup/shutdown modes with the turbine operating below 50% load (as determined by ambient temperatures). Solar provided guidance to estimate NOx, CO, and UHC emissions in PIL 167 Revision 4. The hourly rates at 50% load (61 MMBtu/hr) are 44.33 lb/hr of NO_x, 3,840 lb/hr of CO, and 22.0 lb/hr of VOCs. DETI plans on not operating the turbine in this mode.

Below Zero Operations: Cold weather operations would be considered to be when the turbine is operating at loads above 50% when ambient conditions are below zero degrees Fahrenheit. Solar provided an estimate of NOx, CO, and UHC emissions in PIL 167 Revision 4 for customers to estimate emissions during non-SoLoNO_x modes, which includes conditions below zero. For annual estimation purposes, DETI used 50 hours per year. CO emissions are 58.25 pounds per hour with NO_x emissions being 76.54 pounds per hour for operating the turbines during these conditions before being reduced by the catalyst. The VOC emissions also increased to 5 ppm, which equates to an hourly mass rate of 3.06 pounds per hour expressed as propane. The exhaust temperature entering the catalyst should still be sufficient to reduce CO and VOC emissions with the same reduction efficiencies at normal operating conditions. Thus, the CO emission rate after the catalyst is 11.65 pounds per hour with the VOC emission rate at 0.55 pounds per hour.

Extreme Below Zero Operations: In addition to regular below zero operations, although very limited, there are times when the ambient temperatures falls below negative twenty degrees Fahrenheit. In PIL 167 Revision 4, Solar has additional guidelines for determining emissions of NOx, CO, and UHC at these extreme conditions. For annual estimation purpose, DETI did not anticipate operating these combustion turbines during this condition based on the site historic meteorological data.

Venting (Blowdown)

DETI calculated emissions for venting of compressor (blowdowns) from startups and shutdowns. DETI projected that each turbine/compressor would go through 100 startup/shutdown cycles per year. The total amount of gas vented from these activities would be 7,579,500 cubic feet per year per compressor. Using the typical transmission gas composition, DETI estimated each compressor would vent from each startup/shutdown 3,468 tons per year of carbon dioxide equivalent (CO_2e) and 0.03 tons per year of VOC.

Boiler

DETI plans to install an 8.72 MMBtu/hr, natural gas fired boiler to supply heating of the surface structures during the heating season. DETI used emission factors from combustion analysis performed by ETI for NO_x, CO, and filterable particulate matter; Tables 1.4.1-1 and 1.4.1-3 of AP-42; and Subpart C of Part 98 to estimate emissions from the boiler. Presented in the following table is the estimate of emissions from the boiler.

Table #2 – Emissions from the Boiler (WH-01)			
Pollutant	**Emission Factor**	**Hourly Rate per Heater(lb/hr)**	**Annual Rate (TPY)**
$PM/PM_{10}/PM_{2.5}$ Filterable	1.9 lb/MMcf	0.016	0.070
PM Condensable Fraction	5.7 lb/MMcf	0.050	0.219
Total PM	7.6 lb/MMcf	0.065	0.28
Sulfur Dioxide (SO_2)	0.6 MMcf	0.01	0.04
Oxides of Nitrogen (NO_x)	84 lb/MMcf	0.72	3.15
Carbon Monoxide (CO)	50 lb/MMcf	0.43	1.88
Volatile Organic Compounds (VOCs)	5.5 lb/MMcf	0.047	0.21
Total Hazardous Air Pollutants (HAPs)	1.89 lb	0.03	0.13
Carbon Dioxide Equivalent* (CO_2e)	116.98 lb/MMBtu	1,020.07	4,467.91

The writer used Method 19 to back calculate the concentration of NO_x and CO from the provided emission factors, which yielded a NO_x concentration of 68 ppm with a CO concentration of 67 ppm. These concentrations are within the range of the expected concentration for these two pollutants.

Emergency Generator

The applicant used emissions data provided from the manufacturer and emission factors in Table 3.2-1 of AP-42 to determine the potential emissions due to the 755 hp engine. CO_2e emissions were determined in accordance with 40 CFR 98, Subpart C. Annual emissions were based on the engine operating for 500 hours per year.

Table #3 Emission from the Emergency Generator (EG-01)		
Pollutant	**Hourly Rate (lb/hr)**	**Annual Rate tpy**
Oxides of Nitrogen (NO_x)	3.33	0.83
Carbon Monoxide (CO)	2.79	0.70
Volatile Organic Compounds (VOCs)	0.76	0.19
Sulfur Dioxide (SO_2)	0.003	0.001
$PM/PM_{10}/PM_{2.5}$	0.0004	9.90E-5
Carbon Dioxide Equivalence (CO_2e)	643.00	161.00
Total Hazardous Air Pollutants (HAPs)	0.55	0.14
Formaldehyde (HAP)	0.45	0.11

Equipment Leaks

DETI has estimated the number of components by type of components for the proposed stations. Using the leakage factor by component type from the EPA Protocol for Equipment Leak Emission Estimate (EPA-453/R-95-017), DETI estimated the VOC emissions to be 0.85 tpy; CO_2e emissions to be 750.18 tpy, and HAPs emission to be 0.146 tpy.

Tanks

The proposed expansion will include the operation of two above-ground storage vessels to support operational activities. TK-1 – Accumulator Tank is a 1,000-gallon vessel which will accept collected fluids from the station's gas scrubbers, separators, and other gas equipment where pipeline liquids may be collected and need to be drained. The applicant used E&P Tanks to determine the potential flashing emissions and EPA TANKS 4.09D, to estimate breathing and working loses from TK-1. DETI also proposed a vessel to hold used oil generated at the site. This vessel is a 550-gallon tank, which is identified as TK-2. The following table is a breakout of the VOC emissions by vessel and by type of loss.

Table #4 VOC Losses from the Proposed Tanks

Tank	Capacity (gallons)/bbl	Annual Throughput (gallons/yr)	Breathing Loss (lb/yr)	Working Loss (lb/yr)	Flashing Loss (lb/yr)	Total VOCs (lb/yr)
Produced Fluids Tank T-001	1,000/24	12,500	0	0	700*	700.00
Used Oil Tank T-002	550/13	5,000	0.013	0.005	N/A	0.02
Total Emissions						700.02

* - E&P Tanks was used and yielded a summary value, which includes breathing, working, and flashing emissions from the vessel.

In reviewing the applicant's flashing losses from the produced fluids tank, the writer noted that it was predicting that 100% of the produced fluids were being flashed off. In addition, the inputs did not include any water. The writer attempted to re-evaluate the potential emissions from this vessel at the proposed station using ProMax 4.0 Build 18086.0 to predict the pipeline liquids collected in the inlet separator and gas scrubbers, which would be sent to TK-1. This effort did not produce results that would be considered to be representative of the conditions at the facility. The writer believes that the gas stream used in this prediction analysis was extremely dry and was not capable of producing liquids at high pressures.

Emissions from the proposed new sources are indicated in the following table.

Table #5 Summary of Emissions by Source for the Expansion Project								
Source	**NO_x (tpy)**	**CO (tpy)**	**PM_{10} (tpy)**	**$PM_{2.5}$ (tpy)**	**VOC (tpy)**	**SO_2 (tpy)**	**CO_2e (tpy)**	**HAPs (tpy)**
Solar Titan 130 (CT-1)	27.04	27.92	15.02	15.02	1.44	2.52	90,716.68	1.31
Solar Titan 130 (CT-2)	27.04	27.92	15.02	15.02	1.44	2.52	90,716.68	1.31
Emergency Generator (EG-01)	0.83	0.70	9.90E-5	9.90E-5	0.19	8.07E-4	161.00	0.14
Boiler WH-1	1.87	3.15	0.24	0.24	0.21	0.01	4,472.39	0.07
Tanks (TK-1 & TK-2)					0.35		5.13	0.001
Liquid Unloading (LR-1)					0.006		0	0
Blowdowns					8.90		7,853	1.53
Equipment Leaks					0.85		750.18	0.15
Totals	56.78	59.69	30.28	30.28	13.39	5.05	194,675.06	4.51

Because of the changes proposed in this application, the potential to emit for the entire facility, which includes the Hastings, Lewis-Wetzel, and Mockingbird Hill Compressor Stations will be 45.50 tpy of $PM/PM_{10}/PM_{2.5}$, 115.15 tpy of NO_x, 183.72 tpy of CO, 6.18 tpy of SO_2, and 48.32 tpy of VOCs.

REGULATORY APPLICABLILITY

West Virginia State Implementation Program (SIP) Rules

There are four West Virginia State Rules that apply to this proposed project.

45 CSR 2 - TO PREVENT AND CONTROL PARTICULATE MATTER AIR POLLUTION COMBUSTION OF FUEL IN INDIRECT HEAT EXCHANGERS

45 CSR 10 - TO PREVENT AND CONTROL AIR POLLUTION FROM THE EMISSION OF SULFUR OXIDES

45 CSR 13 - PERMITS FOR CONSTRUCTION, MODIFICATION, RELOCATION AND OPERATION OF STATIONARY SOURCES OF AIR POLLUTANTS, NOTIFICATION REQUIREMENTS, ADMINISTRATIVE UPDATES, TEMPORARY PERMITS, GENERAL PERMITS, PERMISSION TO COMMENCE CONSTRUCTION, AND PROCEDURES FOR EVALUATION

45 CSR 14 - PERMITS FOR CONSTRUCTION AND MAJOR MODIFICATION OF MAJOR STATIONARY SOURCES FOR THE PREVENTION OF SIGNIFICANT DETERIORATION OF AIR QUALITY

45 CSR 2 and 45 CSR 10 (Rules 2 & 10) establish emission standards and applicable requirements for certain types of stationary sources located in West Virginia. Rule 10 sets an allowable SO_2 emission rate for fuel burning units (boilers), manufacturing processes, and other process gas streams.

The proposed boiler is potentially subject to Rules 2 & 10. 45 CSR §2-11.1. and 45 CSR §10-10.1. excludes units with a heat input of less than 10 MMBtu/hr from Sections 4, 5,6, 8 and 9. of Rule 2 and Section 3 and 6 of Rule 10. Thus, the proposed unit would only be subject to the visible emission standard of 45 CSR §2-3.1., which is a 10 percent opacity limit.

The proposed turbines and emergency generator have substantive federal requirements under 45 CSR §13-2.24.a. that makes these units "stationary sources" under Rule 13. 45 CSR §13-5.1 requires stationary sources to obtain a permit pursuit to this rule prior to installing the emission unit.

The applicant submitted a complete application, paid the Rule 13 permit application filing fee, which includes the New Source Performance Standard and the major modification fees, and published a legal ad in the *Wetzel Chronicle* (local newspaper in Wetzel County, WV) on October 7, 2015.

West Virginia adopted the U.S. EPA Prevention of Significant Deterioration (PSD) program by establishing 45 CSR 14. The main function of this program is to allow economic growth while ensuring that the local ambient air quality and Class I Areas (Wilderness Areas and National Parks) are not adversely affected from major sources of air pollution. Under the Clean Air Act, a Class I Area is one in which visibility is protected more stringently than under the National Ambient Air Quality Standards; includes national parks, wilderness areas, monuments, and other areas of special national and cultural significance.

This program requires construction of major sources and major modifications of major sources to undergo review to ensure that the Best Available Control Technology (BACT) is installed, and used to limit emissions of criteria pollutants, as well as to conduct a scientific analysis to ensure that the impact from such growth does not adversely affect the subjected areas.

Rule 14 defines a "major modification" as a "physical change" or "change in method of operation" that results in a "significant emissions increase and significant net emission increase" of a major source.

Under 45 CSR §14-2.43.b., a natural gas compressor station has to have a potential to emit of two hundred and fifty (250) tons per year or greater of any regulated New Source Review (NSR) pollutant to be classified as a major source. At this time, DETI's Hastings Compressor Station Complex, which includes the Lewis-Wetzel and Mockingbird Hill Compressor Stations has the potential to emit of 264 tons of oxides of nitrogen per year, which classifies the collection of the Hastings, Lewis-Wetzel and Mockingbird Hill Compressor Stations as an existing major source under Rule 14.

The proposed changes that DETI has outlined in this application are classified as a "physical change" under Rule 14. Therefore, the rule required DETI to determine if the potential emissions represent a "significant emissions increase and a significant net emission increase" of a regulated pollutant under the rule. This is summarized in the following table.

Table #6 –Summary of Project with Respect to the Significance Threshold Levels			
Pollutant	**PTE of Expansion Project**	**PSD Significance Threshold Level (tpy)**	**Does the Project Represent a Significant Increase in Emissions**
	TPY	**TPY**	**Yes /No**
PM	30.28	25	**Yes**
PM_{10}	30.28	15	**Yes**
$PM_{2.5}$	30.28	10	**Yes**
NO_x	56.79	40	**Yes**
CO	59.69	100	No
SO_2	5.05	40	No
VOCs*	13.39	40	No

* - Fugitives are not included for this source category (45 CSR §14-2.43e.)

Since the project has a potential to emit beyond the significant threshold for PM, PM_{10}, $PM_{2.5}$ and NO_x, contemporaneous changes were identified to determine if the expansion project would represent a "significant increase and significant net emissions increase." DETI identified two previous projects that have occurred within the past 10 years at the Hastings Complex, which should be considered as contemporaneous changes. These projects are the construction of the Lewis-Wetzel Compressor Station in 2012 (Permit R13-2870), and the modification of the dehydration unit at the Hastings Compress Station in 2017 (Permit R13-3249). DETI proposed to replace the two-existing compressor engines at the Hasting Compressor Station in 2017 as well (Permit R13-3249A).

The Lewis-Wetzel Compressor Station began operations in 2012. The emission units at the station are covered by Permit R13-2870, which includes one Caterpillar Model 3613 (001-03) rated at 3,550 bhp with a catalytic converter (CC1); one (1) Cummings Model KTA19G Auxiliary Generator (002-05) rated at 530 bhp; one (1) Bryan Model RV 450W-FDG Boiler (005-05) rated at 4.5 MMBtu/hr.

DETI replaced the existing natural gas dehydration unit and associated control device (enclosed combustion device) at the Hastings Compressor Station. The replacement dehydration unit began operation in 2017. This replacement project called for the replacement of the existing glycol dehydration unit and flare with a new glycol dehydration unit rate to handle 7.5 million standard cubic feet per day of wet natural gas by using one (1) Diverse Energy Systems reboiler rated at 0.55 MMBtu/hr with one (1) Questor Technologies Q50 enclosed combustion device. These emission units were permitted under R13-3249.

In addition to these past contemporaneous changes, DETI proposed to retire in place the two (2) existing Cooper GMXE-6 compressor engines (001-01 and 001-02) at the Hastings Compressor Station. DETI has planned to install one (1) Ajax Model DPC-2803 LE (EN04) rated at 542 Bhp and one (1) Ajax Model DPC-2802-LE (EN05) rated at 347 bhp. These replacement engines have been permitted under Permit R13-3249A.

DETI used the emission data from operating year 2013-2014 to develop the past actual emissions for EN01 and EN02. The following table is the PM and NOx emissions for EN01 and EN02 from 2013-2014 and baseline emissions, which is the average of emissions over two years.

Table #7 – Summary of Emission for Engines 001-01 and 001-02 from 2013-2014

Pollutant	**EN01 - 2013 (tpy)**	**EN01 – 2014 (tpy)**	**EN02 – 2013 (tpy)**	**EN02 2014 (tpy)**	**Baseline Emissions for EN01 (tpy)**	**Baseline Emissions for EN02 (tpy)**
NO_x	98.13	101.52	88.07	100.74	99.83	94.41
PM	0.72	0.73	0.64	0.70	0.73	0.67
PM_{10}	0.72	0.73	0.64	0.70	0.73	0.67
$PM_{2.5}$	0.15	0.15	0.13	0.15	0.15	0.14

The same process was repeated to obtain baseline emissions for the reboiler of the dehydration unit that was replaced. The baseline emissions were based on 2013 and 2014 operating years. The following table is the summary of the contemporaneous emission changes (increases and decreases) with the proposed project.

Table #8 – Summary of Net Emission Changes for the project							
Pollutant	**Expansion Project (tpy)**	**Increases due to Lewis-Wetzel CS (tpy)**	**Emission of new Dehy @ Hastings CS(tpy)**	**Reductions of replaced Dehy (tpy)**	**Emissions from EN04 & EN05 (tpy)**	**Reductions from 001-01 & 001-02 (tpy)**	**Net Change in Emissions (tpy)**
NO_x	56.11	19.63	1.44	- 0.60	8.58	-194.24	-109.08
PM	30.03	0.06	0.06	- 0.02	1.74	-1.40	30.47
PM_{10}	30.03	0.06	0.06	- 0.02	1.74	-1.4	30.47
$PM_{2.5}$	30.03	0.06	0.06	-0.02	1.74	-0.29	31.58

The net changes indicate that the project would result in a net decrease of just over 109 tons of NO_x emissions per year. However, the net change in PM, PM_{10}, and $PM_{2.5}$ emissions still result in an increase of over 30 tons per year for each of the subsets of particulate matter. As such, PSD permitting is triggered for these pollutants only (PM, PM_{10}, $PM_{2.5}$).

Because the project represents a "significant emission increase and significant net emissions increase" of an NSR Pollutant, then DETI is required to determine if the project is significant for greenhouse gases (GHGs). The expansion project by itself represents an increase of 194,539 tons per year of carbon dioxide equivalents. This potential to emit of GHGs is greater the significance threshold of 75,000 tons per year of CO_2e and therefore the project is significant for GHG in accordance with 45 CSR §14-2.80.d.

DETI's proposed expansion site of the Mockingbird Hill Compressor Station is adjacent and/or contiguous to an existing major source. The proposed project will result in a "significant emissions increase and significant net emissions increase" for PM, PM_{10}, $PM_{2.5}$ and GHGs. Therefore, a major modification permit application requires an analysis to ensure implementation of the Best Available Control Technology (BACT) is established and justified for each pollutant with a significant net emissions increase. A technical review has been performed to investigate BACT decisions for the each of these pollutants that have been determined by various permitting authorities across the U.S. to satisfy BACT requirements.

This application triggered the minor source baseline for $PM_{2.5}$ on February 7, 2017 for Wetzel County, West Virginia.

Federal Regulations

New Source Performance Standards (NSPS)

New Source Performance Standards (NSPS) apply to certain new, modified, or reconstructed sources meeting the criteria established in 40 CFR 60.

The boiler is rated with a heat input of 8.72 MMBtu/hr. The definition of affected source in Subpart Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units) is units between 10 MMBtu/hr and up to 100 MMBtu/hr. Thus, the proposed boiler is not an affected source and is not subject to the standards under Subpart Dc.

The two Titan-130 combustion turbines are to be used to drive two compressors that are used to support the delivery of pipeline quality natural gas through a pipeline system. Subpart OOOOa (Standards of Performance for Crude Oil and Natural Gas Production) establishes standards for certain process equipment at oil and natural gas production sites. This regulation defines sites from the wellhead and the point of custody transfer to the natural gas transmission and storage segment. The Mockingbird Hill Compressor is downstream of the custody transfer point of DETI's transmission system. Therefore, the proposed natural gas compressors are not affected sources and not subject to the performance standards of Subpart OOOOa.

The produced fluids tank (T-001) will receive pipeline liquids from the collection point of the pipeline system located within the station. This tank may be subject to Subpart OOOOa if the VOC potential is 6 tons per year or greater (40 CFR 60.5365(e)). Potential emissions from the tank must include flash, working, and breathing losses. The applicant's analysis indicts the vessel has a potential of 0.35 tons per year of VOCs which is less than the applicability threshold of six (6) tons per year.

Subpart JJJJ

DETI proposed a new Caterpillar G3412C spark-ignition (SI), four (4) stroke lean burn (SLB), reciprocating internal combustion engine (RICE) for the expansion site to provide electric power if local electric utility service is interrupted. This engine meets the applicability criteria as defined in 40 CFR 60.4230(a)(4)(iv) and therefore, the engine is an affected source under the regulation.

Pursuant to 40 CFR §60.4233(e): "Owners and operator of stationary SI RICE with a maximum engine power greater than or equal to 75 kW (100 hp) (except gasoline and rich burn engines that use liquefied petroleum gas (LPG)) must comply with the emission standards in Table 1 to this subpart for their stationary SI ICE." As proposed DETI's emergency generator is greater than 100 hp. The engine must comply with the emission standards under Table 1 for "Emergency $\geq$ 130hp:" NO_x – 2.0 g/hp-hr; CO – 4.0 g/hp-hr; and VOC – 1.0 g/hp-hr.

DETI provided site specific technical data on the specific model engine that indicates that the proposed engine is capable of achieving the applicable emission standards for an emergency RICE. The provided data was generated using Caterpillar Gas Engine Rating Pro Version 6.0400.

Since this engine is rated for more than 500 hp and is not certified to be a compliant engine by the manufacturer, DETI will be required to follow the compliance option under 40 CFR §60.4243(b)(2)(ii). This option will require DETI to conduct an initial compliance test within 180 days after startup and subsequent tests every three (3) years, thereafter. In addition to these tests, DETI is required to keep a maintenance plan and records of conducted maintenance of the engine.

The regulation allows for up to 100 hours of operation of the engine for non-emergency situations (i.e. readiness checks, maintenance tests, etc) except for peak-shaving or other situations that the engine would operate to generate income for the facility. DETI is required to keep records of operating hours and the purpose of the operation.

Subpart KKKK

U.S. EPA has promulgated an NSPS for stationary combustion turbines constructed, modified, or reconstructed after February 18, 2005, in Subpart KKKK. Subpart KKKK applies to combustion turbines with a peak heat input of 10 MMBtu/hr and greater. The proposed Solar Titan 130 turbines are rated at 173.49 MMBtu/hr (at 0^0 F). Therefore, the purposed turbines are affected sources under this subpart.

Sources subject to Subpart KKKK are exempt from the requirements of Subpart GG (NSPS for combustion turbines constructed/modified/reconstructed after October 3, 1977).

This subpart establishes emissions standards for NO_x and SO_2. These turbines would be limited to 0.060 lb of SO_2 per MMBtu/hr of heat input. The turbines will be burning pipeline quality natural gas with a maximum sulfur content of 20 grains per 100 standard cubic feet of gas. Under 40 CFR §60.4365, a source is exempt from monitoring fuel sulfur content if the source burns natural gas that is covered by a transportation agreement (Federal Energy Regulatory Commission tariff limit) with a maximum of 20 grains of sulfur per 100 standard cubic feet of gas (40 CFR §60.4365(a)).

According to DETI's FERC Gas Tariff, Fourth Revised Volume No.1 (Section 2.2[A] of the General Terms and Conditions), except as otherwise provided, all natural gas delivered to DETI at Receipt Point(s) and all natural gas delivered by DETI at the Delivery Point(s) shall conform to the following specifications: Hydrogen Sulfide and Total Sulfur - The gas shall not contain more than ¼ grain of hydrogen sulfide per one hundred (100) cubic feet and not more than twenty (20) grains of total sulfur per one hundred (100) cubic feet of gas. DETI's Gas Tariff meets this exemption.

40 CFR §60.4325 establishes NO_x standards for affected units as specified in Table 1 of Subpart KKKK. The proposed Titan 130 turbine is a new turbine firing natural gas with a heat input of greater than 50 MMBtu/hr and less than 850 MMBtu/hr. In this subcategory, these turbines are subject to a NO_x standard of 25 ppm at 15 percent oxygen (O_2) content or 150 nanograms /Joule of useful output. The selected turbines are equipped with a dry low NO_x emission combustion system, known as SoLoNO$_x$™, which has been developed to provide the lowest emissions possible during normal operating conditions. Solar Taurus (manufacturer) predicts the NO_x emissions with the SoLoNO$_x$™ combustion controls from the turbine to be 9 ppm when the ambient temperatures are at or above 0^0 F.

There are alternative standards for units operating at less than 75 percent of peak load or when operating temperatures are less than 0^0 F. The alternative limit of 150 ppm at 15% O_2 and is listed in Table 1 to Subpart KKKK. The manufacturer predicts that the NO_x rate for the proposed turbines would increase up to 120 ppm for subzero operations. For low load operations, the manufacturer predicts the NO_x concentrations to increase slightly to 70 ppm for loads at or less than 50% of peak output and 50 ppm at idle conditions. The proposed turbines are capable of meeting the NO_x limitations under this subpart at normal and other than normal conditions.

This subpart requires sources to use one of two options in monitoring compliance with the standard, which are testing or a continuous monitoring system. Sources can conduct testing every year and reduce the subsequent testing to every two years if the NO_x results are at or less than 75% of the standard, which equates to 18.75 ppm for these two turbines. The applicant has elected to use the testing option at this time. The permit will be structured on the 9 ppm as the short term limit, which is 36 % of the applicable limit, for the short term limit, with initial testing and subsequent testing every two years. Under the subpart, sources electing to conduct testing are only required to submit test reports of the results in lieu of submitting excess emissions and monitor downtime reports in accordance with 40 CFR §60.7(c).

Subpart OOOOa

This regulation covers certain emission units associated with crude oil and natural gas facilities, which include packing seals on compressors; tank storing accumulated of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and equipment leaks.

For tanks with a VOC potential greater than 6 tons per year, the regulation requires these vessels to install controls that effectively reduce this potential by at least 95%. DETI used E&P Tanks to predict the VOC potential of TK-1, which includes the working, breathing, and flashing emissions for storing the accumulated pipeline liquids collected at the station. This model predicted the potential VOC from TK-1 at 0.35 tons per year, which is less than the control threshold of 6 tons per year. Even though the prediction is less than the threshold, DETI is still required to measure the vessel actual production rate during the first 30 days the vessel is in service and determine the vessel potential based on the measured production rate.

This regulation establishes a GHG and VOC standard for centrifugal compressors using wet seal fluid. DETI proposed two centrifugal compressors using dry seals, which is common for compressors handling transmission quality natural gas. Thus, this standard does not apply to the DETI proposed centrifugal compressors.

This regulation establishes a GHG and VOC emission standard for equipment leaks at compressor stations. 40 CFR §60.5365a(j) makes the collection of fugitive emission components at a compressor station an affected source under Subpart OOOOa. Further, 40 CFR 60.5365(a)(j) defines a "modification" as either (1) an additional compressor installed at a station or (2) one or more compressors is replaced with a net increase in horsepower.

The collection of fugitive emission components at the expansion site is an affected source according to 40 CFR §60.5365a(j). The expansion site and existing Mockingbird Hill Compressor Station are located within 0.25 miles of each other. These stations may not share actual equipment but have the same function, which is to assist in transporting natural gas through the same pipeline segment (same plant functionally). Therefore, this project is modifying the compression capacity of the Mockingbird Hill Compressor Station as defined in Subpart OOOOa. The existing fugitive emission components at the Mockingbird Hill Compressor Station are affected sources and subject to the GHG and VOC emission standard for equipment leaks.

DETI will be required to develop a monitoring plan and conduct the initial monitoring survey within 60 days after startup of the new compressors and subsequent surveys shall be conducted on a quarterly basis thereafter. The standard requires detected leaks to be repaired as soon as practicable, but no later than 30 days. If a repair is technically infeasible and would require a compressor station shutdown then the repair may be delayed until the next scheduled shutdown or within 2 years, whichever occurs first.

Regulations under Part 63

The three (3) surface sites that make up the facility are natural gas compressor stations. Under the RICE MACT (Subpart ZZZZ), Turbine MACT (Subpart YYYY), and Boiler MACT (Subpart DDDDD), the definition of "*major source*" of HAPs is not the same as defined in 40 CFR §63.2 for oil and gas facilities. In fact, the definition of *"major source"* as defined in each of these regulations is differently phrased.

The Turbine MACT clearly notes under the definition of "natural gas transmission and storage facility" that the aggregation of HAPs for major source applicability determination is limited to the surface site and is connected by ancillary equipment.

"Natural gas transmission and storage facility means any grouping of equipment where natural gas is processed, compressed, or stored prior to entering a pipeline to a local distribution company or (if there is no local distribution company) to a final end user. Examples of a facility for this source category are: an underground natural gas storage operation; or a natural gas compressor station that receives natural gas via pipeline, from an underground

natural gas storage operation, or from a natural gas processing plant. The emission points associated with these phases include, but are not limited to, process vents. Processes that may have vents include, but are not limited to, dehydration and compressor station engines. Facility, for the purpose of a major source determination, means natural gas transmission and storage equipment that is located inside the boundaries of an individual surface site (as defined in this section) and is connected by ancillary equipment, such as gas flow lines or power lines. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Natural gas transmission and storage equipment or groupings of equipment located on different gas leases, mineral fee tracts, lease tracts, subsurface unit areas, surface fee tracts, or surface lease tracts shall not be considered part of the same facility."

Based on this definition, the DAQ believes only the HAPs at the expansion site and the existing Mockingbird Hill Compressor Station should be aggregated for major source applicability determination under Subpart YYYY because these sites share the primary role of compressing natural gas through the same pipeline segment. Thus, the potential to emit of total HAPs for the Mockingbird Hill Compressor Station is 6.06 tons per year as a result of this permitting action, which is less than the major source threshold values of ten (10) tons of any single HAP or twenty-five (25) tons of total HAPs per year. Therefore, the facility is not a major source of HAPs in accordance with Subpart YYYY of Part 63 and the turbines are not affected sources under Subpart YYYY.

The "major source" definition in the RICE MACT notes that emissions that are not part of the same natural gas transmission and storage facility shall not be aggregated for major source applicability determinations and referrers to Subpart HHH of Part 63 for the definition of a "*facility"*.

The definition of *"facility"* as defined in Subpart HHH is the following:

"Facility means any grouping of equipment where natural gas is processed, compressed, or stored prior to entering a pipeline to a local distribution company or (if there is no local distribution company) to a final end user. Examples of a facility for this source category are: an underground natural gas storage operation; or a natural gas compressor station that receives natural gas via pipeline, from an underground natural gas storage operation, or from a natural gas processing plant. The emission points associated with these phases include, but are not limited to, process vents. Processes that may have vents include, but are not limited to, dehydration and compressor station engines.

Facility, for the purpose of a major source determination, means natural gas transmission and storage equipment that is located inside the boundaries of an individual surface site (as defined in this section) and is connected by ancillary equipment, such as gas flow lines or power lines. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Natural gas transmission and storage equipment or groupings of equipment located on different gas leases, mineral fee tracts, lease *tracts, subsurface unit areas, surface fee tracts, or surface lease tracts shall not be considered part of the same facility."*

Again, the DAQ interprets this definition for major source applicability under the RICE MACT that only the emissions of the same natural gas transmission and storage facility shall be aggregated. Thus, the total HAPs from the Mockingbird Hill Compressor Station, as a result of this permitting action would be 6.06 tons per year and is less than the major source threshold values. Therefore, the emergency engine would be classified as a new stationary engine located at an area source of HAPs. Since this engine is subject to NSPS Subpart JJJJ, 40 CFR §63.6590(c) and (c)(1) notes that engines located at an area source of HAPs where the engine is complying with the requirements of Subpart JJJJ of Part 60, no further requirements of Subpart ZZZZ apply to the engine.

The proposed emergency generator meets the requirements of Subpart ZZZZ of Part 63 by complying with the requirements of Subpart JJJJ of Part 60, which has been incorporated into the draft permit.

The following is the definition used in the Boiler MACT.

"Major source for oil and natural gas production facilities, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination."

The main function of the Hastings Compressor Station is to increase the compression of a local field gas gathering system assisting in the delivery of wet field gas to the Hastings Extraction Plant (a gas processing plant). Thus, the DAQ understands that HAPs emissions from this gas production support facility shall not be aggregated with the Mockingbird Hill Compressor Station. However, this regulation does not clearly define what a facility is or what an oil or gas production facility is either.

Based on the definitions in Subparts HHH, ZZZZ and YYYY which define what HAP emissions are to be aggregated natural gas transmission and storage facilities for major source applicability, the DAQ believes that EPA has left the definition of facility open for interpretation in this regulation. In the past, DETI and DAQ have aggregated the HAPs for each individual surface site as it is defined in the applicable regulation, which has determined that the sites are area sources of HAPs. The writer's review of the definitions in these regulations did not identify any particular language that would clearly define how aggregation should be performed under Subpart DDDDD without referring to the other regulations. The DAQ concurs with the applicant that the Mockingbird Hill Compressor Station would be classified as a area source of HAPs under the regulation and the proposed boiler would not be an affected source under Subpart DDDDD.

There are no other subparts under Part 63 that are potentially applicable to this facility. Under 45 CSR 30, the Hastings Complex will remain classified as a major source under the Title V Operating Permit Program. As a result of this action, the facility will be required to update the facility's Title V Permit. DETI has elected in this application to submit a concurrent Significant Modification application of the facility's Title V Permit to address this requirement.

TOXICITY OF NON-CRITERIA REGULATED POLLUTANTS

The majority of non-criteria regulated pollutants fall under the definition of HAPs which, with some revision since, were 188 compounds identified under Section 112(b) of the Clean Air Act (CAA) as pollutants or groups of pollutants that EPA knows, or suspects may cause cancer or other serious human health effects. The following HAPs are routinely emitted from combustion units: Benzene, Ethylbenzene, Formaldehyde, Toluene, and Xylene. The following table lists each HAP's carcinogenic risk (as based on analysis provided in the Integrated Risk Information System [IRIS]):

Table # 9 – Toxicity Classification of the Emitted HAPs

HAP	Type	Known/Suspected Carcinogen	Classification
Formaldehyde	VOC	Yes	Category B1 - Probable Human Carcinogen
Benzene	VOC	Yes	Category A - Known Human Carcinogen
Ethylenebenzene	VOC	No	Inadequate Data
Toluene	VOC	No	Inadequate Data
Xylenes	VOC	No	Inadequate Data

All HAPs have other non-carcinogenic chronic and acute effects. These adverse health effects may be associated with a wide range of ambient concentrations and exposure times and are influenced by source-specific characteristics such as emission rates and local meteorological conditions. Health impacts are also dependent on multiple factors that affect variability in humans such as genetics, age, health status (e.g., the presence of pre-existing disease) and lifestyle. *There are no federal or state ambient air quality standards for these specific chemicals*. For a complete discussion of the known health effects of each compound refer to the IRIS database located at *www.epa.gov/iris*.

PSD REVIEW REQUIRMENTS

45 CSR 14 (PSD) requires applicants to determine the Best Available Control Technology (BACT) for each process and pollutant for which the project is major. These applicants have to demonstrate that the increase in emissions of the pollutant will not cause or contribute to an exceedance of the National Ambient Air Quality Standard (NAAQS) and will not exceed the increment threshold of the pollutant for which the project is major. In addition to these requirements, the applicant has to prepare an additional impacts analysis which must include a visibility impact analysis. These requirements ensure that the project in question is implementing the BACT level of control technology for each pollutant for which the project is major and that projected impacts associated with such increases would have minimal effects on the environment.

Best Available Control Technology (BACT) Evaluation

The Hastings Complex is classified as an existing major source. The proposed project will result in a significant emission increase and significant net emissions increase for PM, PM_{10}, $PM_{2.5}$ and GHGs. As such, an analysis to ensure implementation of the Best Available Control Technology (BACT) is required for each pollutant with a significant net emissions increase. DETI conducted a technical review to investigate BACT decisions for PM, PM_{10}, $PM_{2.5}$, GHGs pollutants that have recently been determined by various permitting authorities across the U.S. to satisfy BACT requirements.

METHODOLOGY

In the 1977 Amendments to the federal Clean Air Act (CAA), Congress enacted a program for the PSD regulations defining the requirements that a state must meet if that state chooses to adopt and obtain U.S. EPA approval of a PSD program (42 U.S.C. §§7410(a)(2)(D), 7471). Among the PSD requirements imposed, the state must require any proposed major emitting facility subject to the PSD program to apply BACT for each pollutant subject to regulation under the CAA that the source emits in a significant amount (42 U.S.C. §§7475(a)(4)). Under the CAA, BACT limits are to be determined on a case-by-case basis after taking into account energy, environmental, and economic impacts (42 U.S.C. §§7479(3)). West Virginia has an approved PSD program, pursuant to a U.S. EPA approved State Implementation Plan (SIP).

45 CSR 14 requires that BACT be applied to major modifications for each pollutant with a significant net emissions increase. The definition of "significant" is pollutant specific and is found in West Virginia regulations as summarized under §45-14-2.74.a. The net emissions

increase for PM, PM_{10}, $PM_{2.5}$ and GHG exceeds the SERs as noted in previous sections, thereby triggering the requirement for BACT review.

In a memorandum dated December 1, 1987, U.S. EPA stated its preference for a "top-down" analysis for BACT review. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically, environmentally, or economically infeasible for the unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. Presented below are the five basic steps of a top-down BACT review as identified by the U.S. EPA.

- **Step 1 – Identify All Control Technologies**

  Available control technologies with the practical potential for application to the emission unit and regulated air pollutant in question are identified. Available control options include the application of alternate production processes and control methods, systems, and techniques including fuel cleaning and innovative fuel combustion, when applicable. The application of demonstrated control technologies in other similar source categories to the emission unit in question can also be considered. Technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental and energy impacts, control technologies with potential application to the emission unit under review are identified.

Particulate Matter, which includes PM_{10} and $PM_{2.5}$ BACT for the Combustion Turbines

The emissions of particulate matter from gaseous fuel combustion have been estimated to be less than 1 micron in equivalent aerodynamic diameter, have filterable and condensable fractions, and usually consist of hydrocarbons of larger molecular weight that are not fully combusted. Because this particulate matter typically is less than 2.5 microns in diameter, this BACT discussion assumes the control technologies for PM, PM_{10}, and $PM_{2.5}$ are the same.

Pre-Combustion Control Technologies

The major sources of PM, PM_{10}, and $PM_{2.5}$ emissions from gaseous fuel-fired combustion turbines and compressor engines are:

- The conversion of fuel sulfur to sulfates and ammonium sulfates;
- Unburned hydrocarbons that can lead to formation of PM in the exhaust; and
- PM in the ambient air entering the combustion turbine (combustion air) and aqueous ammonia dilution air.

The use of clean-burning, low-sulfur gaseous fuels will result in minimal formation of PM, PM_{10}, and $PM_{2.5}$ during combustion. Best combustion practices will ensure proper air/fuel mixing ratios to achieve complete combustion, minimizing emissions of unburned hydrocarbons that can lead to the formation of PM emissions. In addition to good combustion practices, the use of high-efficiency filtration on the inlet air will minimize the entrainment of PM into the combustion turbine exhaust streams.

Post-Combustion Control Technologies

There are several post-combustion PM control systems potentially feasible to reduce PM, PM_{10}, and $PM_{2.5}$ emissions including:

- Cyclones/Centrifugal Collectors;
- Fabric Filters
- Electrostatic Precipitators (ESPs); and
- Scrubbers.

Cyclones/Centrifugal Collectors

Cyclones/centrifugal collects are generally used in industrial applications to control large diameter particles (>10 microns). Cyclones impart a centrifugal force on the gas stream, which directs entrained particles outward. Upon contact with an outer wall, the particles slide down the cyclone wall, and are collected at the bottom of the collector. The design of a centrifugal collector provides for a means of allowing the clean gas to exit through the top of the device. However, cyclones are inefficient at removing small particles.

Fabric Filters

Fabric filters/baghouses use a filter material to remove particles from a gas stream. The exhaust gas stream flows through filters/bags onto which particles are collected. Baghouses are typically employed for industrial application to provide particulate emission control at relatively high efficiencies.

ESPs

ESPs are used on a wide variety of industrial sources, including certain boilers. ESPs use electrical forces to move particles out of a flowing gas stream onto collector plates. The particles are given an electric charge by forcing them to pass through a region of gaseous ion flow called a "corona." An electrical field generated by electrodes at the center of the gas stream forces the charged particles to the collecting plates.

Removal of the particles from the collecting plates is required to maintain sufficient surface area to clean the flowing gas stream. Removal must be performed in a manner to minimize re-entrainment of the collected particles. The particles are typically removed from the plates by “rapping” or knocking them loose and collecting the fallen particles in a hopper below the plates.

Scrubbers

Scrubber technology may also be employed to control PM in certain industrial applications. With wet scrubbers, flue gas passes through a water (or other solvent) stream, whereby particles in the gas stream are removed through inertial impaction and/or condensation of liquid droplets on the particles in the gas stream.

- **Step 2 – Eliminate Technically Infeasible Options**

Pre-Combustion Control Technologies

The pre-combustion control technologies identified above are available and technically feasible for reducing/minimizing the formation PM emissions from the combustion turbine and reciprocating engines.

Post-Combustion Control Technologies

Each of the post-combustion control technologies described above are generally available. However, none of these technologies is considered practical or technically feasible for installation on gaseous fuel-fired combustion turbines or reciprocating compressor engines since $PM_{2.5}$, which, as stated above, makes up the majority of PM emissions from these gaseous fuel-fired sources.

The particles emitted from gaseous fuel-firing are typically less than one (1) micron in diameter. Cyclones are effective on particles with diameter of ten (10) microns or less. Therefore, a cyclone/centrifugal collector is not a technically feasible control technology.

Fabric filters, ESPs, and scrubbers have generally not been applied to commercial combustion turbines or reciprocating engines burning gaseous fuels. Typically, these control technologies have been applied to emissions sources which generate a high concentration of particles with sizes varying between 10 to 1 microns. These sources are typically units that are solid or liquid fuel-fired applications. None of these control technologies is appropriate for use on gaseous fuel-fired combustion turbines and reciprocating engines. Because of their very low PM emission levels, and the small aerodynamic diameter of the PM from gaseous combustion. Review of the RACT/BACT/LAER Clearinghouse (RBLC), as well as USEPA, and State permit databases, indicates that post-combustion controls have not been required as BACT for gaseous fuel-fired combustion turbines or reciprocating engines. Therefore, the use of fabric filters, ESPs and scrubbers are not considered technically feasible.

- **Step 3 – Rank Remaining Control Technologies by Control Effectiveness**

The use of clean-burning fuels, good combustion practices, and inlet air filtration are the technically feasible technologies to control PM, PM_{10}, and $PM_{2.5}$ emissions to no more than 0.02 lb/MMBtu and 0.05 lb/MMBtu from reciprocating engines.

- **Step 4 – Evaluate Most Effective Controls and Document Results**

The use of good combustion practices and inlet air filtration to control PM, $PM_{10,}$ and $PM_{2.5}$ emissions to no more than 0.02 lb/MMBtu for each of the turbines is the most effective control measure. The applicant notes that this value is consistent with BACT at other similar sources.

- **Step 5 – Select BACT**

DETI proposes BACT for PM, PM_{10}, and $PM_{2.5}$ emissions from the combustion turbines is the use of clean-burning fuels, good combustion practices, and inlet air filtration to control PM, PM_{10}, and $PM_{2.5.}$ PM, PM_{10}, and $PM_{2.5}$ emissions from the combustion turbines (CT-01 & CT02) shall be limited to 0.02 lb/MMBtu, which includes both the filterable and condensable portions of PM.

DAQ's Conclusions of the Selection of BACT for the Combustion Turbines

Before discussing the applicant's selected BACT for the turbines, the writer would like to point out key points that need to be taken into consideration, which are condensable particulate and measuring low concentrations. In the past, the condensable portion of the particulate matter was about 30% of the total PM. Combustion improvements keep advancing, which reduces the amount of filterable PM generated. This reduction of filterable PM actually increase the percentage of the condensable portion from the CTs.

Another important point is the testing. Gaseous fuel-fired turbines generally generate low concentrations of particulate matter. This pushes the limitations of the testing methods, apparatus, and personnel in obtaining reliable results. Solar Turbines noted in their Product Information Letter 171 Revision 6 (8 March 2017) that its customers particulate matter source test data show that there is significant variability from test to test. The source test results support the common industry argument that particulate matter from natural gas fired combustion sources is difficult to measure accurately. The reference test methods for particulate matter were developed primarily for measuring emissions from coal-fired power plant and other major emitters of particulates. Particulate concentrations from gas turbines can be 100 to 10,000 times lower than the "traditional" particulate sources. The reference test methods were not developed or verified for low emission levels. There are interferences, insignificant at higher exhaust particulate matter concentrations that result in measurements greater than actual emissions from gas turbines.

Due to measurement and procedural errors, the measured results may not be representative of actual particulate matter emitted. There are many potential error sources in measuring particulate matter. Most of these have to do with contamination of the samples, material from the sampling apparatus getting into the samples, and human error in samples and analysis. Solar Turbines has published several testing recommendations to aid or minimize the above-mentioned measurement issues.

The writer discovered a Solar Titan combustion turbine owned and operated by Dominion Cove Point LNG, LP has a permitted PM_{10} limit of 0.0066 lb/MMBtu that was issued by Maryland Public Service Commission as PM BACT for the unit. This PM BACT level is lower than the proposed level and therefore, this determination was focused on determining if the proposed BACT is justifiable or not.

Cove Point is a natural gas liquefaction and storage facility with a marine terminal. Due to the primary business function of exporting natural gas, the Federal Energy Regulatory Commission requires Dominion Cove Point to internally generate 100% of the facility required electric power. In the permit for Cover Point, the permit specifically notes that PM BACT for the Titan combustion turbine is based on exclusive use of pipeline quality, low sulfur natural gas. The facility operates several combustion turbines to generate electric power required by the facility which includes the identified Titan turbine.

The writer asked DETI to justify the proposed BACT as compared to the BACT limit permitted for the same model turbine at Cove Point. DETI explained that the quality of natural gas used by Cove Point is significantly higher than pipeline quality than the proposed site would transmit and consume. At Cove Point, the liquefication process cannot use pipeline quality natural gas. Therefore, Cove Point must pre-treat the incoming natural gas prior to sending it to the liquefication process. This consist of three main steps which are preheating and mercury removal; acid gas removal; and dehydration. For this discussion, acid gas removal is the considered. Cove Point used an amine treatment with a design specification to remove carbon dioxide to 50 ppm by volume. This amine treatment will reduce the hydrogen sulfide in the gas as well.

The writer contacted Mr. Duane King, Compliance Inspector for the Maryland Department of the Environment, who indicated that Dominion Cove Point LP was having PM measurement issues for the combustion turbines which included the Titan combustion turbine. Mr. King provided a copy of the February 18-19, 2016, Test Report that indicates that Titan Turbine demonstrated compliance with the 0.0066 lb/MMBtu PM limit. The report indicates that the measured rate of total PM was 0.00170 lb/MMBtu. Reviewing the test results for the organic and inorganic condensables, the measured condensable portions accounted for 70% of the total PM. It should be noted that Method 5 and 202 were used with three, four-hour test runs.

Solar recommends to its customers for determining the PM, PM_{10}, and $PM_{2.5}$ emissions for its combustion turbines, to use an emission factor of 0.01 lb/MMBtu fuel input on the assumption that the fuel is pipeline quality natural gas with less than one (1) grain per 100 standard cubic feet. DETI's current FERC Gas Tariff requires DETI to accept gas at receipt points of their pipeline system with a hydrogen sulfide concentration of up to 0.25 grains per one hundred cubic and not more than twenty grains of total sulfur per 100 cubic feet, which is greater than the sulfur loading of Solar's recommendation.

The recommended pre-combustion control technologies by the applicant only effectively control the filterable portion of the particulate. Because of these advancements, the condensable fraction makes up the majority of the total PM. Therefore, the identified post-combustion controls would only control the filterable portion and at a significantly reduced efficiency than what would normally be expected of the same control technologies (i.e. > 99% for Fabric Filters). DAQ agrees with the applicant to eliminate these control technologies from the BACT process and concurs with the applicant on the selection of clean-burning fuel (natural gas), good combustion practices, and pre-combustion air filtration.

The applicant's search of the RACT BACT LAER Clearinghouse (RBLC) of simple cycle turbines with an output of less than 25 megawatts does not reveal a BACT limit at or of less than the proposed limit of 0.02 lb/MMBtu. Therefore, the BACT for PM, PM_{10}, and $PM_{2.5}$ is 0.02 lb/MMBtu for the two Titan 130 combustion turbines.

PM/PM_{10}/$PM_{2.5}$ BACT for the EMERGENCY GENERATOR

For the emergency generator, the applicant proposed to limit the fuel to natural gas and cap the hours of operations to 100 hours per year. Further, DETI does not believe it is appropriate to subject the emergency generator to a BACT review. The proposed engine is natural gas fired and the manufacturer's emission data indicate it will comply with the applicable emission standards of NSPS Subpart JJJJ.

The applicant conducted a review of the RBLC as well as recent permits, that show that add-on controls have not been employed for other similar sized engines which exclusively fire pipeline quality natural gas to control particulate matter. The combustion of natural gas, with a lower ash, and sulfur content than other commonly used fuels (i.e. fuel oil, and coal), generates lower levels of particulate matter emissions compared to other fuels. Through this review, DETI determined that add-on controls are not considered commercially demonstrated for engines of similar size firing natural gas only. DETI proposes the use of pipeline quality natural gas and good combustion practices as BACT for PM, PM_{10}, and $PM_{2.5}$.

DAQ's Conclusions of the Selection of BACT for the Emergency Generator

The DAQ does not agree with the applicant completely. The DAQ believes that the same control technologies that were evaluated for the turbines would be appropriate for a reciprocating engine using the same type of fuel (i.e. natural gas). In addition, DAQ believes that evaluating these same technologies in a top-down BACT approach would result in the same outcome that pre-combustion control technologies would be BACT for PM, PM_{10}, and $PM_{2.5}$.

The DAQ accepts that outcome of the applicant's evaluation of control technologies of BACT for the combustion turbine as the same for this emergency generator. Also, the DAQ believes that restrictions on the engine should be based on limitations for an emergency stationary engine under Subpart JJJJ, instead of just being limited to 100 hours per year. The subpart prohibits emergency engines from operating in situations of peak-shaving or in a manner to generate income for the facility. However, it would allow DETI operate the engine for 100 hours per year for non-emergency situations and unlimited for emergency situations. This writer believes that a 100-hour per year operating limit may be too restrictive due to the location of this facility and lack of other near-by local utility consumers. This writer believes the restriction should be established based on the limitation of an emergency stationary engine under Subpart JJJJ.

Given this emission unit is proposed to be a limited use (100 hours per years + during emergencies where there is interruption of local electricity service), setting the BACT based on the applicable standard for an emergency stationary engine as defined under Subpart JJJJ to Part 60 and is reasonable to the DAQ. DAQ concurs with the use of good combustion practices as BACT, however it needs to be defined in some reasonable manner that is either measurable or recordable. The DAQ believes that engine tune-up would be a reasonable work practice and can be recordable. Thus, DAQ establishes BACT for this engine to be operated as an emergency stationary engine as defined under Subpart JJJJ with a limit of 0.07 pounds of PM, PM10, and PM2.5 with engine tune-up performed at least once every five years and be limited to using pipeline quality natural gas.

PM/PM_{10}/$PM_{2.5}$ BACT for the BOILER

Pipeline quality natural gas will exclusively fuel the boiler. The boiler emissions assume the unit will operate for 8,760 hours per year, but the boiler will only operate when needed for comfort heat.

A review of the RBLC as well as recent permits shows that add-on controls have not been employed for other similarly sized auxiliary boilers which exclusively fire pipeline quality natural gas to control particulate matter. The combustion of natural gas, with a lower ash and sulfur content than other commonly used fuels (i.e. fuel oil, and coal), generates lower levels of particulate matter emissions compared to other fuels. Through this review DETI determined that add-on controls are not considered commercially demonstrated for boilers of a similar size firing natural gas only. DETI proposed the use of pipeline quality natural gas and good combustion practices as BACT for PM, PM_{10}, and $PM_{2.5}$.

DAQ's Conclusions of the Selection of BACT for the Boiler

Again, the DAQ does not agree with the applicant's presentation of the BACT Analysis for the proposed boiler for PM, PM_{10}, and $PM_{2.5}$. As noted in the above for the emergency generator, the same control technologies that were identified for the combustion turbine would potentially be applied to a natural gas fired boiler. The applicant points out but does not capitalize on the added controls mainly control filterable particulate matter which is not the majority component of the total PM generated, and the size of the boiler.

The filterable portion of the particulate matter is only 0.02 pounds per hour, which equates to less than 0.25% of the total of this project. This would be the portion of the particulate matter from the boiler that could be controlled with the identified add-on control devices from the BACT for the turbines.

Most of the PM that is generated is the condensable fraction, which is significantly limited based on the exclusive use of natural gas as the fuel for this unit.

The use of other pre-combustion controls for this unit is limited due to the size and design of the unit. This unit is a three pass, wet back style boiler to generate hot water (i.e. building heating system). Because the unit would be limited to heating season, an oxygen trim system would not be economical to install and maintain. The best available work practice is conducting boiler tune-ups.

The writer verified the applicant's review by searching the RBLC for the past ten years of Process Types 13.310 – less than 100 MMBtu/hr Natural Gas (includes propane and liquefied petroleum gas) units. Of the entries that listed the entity used pollution prevention as the selected control option. Some of these entries had a BACT limit lower than what DETI proposed. However, these limits were not verified.

DAQ establishes PM, PM_{10}, and $PM_{2.5}$ as BACT for this boiler to be limited 0.28 tons per year with limitation on fuel type to pipeline quality natural gas and boiler tune-up conducted once every five years.

BACT for Greenhouse Gases (GHG)

The proposed changes at Mockingbird Hill Compressor Station will result in increased GHG emissions by more than 75,000 tpy (CO2e). Per EPA's PSD and Title V Greenhouse Gas Tailoring Rule definitions, GHGs consist of the following gases:

- Carbon Dioxide (CO2)
- Methane (CH4)
- Nitrous Oxide (N2O)
- Hydrofluorocarbons (HFCs)
- Perfluorocarbons (PFCs)
- Sulfur Hexafluoride (SF6)

To determine CO_2e emissions, mass flows of each individual gas are multiplied by the appropriate Global Warming Potential (GWP) as referenced in the Mandatory Greenhouse Gas Reporting Rule (40 CFR 98, Subpart A, Table A-1). The results are then summed to determine CO_2e emissions.

The combustion turbines, as well as the other, smaller combustion sources, will be fired with pipeline-quality natural gas, and efficient combustion of methane will result primarily in water and CO_2 by-products. Additionally, due to the presence of nitrogen in the combustion air, some N_2O will also be emitted. However, fugitive emissions—such as periodic venting of the pipeline for maintenance, methane leaks and trace emissions due to incomplete combustion will result in natural gas or CH_4 emissions.

Because BACT applies to "each pollutant subject to regulation under the Act," the BACT evaluation process is typically conducted for each regulated pollutant individually and not for a combination of pollutants. This is not the case for GHG PSD applicability where the regulated NSR pollutant subject to regulation under the Clean Air Act (CAA) is the sum of six greenhouse gases. In the final Tailoring Rule preamble, EPA made clear that the combined pollutant approach for GHGs does not apply just to PSD applicability determinations but also to PSD BACT determinations. In this case, applicants must conduct a single GHG BACT evaluation based on CO_2e for emission sources that emit more than one GHG pollutant:

"However, we disagree with the commenter's ultimate conclusion that BACT will be required for each constituent gas rather than for the regulated pollutant, which is defined as the combination of the six well mixed GHGs. To the contrary, we believe that, in combination with the sum-of-six gases approach described above, the use of the CO_2e metric will enable the implementation of flexible approaches to design and implement mitigation and control strategies that look across all six of the constituent gases comprising the air pollutant (e.g., flexibility to account for the benefits of certain CH_4 control options, even though those options may increase CO_2). Moreover, we believe that the CO_2e metric is the best way to achieve this goal because it allows for tradeoffs among the constituent gases to be evaluated using a common currency.vi"

As defined in Subpart 1, Section 169.3 of the Clean Air Act, BACT is an "emission limitation," which means it is a performance requirement, not an emission rate reduction achieved through control equipment and based on an equipment standard. While BACT is predicated upon the application of technologies reflecting the best practical level of control (or emission reduction), the final result of a BACT determination is an emission limitation. Typically, when quantifiable and measurable, this limit would be expressed as an emission rate limit of a pollutant. In the case of GHG, EPA Guidance has indicated that GHG BACT limitations should be averaged over long-term timeframes such as a 30- or 365-day rolling averages.

GHG BACT for Simple-Cycle Combustion Turbines

The sources to be permitted consist of two 20,500 hp (ISO) simple-cycle combustion turbine mechanical compressor driven engines, fired with pipeline quality natural gas. Mockingbird Hill Compressor Station is designed to maximize the regional natural gas supply's reliability using proven, commercially available equipment. The Mockingbird Hill Compressor Station has no secondary use for thermal energy (steam or hot water) or bulk electricity generated on site. In keeping with GHG reduction principles, Mockingbird Hill Compressor Station operates as efficiently as practicable.

Natural gas compressors are engine driven mechanical drive units that utilize the combustion of fuel (in this case, pipeline quality natural gas) to generate mechanical energy. For the proposed project, combustion turbine engines are to be installed, each driving a centrifugal compressor connected via rotating shaft. In limited cases, some gas compressors are driven using an electric motor to turn the same type of centrifugal compressor – an arrangement that is less fuel efficient and more carbon intensive than directly coupling the compressor to its energy production source. This type of compression does not require the use of natural gas to operate, but rather relies upon the fuel mix of the connected electrical grid to produce energy, which results in line losses and multiple energy conversion losses before arriving at the station. Such installations introduce another measure of gas supply unreliability, since an electrical outage would also force a simultaneous natural gas supply outage.

Electric driven compressors are an option for Mockingbird Hill Compressor Station. However, when considering their entire carbon life cycle, electric driven compressors would represent a higher carbon emitting alternative than the proposed natural gas-fired combustion turbine engine drives. Since electric drives in this instance are less fuel efficient, produce greater GHG emissions, and introduce natural gas reliability limitations, they were not considered in this GHG BACT analysis.

Top-Down BACT Process

According to the Guidance, BACT analysis for GHG emissions should be conducted in a manner consistent with the historical practice of BACT analyses, using the 5-step "top-down" approach originally laid out in EPA's Draft 1990 Workshop Manual. Given that most GHG emissions are a result of fossil fuel combustion, EPA suggests that a GHG BACT analysis should consider energy efficiency measures that reduce the need for fuel combustion, either by (a) combusting fuel more efficiently; (b) using the energy produced more efficiently; or (c) a combination of (a) and (b). These measures are especially relevant due to the relative lack of current "end-of-pipe" controls for GHG emissions.

The process steps that were laid out in the PM/PM_{10}/$PM_{2.5}$ BACT will be used for the GHG BACT, which are described in the following sections.

Step 1 – Identify All Available Control Technologies

The Guidance has placed potentially applicable control alternatives identified and evaluated in the BACT analysis into the following three categories:

• Inherently Lower Emitting Processes/Practices/Designs;

• Add on Controls; and

• Combinations of Inherently Lower Emitting Processes/Practices/Designs and Add On Controls.

EPA recommends that the BACT analysis should consider potentially applicable control techniques from all three categories. The Guidance also specifies that while GHG BACT analyses can include control measures that can be used facility-wide, Step 1 of the process should not consider secondary emissions (for example: measures that reduce electrical demand from the grid at the facility, thereby resulting in reduced demand for fuel combustion at off-site electric generating units). However, these off-site effects could be considered in Step 4 as appropriate. The following potential CO_2 control strategies for simple-cycle natural gas fired mechanical drive combustion turbines will be analyzed as part of this BACT analysis:

• Carbon capture from the turbine stacks and permanent sequestration;

• Selection of natural gas compression process efficiency improvements;

• Selection of low carbon fuel; and

• Good combustion/operating practices (to optimize operating efficiency).

Carbon Capture and Sequestration

Carbon capture and sequestration (CCS) falls under the category of add-on controls, which are air pollution control technologies that remove pollutants from a facility's emissions stream. EPA suggests that CCS is an add-on pollution control technology that is "available" for large CO_2 emitting facilities and industrial facilities with high purity CO_2 streams. As a result, EPA suggests that CCS be considered in Step 1 of the BACT analysis.

CCS is composed of three main components: CO_2 capture and/or compression, transport, and sequestration. It is useless to capture CO_2 unless it can be prevented from re-entering the atmosphere permanently. Simply capturing and storing CO_2 for re-use or where it can be gradually re-released does not represent a real reduction in global GHG emissions. To deploy CCS successfully, the design must have a component of both capture and sequestration. In fact, CO_2 separation without permanent sequestration actually results in an increase in total CO_2 generation, since the separation system itself requires energy.

For the Solar simple-cycle combustion turbines, CCS would be technically infeasible and would fundamentally re-define the source being permitted. If CO_2 capture were installed at the compressor station, the Solar turbines would be incapable of delivering the required shaft horsepower to the compressors due to increased backpressure. Further, Mockingbird Hill Compressor Station would require a high voltage transmission line and additional electrical load to operate the equipment – itself requiring upstream increases in CO_2 emissions (including those from higher carbon emitting coal or oil-fired power plants). Such a system, assuming amine scrubbing, would require the addition of a form of chemical plant. The facility would take on a substantial footprint, high visibility and would require additional staff to operate.

The CO_2e PTE from the proposed Solar turbines is projected to be 182,118 TPY. A summary of the individual GHG pollutants along with its global warming potential is provided in Table 10 below:

Table 10: MOCKINGBIRD HILL COMPRESSOR STATION PROJECT COMBUSTION TURBINES GHGs AND CO_2E PTE

GHG Pollutant	Potential to Emit (PTE) (tpy)	GWP*	Combustion Turbines CO_2e PTE (TPY)
CO_2	180,393	1	180,393
CH_4	14.8	25	370
N_2O	4.55	298	1,355
		Total	182,118

* GWP – Global Warming Potential from Table A-1 to Subpart A of Part 98

In the IPCC Special Report on CCS, the cost to perform post combustion carbon capture on a combustion turbine was estimated to be $25-115 per ton CO2 captured (net). The cost to transport CO2 via pipeline from the site of capture to the site of sequestration is estimated at $1-8 per ton of CO2 transported and the cost for injection at $0.5-8 per ton. These estimates do not include the costs associated with construction, operation, maintenance, and other liabilities to the Project to implement CCS.

Even if CCS were to be technically feasible at the Mockingbird Hill Compressor Station project, determining an appropriate threshold cost for CO_2e is a challenge. In terms of PSD applicability, under the "Tailoring Rule," the USEPA considers 100,000 tons of CO_2e equal to 100 tons of a criteria pollutant. In comparing the threshold value of cost effectiveness for CO_2e, calculations must be based on the relative cost effectiveness of control of a criteria pollutant at some threshold value per ton of pollutant removed and the major source threshold of 100 TPY. USEPA's rulemaking construct supports this approach; if a criteria pollutant control has a cost effectiveness threshold of approximately $8,000 per ton, then the equivalent cost effectiveness for CO_2e control should be $8/ton ($8,000 x 0.001). Given this cost analysis, implementation of CCS again proves infeasible.

Selection of the Most Efficient Compressor Drive/Multiple, smaller reciprocating engines coupled to multiple small gas compressors would be required to produce the same output as the combustion turbines that have been selected for the project. As a result, using reciprocating engines would not constitute a more efficient or lower carbon-emitting alternative and would redefine the source being permitted. Since no comparable single engine is commercially available in this size or for this application, reciprocating engines are not considered further in this analysis.

Selection of Low Carbon Fuel

The proposed Mockingbird Hill Compressor Station combustion turbines will be fired with pipeline-quality natural gas. The combustion of natural gas has the lowest emissions of GHGs of any fossil fuel and emits almost 30 percent less CO_2 than oil, and about 45 percent less CO_2 than coal. The exclusive use of pipeline quality natural gas to fuel the proposed gas compressor drive engines reflects a component of BACT for GHG from this application.

Good Combustion/Operating Practices

Good combustion and operating practices are considered to be a potential control option by improving the fuel efficiency of the combustion turbines. Good combustion practices also include proper maintenance and computer automation within the manufacturer's specifications of combustion turbine operations. Combustion turbines are monitored and controlled automatically via computerized control systems set up and monitored by the Original Equipment Manufacturer (OEM). These systems constantly adjust turbine operation in real time to maintain safe, pre-programmed and highest efficiency operation. Should any monitored parameter stray from its design range, the operator (or a remote operator) will be notified by alarm. If the system deems the fault to be critical to safe operation, protection of the equipment or meeting regulatory requirements, the control system will initiate a safe shutdown of the unit.

DETI has in place a maintenance program for all of its natural gas compressor stations. The Mockingbird Hill Compressor Station emission sources are operated under that program. Good combustion and operation is therefore integral to the proposed compressor engine and represents a component of GHG BACT for this application.

Step 2 – Eliminate Technically Infeasible Options

As discussed above, CCS or substitution of other types of processes or engines are determined to be technically infeasible for control of GHG emissions from the sources being permitted. However, EPA guidance stipulates that CCS costs should be evaluated and therefore it will be carried through to Step 4.

The Guidance also notes that for BACT analysis for GHG control strategies, "it may be appropriate in some cases to assess the cost effectiveness of a control option in a less detailed, quantitative (or even qualitative) manner" as compared to BACT analyses for other regulated NSR pollutants.

Step 3 – Rank Remaining Control Technologies

Based on the discussion in Steps 1 and 2, the only technically feasible control options for GHGs are:

• Carbon capture and Sequestration;

• Selection of the most efficient compressor drive that meets the project definition;

• Selection of low carbon fuel; and

• Good combustion/operating practices.

Ranking the above control technologies is not necessary as DETI plans to implement all except for CCS at Mockingbird Hill Compressor Station.

Step 4 – Evaluate Most Effective Controls and Document Results

Under Step 4 of the top down BACT analysis, economic, energy, and environmental impacts must be evaluated for each option remaining under consideration.

DETI evaluated the cost effectiveness of CCS for the proposed project and found that CCS is not cost effective at $267/ton removed. A copy of the applicant's detailed calculations for cost-effectiveness of CCS may be found in Appendix B of this determination.

The Solar combustion turbines have been demonstrated to be one of the most efficient simple-cycle turbines for this application. The turbines will be fired with natural gas, which is the most carbon efficient fuel and will be operated and maintained using good combustion practices.

Step 5 – Select the BACT

In Step 5 of the BACT determination process, the most effective control option not eliminated in Step 4 should be selected as BACT for the pollutant and emissions unit under review and included in the permit.

The CCS option was eliminated in Step 2 as not technically feasible for the Project. Even though DETI's analysis eliminated CCS in Step 2, due to EPA guidance, DTI continued the evaluation through Step 4 of the BACT process where it was found to not be cost effective. Although EPA considers CCS as available, it is not commercially available. In fact, EPA recognizes that at present, CCS is an expensive technology, largely because of the costs associated with CO_2 capture and compression.

The Solar combustion turbines fueled with natural gas along with good combustion/operating practices is proposed as BACT for Mockingbird Hill Compressor Station.

EPA encourages the use of output-based BACT limits, where feasible and appropriate, and suggests that GHG BACT limits should focus on long-term averages based on the cumulative, rather than acute, environmental impact of GHG emissions. In a mechanical drive compressor application there is no discreet, measurable product output. In this application, CO_2 emission limits must be based on mass emissions (lb) per heat input (MMBtu), or, more simply, annual average hourly tons of CO_2. Therefore, DTI proposes an efficiency based BACT emission limit for the proposed Mockingbird Hill Compressor Station turbines as follows:

Solar Titan 130. Output based BACT limit of 1.01 lbs. CO_2e per horsepower hour on a 12-month rolling average. The BACT limit is based on the following calculation:

$$\frac{20{,}757\ lb\ CO_2e}{hour} \times \frac{hour}{20{,}500\ hp-hr} = \frac{1.01\ lb\ CO_2e}{hp-hr}$$

Additionally, DETI proposes a combined annual mass CO_2e permit limit for the new Mockingbird Hill Compressor Station turbines, which equates to 41,514 lb of CO_2e per hour.

DAQ's Conclusions of the Selected GHG BACT for the Simple Cycle Combustion Turbines

This writer reviewed the DAQ's GHG BACT Analysis for ESC Harrison County Power (Permit Application R14-0036). The DAQ concurred with the applicant's analysis for this determination that there were no feasible add-on controls for the combined-cycle combustion turbines and fuel gas heater for GHGs. Therefore, DETI conclusion is consistent with the DAQ's recent determination of GHG BACT for combustion turbines.

Since this facility is a natural gas compressor station which has other point sources and fugitive sources of GHGs, it is not appropriate set a mass limit of GHG for the facility. Therefore, the BACT limit for GHGs for each turbine is limited to using natural gas with a CO_2e limit of 1.01 lb per hp-hr and 90,916 tpy with both limits on a 12-month rolling total.

GHG BACT for Engine of the Emergency Generator and Boiler

The proposed emergency generator engine and the boiler will be fueled with natural gas. GHG emissions for natural gas combustion are 116.9 lb CO_2e/MMBtu compared to 163.6 lb CO_2/MMBtu for distillate fuel oil consumption. Therefore, firing natural gas generates less GHGs than firing oil.

These sources represent less than 5% of the combustion GHG emissions from the project. The boiler is necessary for heating purposes during winter months. The actual GHG emissions from the boiler are expected to be considerably lower due to the inherent nature of its function. The generator's PTE is based on 500 operating hours per year and its actual GHG emissions will be less because the engine will be limited to 100 hours of non-emergency operating hours and unlimited operation during an emergency as defined in Subpart JJJJ.

Step 1 – Identify All Available Control Technologies

The first step in the top-down BACT process is to identify all "available" control options. Available control options are those air pollution control technologies or techniques (including lower emitting processes and practices) that have the potential for practical application to the emissions unit and regulated pollutant under evaluation. Use of low carbon fuel and energy efficient design have been identified as control technologies available to the boiler.

The proposed engine and boiler will be fired with pipeline-quality natural gas. The combustion of natural gas has the lowest emissions of GHGs of any fossil fuel and emits almost 30 percent less CO_2 than oil, and about 45 percent less CO_2 than coal.

In the GHG BACT guidance, EPA has stressed importance of energy efficiency for combustion sources. The proposed units maximize efficiency while meeting the required emissions standards.

Step 2 – Identification of Technically Feasible Control Alternatives

Under the second step of the top-down BACT analysis, a potentially applicable control technique listed in Step 1 may be eliminated from further consideration if it is not technically feasible for the specific source under review. EPA considers a technology to be potentially applicable if it has been demonstrated in practice or is available. The energy efficient use of the lowest carbon fuel (natural gas) used is considered to be the only technically feasible CO_2 control option for the engines and boiler.

Step 3 – Rank Remaining Control Technologies

After the list of all available controls is narrowed down to a list of the technically feasible control technologies in Step 2, Step 3 of the top down BACT process calls for the remaining control technologies to be listed in order of overall control effectiveness for the regulated New Source Review (NSR) pollutant under review. Based on the discussion in Steps 1 and 2, the only technically feasible control option for CO_2 from the engines and boiler is energy efficiency through the use of low carbon fuel (natural gas).

Step 4 – Evaluate the Most Effective Controls and Document Results

In the top-down BACT analysis, the "top" control option should be established as BACT unless the applicant demonstrates, and the permitting authority agrees, that the energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered.

Step 5 – Select the BACT

In Step 5 of the BACT determination process, the most effective control option not eliminated in Step 4 should be selected as BACT for the pollutant and emissions unit under review and included in the permit.

Energy efficiency through the regulation of fuel used is the only remaining and feasible control technology. The selected as GHG BACT for the engine and boiler is the use of natural gas. Additionally, the use of natural gas in the engines and boiler results in the lowest GHG emission practicable.

The boiler will be operated as needed to heat the station during the winter months ensuring no malfunctions due to freezing occur. Thus, fuel use is optimized, resulting in lower GHG emissions than if the unit operated continuously.

The engine and boiler account for less than 1% percent of the total GHG emissions potential of the project with expected actual emissions to be even less.

The use of natural gas as fuel represents the best available option in controlling GHG emissions from the engines and boiler. This is consistent with the 40 CFR 52.21 definition of BACT, which provides for cases where the imposition of an emissions standard would be infeasible for an emission unit, that "*a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology."*

Due to the small amount of GHG emissions potential from the natural gas fired engines and boiler, a numerical GHG emission limit is not proposed.

DAQ's Conclusions of the Selected GHG BACT for the Emergency Generator and Boiler

The potential GHG emissions from these two sources are 4,633 tons of CO_2e per year using natural gas. DAQ concurs with the applicant's conclusion of GHG BACT for the engine and boiler.

The applicant proposed not to establish a numerical GHG limit for these sources and requested a BACT limit as a fuel limit by limiting the fuel to pipeline quality natural gas. The DAQ agrees with this approach, with one exception; that a work practice measures should be included as the BACT limit to ensure energy efficiency of the units are maintained through tune-ups once every five years. Therefore, GHG BACT for the boiler and engine is limited to using pipeline quality natural gas with tune-ups once every five years in accordance with the manufacturer's specifications.

Other Sources of GHGs that Relate to the Compressors and Compressor Station

There are several other point sources of GHG which are released on an intermittent basis. These sources are compressor blowdowns, facility-wide blowdowns, and blowdown of the pig receivers and launchers. The planned facility-wide and pig receiver/launcher blowdowns rarely occur more than once per year. These events are usually either performed to satisfy a safety check requirement or to perform a pipeline integrity demonstration. Due to the low frequency of these releases and DETI agreement to limit the planned facility-wide blowdown to once per year, no GHG BACT analysis was conducted for the facility-wide and pigging blowdowns.

The natural gas is vented from the compressor during the startup/shutdown cycle of the compressor. DETI estimated that there is potential to emit 2,847 pounds of methane per complete cycle, which equates to 71,175 lb of CO_2e per cycle. These emissions are product (natural gas) that was trapped in the compressor during shutdown and purging the air in the compressor at startup.

Vapor recovery units (VRUs) are widely used in the gas production sector to capture product (residue gas) from several different release points (i.e. tanks, separators, columns). The writer requested DETI conduct a feasibility analysis of using a similar VRU system to control GHG emissions due to compressor blowdown. DETI determined that the technology was technically feasible for shutdowns. However, DETI determined that the cost effectiveness of this type of control would be $34 per ton CO_2e removed, which equates to $5,980 per ton of methane recovered. As a result of this cost analysis, DETI determined the use of a vent gas recovery system similar to a VRU is not economically feasible. DETI agreed to limit the number of startup/shutdown cycles as a BACT limit for GHG due to compressor blowdowns.

GHG BACT for Fugitive Components

As discussed earlier, some fugitive components such as flanges, valves, and openended lines (OELs) within the facility boundary would be associated with the proposed combustion turbines. Natural gas released from fugitive components represents a potential source of GHG emissions from the facility in the form of methane contained in the natural gas.

DETI expects to comply with NSPS Subpart OOOOa requirements upon startup of the compressor with the applicable fugitive leak provisions of Subpart OOOOa as BACT.

As promulgated in Part 60, Subpart OOOOa specifically notes that this leak detection and repair program is to minimize fugitive source of VOCs and GHGs from natural gas compressor stations. Based on the definition of BACT under 45 CSR 14, the implementation of the LDAR program from Subpart OOOOa would be the minimum acceptable level for GHG BACT of fugitive sources. There are other promulgated LDAR programs available but no other specifically notes that the program is focused on GHGs. Therefore, the DAQ concurs with the applicant's selection of GHG BACT of fugitive sources by implementing the requirements of 40 CFR 60.5397a.

AIR QUALITY IMPACT ANALYSIS

The applicant provided a Class II Air Quality Modeling report to demonstrate this proposed project will not exceed the Class II Area increment thresholds as listed in 45 CSR §14-4.1. and the National Ambient Air Quality Standards (NAAQS). In addition to this report, DETI conducted a Class I Significant Impact Analysis to satisfy the requirements of the rule and ensure that the emissions from the project would not cause any adverse impacts in any of the near-by Class I areas, which include: Dolly Sods, James River Face, Otter Creek Wilderness Areas and the Shenandoah National Park.

The Mockingbird Hill Compressor Station is in Wetzel County, which is designated by U.S. EPA as "unclassifiable" and/or "attainment" for the NAAQS for ozone, PM_{10}, and $PM_{2.5}$. To demonstrate compliance with the NAAQS, DETI conducted an air quality analysis for these pollutants. Note that since there is no NAAQS standard for PM, modeling of this pollutant was not required to be performed.

Class I Area SIL Analysis

In order to ensure that the emissions from the project will not contribute to exceedances of the Class I Increment standards at any of the Class I areas located within 200 km of the facility, DETI performed a screening analysis for Class I Increments. DETI initially built an arc of receptors located approximately 50 km from the Project location (i.e., 50 km is the maximum recommended range for use of AERMOD). As the distance of 50 km is closer to the project location than all Class I areas, the model output concentrations should over-predicted compared to those expected at the actual distances.

The following table is a summary of the results of this screening analysis.

Table #11 Class I Area Screening Analysis

Pollutant	Averaging Period	Max Concentration ($\mu g/m^3$)	SIL ($\mu g/m^3$)
$PM_{2.5}$	24-Hour	0.018	0.07
	Annual	0.0015	0.06
PM_{10}	24-Hour	0.018	0.2
	Annual	0.0015	0.2

This analysis indicates that $PM_{2.5}$, and PM_{10} emissions from the project have predicted concentrations far below the corresponding Class I Area SILs at the nearest Class I Area. Moreover, even at a distance of 50 km from the Mockingbird Hill Compressor Station the results are below the Class I Area SIL. Hence, the concentrations would be expected to be even lower than those shown in the above table. As such, the project should not cause or contribute to an exceedance of the PSD Class I Increment levels for $PM_{2.5}$, and PM_{10}. Therefore, the requirements of 45 CSR 14-9. are satisfied with respect to the four Class I areas.

Class II Area SIL Analysis

The applicant conducted a Significant Impact Level (SIL) Analysis for Class II Area Increment and NAAQS. This type of analysis is used as a screening tool to eliminate the need to perform additional in-depth analysis that would requires the modeling to include emissions from background and increment consuming sources in the local area to satisfy the requirements of 45 CSR 14. The results of this screening analysis indicated that emissions from DETI's project are above the significant levels for $PM_{2.5}$ & PM_{10} for the 24-hour and annual .averaging periods Therefore, DETI conducted further analysis which included emissions from near-by sources and emissions from the existing sources at the Hastings Complex to demonstrate that the emissions associated with the project would not cause or contribute to an exceedance of the increment threshold under 45 CSR 14 nor cause or contribute to a violation of the NAAQS for PM_{10}, and $PM_{2.5}$. A summary of these results is presented in the following table.

Table #12 Summary of the Class II Screening Analysis

Pollutant	Averaging Period	Class II Area Maximum Modeled Concentration ($\mu g/m^3$)	
		SIL	Max Modeled Conc.
PM_{10}	24-hour	5	15.10
	Annual	1	3.24
$PM_{2.5}$	24-hour	1.2	12.87
	Annual	0.2	3.08

DETI conducted a NAAQS analysis and Increment Analysis to satisfy the requirements of 45 CSR §14-9.1. and 45 CSR §14-4.1.

NAAQS Analysis

DETI conducted a NAAQS analysis which included emissions from the Hastings Complex and Hastings Extraction Plant and from four other nearby facilities with the furthest facility being the Wetzel County Landfill which is 17.5 km away from the project.

The results of the NAAQS analysis predicts that there should be no exceedances of the NAAQS for PM_{10} and $PM_{2.5}$.

Table #13 NAAQS Analysis Results – Maximum Total Concentrations						
Pollutant	**Averaged Period**	**Modeled Max. Rank**	**Max. Modeled Conc. Design Value* ($\mu g/m^3$)**	**Background Conc. ($\mu g/m^3$)**	**Total Conc. ($\mu g/m^3$)**	**NAAQS ($\mu g/m^3$)**
$PM_{2.5}$	24-Hour	H8H Avg. over 5 yr	9.9	18.0	27.9	35
$PM_{2.5}$	Annual	1st High Avg. over 5 yr	3.2	8.4	11.6	12
PM_{10}	24-Hour	H6H over 5 yr	13.3	45	58.3	150

* - Max Modeled Conc. Design Values listed are based on the worst case of surface roughness, which was the Project Site.
H8H – High 8th High (form of the standard for the pollutant)
H6H - High 6th High (form of the standard for the pollutant)

45 CSR §14-9.1.b. required DETI to demonstrate that the project does not represent an impact above the applicable increment threshold established in 45 CSR §14-4.1. over Baseline concentrations.

"Baseline Concentration" is defined as the ambient concentration level which exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a minor source baseline date is established and includes:

> *The allowable emissions of major stationary sources which commenced construction before the major source baseline date, but were not in operation by the applicable minor source baseline date.*

Basically, the sources that began emitting emissions or made changes that affect the emissions after the Baseline date of the applicable pollutant are increment consuming sources and must be accounted for in the Increment Analysis. Like the NAAQS Analysis, DETI's Increment Analysis did not identified any exceedances of applicable Increment Levels. The following table notes the maximum concentration of increment consumed and the DETI's corresponding portion.

Table #14 Results of the Increment Analysis				
Pollutant	**Averaging Period**	**Allowable Increment ($\mu g/m^3$)**	**Max Model Contribution Design Value ($\mu g/m^3$)**	
			Airport Surface Roughness Run	**Project Surface Roughness Run**
$PM_{2.5}$	24-Hour	9	6.33	5.54
$PM_{2.5}$	Annual	4	0.92	0.89
PM_{10}	24-Hour	30	12.58	13.03
PM_{10}	Annual	17	2.77	3.24

DETI's NAAQS and Increment Analysis demonstrated that the project should not cause or contribute to an exceedance of the any NAAQS and allowable Increment level.

Class I Area Air Quality Related Values Analysis

45 CSR 14—13.6 allows applicants to make a demonstration to the Federal Land Manager(s) (FLMs) of the potentially affected Class I Areas that the emissions from the project would have no adverse impact on the air quality related values (AQRVs) of the lands in the Class I Area.

The Clean Air Act states that the FLMs are responsible for determining if an AQRV analysis for a Class I Area is necessary for a permit application that is subject to PSD (45 CSR14). To make such a determination, a "Q/d" analysis is typically used and accepted where "Q" is the emissions from the projected net increase from the project of NO_x, PM_{10}, SO_2, and sulfuric acid mist (H_2SO_4) in terms of tons per year. "Q" must be calculated using the maximum emission rate possible in any 24-hour operating period. "d" is the distance to the nearest Class I Area in terms of kilometers.

DETI determined the maximum emission rates on a 24-hour basis annualized from the project as follows:

- NO_x – 73.55 tpy
- PM_{10} (which includes condensable PM) – 30.28 tpy
- SO_2 – 5.07 tpy
- Total "Q" – 108.9 tpy

Otter Creek Wilderness Area, which is the closest Class I Area to the project site, is at 102 km from the Mockingbird Hill Compressor Station. Thus, the "Q/d" for this project is 1.1.

The corresponding FLMs of the four potentially affected Class I Areas were notified of pertinent details of this project on September 21, 2015. The DAQ was subsequently notified that no further analysis of AQRV for this project is necessary on September 21, 2015, from the U.S. Forest Service.

Additional Impacts Analysis

First, an assessment will be made regarding the amount of residential growth the proposed project will bring to the area. The amount of residential growth will depend on the size of the available work force, the number of new employees, and the availability of housing in the area. Associated commercial and industrial growth consists of new sources providing goods and services to the new employees and to the modified source itself.

DETI anticipates that the impact of the Mockingbird Hill Compressor Station is not expected to be significant. The project is expected to create approximately eight full time positions once the facility is constructed and operational. There is no need for additional infrastructure (upgraded roads, housing developments, etc.) to account for these new positions.

DETI notes that the results of the SILs and NAAQS analysis presented in the application demonstrates that the project will not have a significant impact on air quality in the region.

Class II Visibility Impairment Analysis

DETI has conducted a screening modeling analysis to estimate worst case visibility impacts for an observer located 5 km away from the Mockingbird Hill Expansion site. The intent of this analysis is to demonstrate worst case screening impacts in the vicinity of the project to satisfy the requirement of evaluating additional impacts to visibility under the PSD regulations.

A stack plume visibility screening analysis was performed based upon the procedures described in USEPA's Workbook for Plume Visual Impact Screening and Analysis. The screening procedure involves calculation of plume perceptibility (ΔE) and contrast (C) with the USEPA VISCREEN (Version 1.01, dated 13190) model, emissions of NOx and PM/PM10, worst-case meteorological dispersion conditions, and other default parameters as inputs. The screening procedure determines the light scattering impacts of particulates, including sulfates and nitrates, with a mean diameter of two micrometers (μm) and a standard deviation of two (2) μm. The VISCREEN model evaluates both plume perceptibility and contrast against two backgrounds, sky and terrain.

The VISCREEN model provides three (3) levels of analysis, the first two (2) of which are screening approaches. The Level-1 VISCREEN analysis was selected for the Project. The Level-1 VISCREEN assessment uses a series of default criteria values to assess the visible impacts. If the source passes the criteria defined for a Level-1 VISCREEN assessment ($\Delta E<2.0$ and $Cp<0.05$), potential for visibility impairment is not expected to be significant and no further analysis is necessary. If a source fails the Level- 1 criteria, more refined assumptions would be necessary. The analysis was performed assuming that all emitted particulate from the stacks would be PM10. The emissions of primary NO_2, soot, and SO_4 were set equal to the Level-1 VISCREEN default of 0.00 grams per second (g/s).

The VISCREEN Level-1 model results are summarized in table below. The calculated plume perceptibility and contrast parameters were determined to be below the VISCREEN default criteria for a visibility screening analysis for all screening criteria. Therefore, no additional visibility analysis was needed.

Table #15 Summary of the results of the VISCREEN Level 1 Analysis								
Background	**Theta[a] (degrees)**	**Azimuth[b] (degrees)**	**Distance (km)**	**Alpha[c] (degrees)**	**Perceptibility (ΔE)[d]**		**Contrast (C)[e]**	
					Criteria	**Plume**	**Criteria**	**Plume**
Inside Surrounding Area								
Sky	10	144	7	25	2.00	1.360	0.05	0.008
Sky	140	144	7	25	2.00	0.446	0.05	-0.008
Terrain	10	84	5	84	2.24	1.740	0.05	0.013
Terrain	140	84	5	84	2.00	0.242	0.05	0.006

a Theta is the vertical angle subtended by the plume
b Azimuth is the angle between the line connecting the source, observer, and the line of sight
c Alpha is the angle between the line of sight and the plume centerline
d Plume perceptibility parameter (dimensionless)
e Visual contract against background parameter (dimensionless)

The plume contrast depends on whether the product of the phase function and the albedo for the plume is larger or smaller than that for the background, the plume will be brighter (C > 0) or darker (C < 0) than the background horizon sky. Also note that the contrast is dependent on the plume optical thickness; as the plume optical thickness approaches zero, C approaches zero. Plume contrast also diminishes as the plume-observer distance rp increases.

For this demonstration, the model predicted a negative plume contrast with the sky with the Theta at 140^0, which means that the plume contrast is darker than the sky.

MONITORING OF OPERATIONS

Monitoring of the proposed Titan turbine should be focused on the different operating modes (i.e. normal, low load, low temperature, etc.) in terms of hours, power output and fuel consumed per month. The writer recommends monitoring the oxidation catalyst for each turbine to ensure it is at conditions that promote the oxidation reaction to occur and to detect build-up on the catalyst. The inlet temperature of the catalyst needs to be between 450 and 900 degrees Fahrenheit for the reaction to occur. It is recommended to monitor the inlet temperature on a continuous basis and record each instance the temperature is outside of this range and the mode the turbine was operating at during the occurrence. In addition, the pressure drop across the catalyst is required to be monitored monthly.

The emergency generator is a limited use emission unit under this permit to operate as an emergency stationary engine as defined under Subpart JJJJ of Part 60. The hours of the engine are operated shall be tracked through a non-resettable hour meter and the permittee shall note the purpose for the operation and track actual operation of the engine for non-emergency purposes.

The purpose of proposed the boiler is providing heat to the structures on an as needed basis during the heating season. The writer believes either tracking hours of operation or fuel usage on a monthly basis should be adequate in determining compliance with the established emission limits.

For demonstrating good combustion practices as BACT for the emergency generator and boiler, the permit requires these sources to be tune-up once every five years and records maintained of such tuned-ups. These sources are limited use emission units and requiring tune-ups any more frequently than once every five years would most likely not provide any additional benefit to the environment.

Other intermittent point sources of emissions are compressor blowdown vents, station emergency blowdown vent, and pig chamber (launcher/catcher) depressurization vents. The permit requires monitoring of these point sources to account for the emissions during the venting event.

The station is subject to the fugitive emissions of VOCs and GHGs due to equipment leaks at a compressor station as required under Subpart OOOOa. The permittee is required to develop and maintain a plan to monitor leaks at the station on a quarterly basis. Detected leaks must be repaired within 30 days of detection unless a shut-down is required for the repair then the repair can be delayed until the next planned shutdown or within 2 years, whichever comes first. Once a leak has been repaired, the repair must be verified within 30 days of completing the repair by conducting a follow-up survey of the repaired component.

Other monitoring being proposed in the draft permit comes from Subpart OOOOa, which requires the potential to emit of the Tank TK-001 to be based on the throughput of liquids from the first 30 days the vessel was placed into service. This requirement has been incorporated into the draft permit, with a reporting requirement should the potential to emit from the vessel exceed the 6 tpy of VOC control threshold.

PREFORMANCE TESTING

Emission testing on the proposed emission units will be limited to the combustion turbines and emergency generator. The turbines are subject to the NOx emission standard of Subpart KKKK. The regulation requires testing for NO_x within 180 days after startup and once every two years if the previous test demonstration shows the turbine was less than 75% of the NO_x emission standard. This permit is going to limit the NO_x rate just 36% of the standard. Therefore, the permit is going to set the subsequent testing frequency to every two years after the initial test.

The turbines will be relying on the oxidation catalyst to meet the proposed CO emission limit. The writer recommends conducting CO testing on the same frequency as required for NO_x.

The two turbines account for nearly all the PM generated due to the project. To verify and ensure that the established BACT Limit is met, testing for $PM/PM_{10}/PM_{2.5}$ needs to be conducted on the two turbines. Solar has published specific recommendations to minimize measurement related issues during such testing. The writer agrees with the published recommendations and incorporated them into the draft permit. Most of the potential PM from the turbines is the condensable fraction. The writer is requiring gas sampling of the fuel during the testing to measure the total sulfur present for the purposes of establishing a baseline for the fuel quality with regards to measured PM and to determine if quality is affecting the condensable PM based on changes in sulfur content of the fuel. Subsequent testing will be required once every five (5) years thereafter. The writer does not recommend any PM testing of the other sources since the sources contribution to the total PM is just over quarter of a ton per year.

The engine for the emergency generator is subject to Subpart JJJJ of Part 60 as a non-certified engine. Therefore, the regulation requires a compliance demonstration within 180 days after startup and because the engine has a power output greater than 500 hp, subsequent compliance testing is required once every 8,760 hours of operation or once every three (3) years, whichever comes first. DETI intends to operate this engine as an emergency use engine. Therefore, it is not anticipated that the engine would be operated for 8,760 hours in less than three years. Thus, the draft permit streamlined the criteria for the subsequent demonstration by only requiring subsequent testing once every three years.

RECOMMENDATION TO DIRECTOR

The information provided in the permit application indicates that the Mockingbird Hill Compressor Station should meet applicable requirements of state rules and federal regulations. It is recommended that DETI be granted a Permit for a Major Modification of a Major Source in accordance with 45 CSR 14 & 45CSR13 for the proposed expansion of the Mockingbird Hill Compressor Station.

Edward S. Andrews, P.E.
Engineer

May 3, 2018
Date

APPENDIX A

The Division of Air Quality Review

Of

Dominion Energy Transmission, Inc.

Air Quality Modeling Memo

To Support Permit Application R14-0033

MEMO

To: Ed Andrews
From: Jon McClung JDM
CC: Laura Crowder, Bev McKeone, Joe Kessler, Steve Pursley, Lee Yuchniuk
Date: January 25, 2018
Re: Air Quality Impact Analysis Review
Dominion Energy Transmission, Mockingbird Hill Compressor Station
PSD A lication R14-0033 - Plant ID#103-00006

I have completed my review and replication of the air quality impact analysis submitted in support of the PSD permit application (R14-0033) for the proposed modification of the Dominion Energy Transmission (DET), Mockingbird Hill Compressor Station located near Pine Grove, West Virginia, within Wetzel County. Review and replication of components of the modeling analysis were also performed by Ed Andrews, Joe Kessler, and Steve Pursley. The protocol for this modeling analysis was submitted by DET on September 1, 2015 and approved by West Virginia Division of Air Quality (DAQ) on December 14, 2015. The PSD permit application was received by DAQ on September 17, 2015, with an update to the permit application submitted on August 29, 2017. The revised modeling report was received in August 2017. This dispersion modeling analysis is required pursuant to §45-14-9 (Requirements Relating to the Source's Impact on Air Quality).

As part of the review process, an applicant for a PSD permit performs the air quality impact analysis and submits the results to the DAQ. The DAQ then reviews and replicates the modeling runs to confirm the modeling inputs, procedures, and results. This memo contains a synopsis of the modeling analysis. For a complete technical description of the modeling analysis, please consult the protocol and modeling analysis report submitted by the applicant.

DET proposes to modify the existing Mockingbird Hill Compressor station with the installation of two new combustion turbines (CT), an auxiliary boiler, and an emergency generator.

The emissions sources associated with the Project are:

Two (2) Solar Titan 130-20502S Combustion Turbines (CT), each rated at 20,500 bhp;
One (1) Auxiliary Boiler with a maximum heat input of 8.72 MMBtu/hr;
One (1) Caterpillar G3412C Emergency Generator, rated at 755 bhp;

This review is for the Class II area surrounding the proposed project site. Class I areas within 300 km of the project site are: Dolly Sods Wilderness (WV), Otter Creek Wilderness (WV), James River Face Wilderness (Virginia), and Shenandoah National Park (Virginia). The Federal Land Managers (FLMs) responsible for evaluating potential affects on Air Quality Related Values (AQRVs) for federally protected Class I areas were consulted. Based on the emissions from the proposed project and the distances to the Class I areas the U.S. Forest Service stated a Class I analysis for this project is not required. The National Park Service has not indicated a need for a Class I analysis. Attachment 1 contains the communications with the Federal Land Managers.

Wetzel County, WV is in attainment or unclassifiable/attainment status for all criteria pollutants. Pollutants emitted in excess of the significant emission rate (SER) are subject to PSD review in unclassifiable/attainment areas. The criteria pollutants that exceed the SER associated with the proposed project are in Table 1.

Table 1. Project-Related Significant Emissions Increases

Pollutant	Project Emissions (tons/yr)	PSD Significant Emission Rate (tons/yr)
PM_{10}	32.1	15
$PM_{2.5}$	32.1	10

Dispersion modeling was conducted for PM_{10} and $PM_{2.5}$. The modeled emission rates and stack characteristics for the Project are included in Attachment 2.

Table 2 presents a summary of the air quality standards that were addressed for PM_{10} and $PM_{2.5}$. The pollutants, averaging times, increments, significant impact levels (SILs) and National Ambient Air Quality Standards (NAAQS) are listed.

Table 2. Ambient Air Quality Standards, SILs, and PSD Increments (All concentrations in µg/m3)

Pollutant	Averaging Period	SIL	PSD Increments	NAAQS
PM_{10}	24-Hour	5	30	150
	Annual	1	17	-
$PM_{2.5}$	24-Hour	1.2	9	35
	Annual	0.2	4	12

An air quality impact analysis, as a part of the PSD review process, is a two tiered process. First, a proposed or modified facility is modeled by itself, on a pollutant-by-pollutant and averaging-time basis, to determine if ambient air concentrations predicted by the model exceed the significant impact level (SIL). If ambient impacts are below the SIL then the proposed source is deemed to not have a significant impact and no further modeling is needed. If ambient impacts exceed the SIL then the modeling analysis proceeds to the second tier of cumulative modeling.

The cumulative modeling analysis consists of modeling the proposed facility with existing off-site sources (and existing on-site sources, as applicable) and adding representative background concentrations and comparing the results to PSD increments (increment consuming and expanding sources only, no background concentration) and NAAQS. To receive a PSD permit, the proposed source must not cause or contribute to an exceedance of the NAAQS or PSD increments. In cases where the PSD increments or NAAQS are predicted to be exceeded in the cumulative analysis, the proposed source would not be considered to cause or contribute to the exceedance if the project-only impacts are less that the SIL.

On January 22, 2013, the U.S. Court of Appeals for the District of Columbia Circuit vacated two provisions in EPA's PSD regulations containing SILs for $PM_{2.5}$. The court granted the EPA's request to remand and vacate the SIL provisions in Sections 51.166(k)(2) and 52.21(k)(2) of the regulations so that EPA could address corrections. EPA's position remains that the court decision does not preclude the use of SILs for $PM_{2.5}$ but special care should be taken in applying the SILs for $PM_{2.5}$. This special care involves ensuring that the difference between the NAAQS and the representative measured background concentration is greater than the SIL. If this difference is greater than the SIL, then it is appropriate to use the SIL as a screening tool to inform the decision as to whether to require a cumulative air quality impact analysis. As shown in Table 3, for both the 24-hr and annual averaging time for $PM_{2.5}$, this difference is greater than the SIL and it is appropriate to use the SIL as a screening tool. Included in Attachment 3 are the WV $PM_{2.5}$ Design Values, Final and Certified.

Table 3. $PM_{2.5}$ NAAQS, Monitor Design Values, and Significant Impact Levels (All concentrations in $\mu g/m^3$)

$PM_{2.5}$ Averaging Period	NAAQS	Clarksburg Monitor Design Value (54-033-0003)	Difference between NAAQS and Monitored Design Value	Significant Impact Level (SIL)
		2014-2016		
24-hr	35	18	17	1.2
Annual	12	8.4	3.6	0.2

Modeling Basis

The modeling system used conforms to 40 CFR 51 Appendix W, applicable guidance, and the approved protocol and is summarized below:

- DET used the latest version of the regulatory dispersion model and supporting programs: AERMOD (version 16216r), AERMET (version 16216), AERMINUTE (version 15272), AERMAP (version 11103), AERSURFACE (version 13016), and

BPIP (version 04274). The AERMOD modeling system (AERMOD, AERMET, AERMAP) is the regulatory default modeling system for near-field (<50km) regulatory dispersion modeling.

- AERMET was used to process five years of surface meteorological data from the North Central West Virginia Airport (ICAO code: KCKB; WBAN Station ID 03802). Upper air data from Pittsburgh, PA (WBAN Station ID 94823) were used.
- AERSURFACE was used to develop appropriate surface characteristic (albedo, Bowen ratio, surface roughness) inputs to AERMET.
- A nested receptor grid was developed and AERMAP was used to determine terrain heights and hill height scales for use by AERMOD.
- Background 24-hour and annual $PM_{2.5}$ monitoring data were obtained from the Clarksburg, WV monitor (54-033-0003).
- Background concentrations for the 24-hour PM_{10} standard are from a monitor in Washington County, PA (ID #42-125-0005).

Modeling Operating Scenarios

The primary sources of emissions of $PM_{2.5}/PM_{10}$ are the two new proposed Solar Titan 130-20502S turbines. The emissions and stack characteristics for these turbines in Attachment 2 represent the turbines operating at full load. Typical operation of the proposed turbines will be at full load. The worst case emissions profile for $PM_{2.5}/PM_{10}$ for these units on a 24-hr basis and annual basis will be 24 continuous hours of operation at full load for every day of the year. Emissions of $PM_{2.5}/PM_{10}$ are not higher during scenarios of partial loads, startup, and shutdown. The worst case emissions scenario for the combustion turbines of full load operation is the scenario that was evaluated in the modeling analysis.

The Emergency Generator (Caterpillar G3412C) modeled emissions reflect 2 hours of operation in a 24 hour period. The permit application lists the hours of operation for the Emergency Generator as 500 hours/year.

The auxiliary boiler has a projected operating schedule in the permit application of 24 hours/day, 7 days/week, and 52 weeks/year. The modeled emission rate for the boiler is full load operation for the entire meteorological record.

SIL Analysis Results (Tier I)

The results of the Significant Impact Analysis for the DET Project sources are included in Table 4. DET performed the modeling analysis using surface characteristics from both the project site and the meteorological data collection site. The project site resulted in higher modeled concentrations and are shown in Table 4.

Table 4. SIL Analysis Results

Pollutant	Avg. Period	Maximum Modeled Conc. (µg/m^3)	Significant Impact Level (SIL) (µg/m^3)
$PM_{2.5}$	24-hour	12.87	1.2
	Annual	3.08	0.2
PM_{10}	24-hour	15.10	5
	Annual	3.24	1

Cumulative Analysis Results (Tier II)

The cumulative analysis includes the modeled impacts from the DET Project sources, DET non-project existing sources, nearby existing sources, and representative background concentrations. For off-site existing sources, the impacts represent maximum hourly potential emissions, as determined from applicable permits. The background concentration data is as summarized above with detailed information in the applicant's modeling report.

The cumulative analysis evaluated impacts at all receptors above the SIL in the SIL analysis. The SIL analysis is based on the highest-first-high concentration. The cumulative analysis is based on the form standard for each pollutant and averaging time. Table 5 shows the maximum total concentrations for all the receptors modeled in the cumulative analysis based on the Project Site surface roughness.

Table 5. NAAQS Analysis Results - Maximum Total Concentrations

Pollutant	Averaging Period	Maximum Modeled Concentration Design Value (µg/m^3)	Background Concentration (µg/m^3)	Total Concentration (µg/m^3)	NAAQS (µg/m^3)
$PM_{2.5}$	24-hour	9.9	18.0	27.9	35
	Annual	3.2	8.4	11.6	12
PM_{10}	24-hour	13.3	45	58.3	150

Tables 6 and 7 show the maximum total Class II Increment concentrations, which include maximum modeled concentrations from the DET Project and other increment consuming sources. Increment Analysis Results are presented for both the Airport Surface Roughness and Project Site Surface Roughness.

Table 6. Class II Increment Analysis Results - Airport Surface Roughness

Pollutant	Averaging Period	Maximum Modeled Concentration Design Value ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)
$PM_{2.5}$	24-hour	6.33	9
	Annual	0.92	4
PM_{10}	24-hour	12.58	30
	Annual	2.77	17

Table 7. Class II Increment Analysis Results - Project Site Surface Roughness

Pollutant	Averaging Period	Maximum Modeled Concentration Design Value ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)
$PM_{2.5}$	24-hour	5.54	9
	Annual	0.89	4
PM_{10}	24-hour	13.03	30
	Annual	3.24	17

Summary

The air quality impact analysis prepared and submitted by DET to the DAQ has been reviewed and replicated and conforms to 40 CFR 51 Appendix W, applicable guidance, and the modeling protocol. The cumulative modeling analysis demonstrates that no modeled exceedances of the NAAQS or Class II Increments are predicted.

ATTACHMENT 1

Federal Land Manager AQRV Determinations

Andrews, Edward S

From:	Kessler, Joseph R
Sent:	Monday, September 21, 2015 4:54 PM
To:	Andrews, Edward S
Subject:	FW: WV PSD Application Notification

From: Pitrolo, Melanie -FS [mailto:mpitrolo@fs.fed.us]
Sent: Monday, September 21, 2015 4:42 PM
To: Kessler, Joseph R
Cc: O'Dea, Claire B -FS
Subject: RE: WV PSD Application Notification

Thank you for keeping the USDA Forest Service informed about new or modified PSD facilities that may potentially impact Forest Service Class I Areas. Based on the proposed emissions from this project as well as the distance to the closest Class I Area managed by the Forest Service, it is not anticipated that the modified facility would cause or contribute to an adverse impact on any air quality related values (AQRVs) at any Forest Service Class I Area. Therefore, we will not be requesting any additional modeling be included as part of the application. Should the nature of the project change such that emissions increase, please let me know so that we may reevaluate the application.

Melanie

Melanie Pitrolo
Air Quality Specialist
Forest Service
Region 8, National Forests in North Carolina
p: 828-257-4213
f: 828-257-4874
mpitrolo@fs.fed.us
160 Zillicoa Street, Suite A
Asheville, NC 28801
www.fs.fed.us

Caring for the land and serving people

From: Kessler, Joseph R [mailto:Joseph.R.Kessler@wv.gov]
Sent: Monday, September 21, 2015 4:03 PM
To: O'Dea, Claire B -FS; Jackson, Bill -FS; Andrea Stacy (andrea_stacy@nps.gov); susan_johnson@nps.gov; Pitrolo, Melanie -FS
Cc: Andrews, Edward S; McKeone, Beverly D
Subject: WV PSD Application Notification

Hello, attached is the FLM information sheet for a new PSD application (major modification) submitted to the WVDAQ on 9/17/15:

R14-0033
103-00006
Dominion Transmission Inc.
Hastings/Mockingbird Compressor Station

Wetzel County, WV

According to information provided by the reviewing engineer, the facility will be over 100 km from all Class 1 areas and highest Q/D (emissions increase) is <1.

Thanks,

Joe Kessler, PE
Engineer
West Virginia Division of Air Quality
601-57th St., SE@ g
Charleston, WV 25304
Phone: (304) 926-0499 x1219
Fax: (304) 926-0478
Jose h.r.kessler wv. ov

ATTACHMENT 2

Emission Rates and Stack Characteristics

Table 2-1 Emissions and Stack Parameters – Proposed Project Sources and Existing Sources

Source	Facility	Model ID	Stack Height (ft.)	Exit Diameter (ft.)	Exit Gas Velocity (ft./sec)	Exit Gas Flow Rate (acfm)	Exit Gas Temp. (°F)	$PM_{2.5}/PM_{10}$ (lb/hr)	$PM_{2.5}/PM_{10}$ (tpy)
Project Sources									
Solar Titan 130 Turbine	Mockingbird - New	TRB1	50	7.5	96.0	254,464	900	3.46	15.16
Solar Titan 130 Turbine	Mockingbird - New	TRB2	50	7.5	96.0	254,464	900	3.46	15.16
Boiler	Mockingbird - New	AUXB	26	1.7	40.0	5,232	838	0.06	0.28
Caterpillar G3412 Emergency Generator[1,2]	Mockingbird - New	EGEN	13.2	0.7	187.5	3,927	793	0.005	0.003
AJAX DPC-2803LE Engine	Hastings - New	EN01	35	1.4	48.4	4,473	574	0.20	0.88
AJAX DPC-2802LE Engine	Hastings - New	EN02	35	1.4	30.7	2,836	577	0.14	0.61
Cooper GMXE6 Engine 1 removed[3]	Hastings - Old	XEN01	25	1.0	111.0	5,237	725	-0.18	-0.78
Cooper GMXE6 Engine 2 removed[3]	Hastings - Old	XEN02	25	1.0	111.0	5,237	725	-0.17	-0.74
Contemporaneous Sources									
Generac Model QT080 Natural Gas-Fired Emergency Generator (002-006)[1]	Hastings	AUX6	5	0.5	61.12	720	840	0.0018	0.0054
CAT 3612 Compressor Engine	Lewis Wetzel	EN03	45	1.0	505.24	23,809	838	0.55	2.43
Cummins KTA19G Aux. Generator	Lewis Wetzel	AZ05	10	1.0	66.21	3,120	1286	0.09	0.38
Bryan Model RV 450W-FDG Boiler	Lewis Wetzel	BLR5	18	0.7	269.97	5,711	838	0.06	0.26
Existing Sources									
Solar Taruus 60 Turbine	Mockingbird	TB02	50	4.0	145.89	110,000	900	2.69	11.78
Capstone C60 Microturbines / Aux. Generator	Mockingbird	AXG2	12	0.7	269.97	5,711	725	0.03	0.13
Capstone C60 Microturbines / Aux. Generator	Mockingbird	AXG3	12	0.7	269.97	5,711	725	0.03	0.13
Capstone C60 Microturbines / Aux. Generator	Mockingbird	AXG4	12	0.7	269.97	5,711	725	0.03	0.13
Boiler	Mockingbird	BLR2	18	0.7	269.97	5,711	838	0.04	0.18
Recip. Engine - Copper GMXE-6 (to be removed)	Hastings	XEN01	25	1.4	45.67	4,473	574	-0.01	-0.04
Recip. Engine - Copper GMXE-6 (to be removed)	Hastings	XEN02	25	1.4	45.67	4,473	574	-0.01	-0.04
Dehydration Unit Flare	Hastings	DEHY	17	0.7	33.09	700	950	0.03	0.13
Heater; Natco 96x30	Hastings	HTR1	24	2.0	42.44	8,000	725	0.08	0.35

Notes:
1 - Emergency Generator PM emissions reflect 2 hours of operation in a 24 hour period
2 - New Emergency Generator equipped and modeled with a stack cap
3 - Two engines, XEN01 and XEN02, were removed and replaced with EN01 and EN02. The removal of these two engines was only included in the SMC and $PM_{2.5}$ Increment analyses.

The primary project sources of emissions of $PM_{2.5}/PM_{10}$ are the two new proposed Solar Titan 130 turbines. The emissions and stack characteristics for these turbines presented in Table 2-1 represent the turbines operating at full load. Typical operation of the proposed turbines will be at full load. The worst case emissions profile for $PM_{2.5}/PM_{10}$ for these units on a 24-hr basis and annual basis will be 24 continuous hours of operation at full load for every day of the year. Accounting for scenarios involving partial loads or startup and shutdown

ATTACHMENT 3

Division of Air Quality $PM_{2.5}$ Design Values Report

West Virginia PM2.5
Design Values
data final and certified through 12/31/2016

		(NAAQS 24 hr 3 yr 98% = 35 ug/m³)													(Annual NAAQS <= 12.0 ug/m³)												
County	Site	02-04	03-05	04-06	05-07	06-08	07-09	08-10	09-11	10-12	11-13	12-14	13-15	14-16	02-04	03-05	04-06	05-07	06-08	07-09	08-10	09-11	10-12	11-13	12-14	13-15	14-16
Berkeley	Martinsburg	37	36	34	33	31	29	31	30	31	26	27	26	27	16.1	16.2	15.8	15.8	14.9	14.0	12.9	11.8	11.6	10.7	10.4	10.3	9.9
Brooke	Follansbee	44	42	40	37	37	34	31	27	27	26	24	25	22	16.5	16.8	16.4	16.4	15.4	14.4	13.7	13.0	12.7	11.6	11.1	11.2	10.5
	Weirton-Marl. Hgts	47	45	43	44	41	37	31	29	27	26	24	24	23	15.8	16.4	15.7	16.1	14.9	14.0	13.1	11.6	11.1	10.1	10.4	10.3	9.8
Cabell	Huntington	37	35	34	37	32	30	26	25	24	21	21	21	20	15.8	16.3	16.1	16.6	15.2	14.3	13.1	12.1	11.6	10.4	9.8	9.2	8.7
Hancock	Weirton-Summit Circle												22	21												9.7	8.8
	Weirton-Oak St.	44	41	40	41	38	35	31	28	27	26	23			17.0	16.6	15.4	15.2	14.3	13.4	12.4	11.7	11.3	10.5	10.0	10.0	9.8
Harrison	Clarksburg	34	32	35	34	31	26	23	21	21	20	19	19	18	13.6	13.9	13.9	14.2	13.4	12.5	11.8	10.6	10.2	9.2	9.1	8.8	8.4
Kanawha	Charleston	34	34	35	36	34	29	25	24	23	21	18	18		14.8	15.1	15.0	15.4	14.2	13.1	11.8	11.0	10.7	9.7	9.1	8.6	8.6
	Charleston NCore													14													7.6
	So. Charleston	36	36	37	38	36	32	28	26	24	22	20	20	19	16.4	16.6	16.4	16.6	15.4	14.4	13.2	12.5	11.9	10.8	10.2	9.6	9.0
Marion	Fairmont	36	34	34	34	32	28	26	26	25	22	19	19	18	14.8	15.0	14.9	15.3	14.5	13.6	12.9	12.1	11.6	10.3	9.7	9.4	8.9
Marshall	Moundsville	36	33	34	35	34	31	29	29	29	25	23	23	22	15.1	15.3	15.0	15.2	14.2	13.4	13.1	13.0	12.8	11.6	11.1	10.7	10.2
Monongalia	Morgantown	39	36	34	36	34	30	25	25	24	22	18	19	18	14.5	14.5	14.1	14.4	13.6	12.7	11.5	10.9	10.3	9.5	8.8	8.6	8.1
Ohio	Wheeling	35	32	31	32	31	29	26	26	25	24	22	23	20	14.7	14.9	14.2	14.6	13.7	13.2	12.4	11.9	11.6	10.6	10.4	10.3	9.6
Raleigh	Beckley	32	31	31	30	28	24	21	20	20	19	14	11		12.6	12.9	12.8	13.0	11.9	11.0	10.1	9.6	9.3	8.3	6.6	5.9	5.1
Wood	Vienna	35	34	35	37	34	31	28	27	24	22	19	21	19	15.2	15.4	15.3	15.4	14.6	13.7	13.1	12.3	11.8	10.4	9.8	9.4	8.9

* Summit Circle sampling started 1/1/2015; therefore 3 yr 98% not complete
Charleston NCore sampling started 1/1/2016; therefore 3 yr 98% not complete

Oak Street site shut-down 12/31/2014
Charleston site shut-down 12/31/2015

APPENDIX B

Copy of the Cost Analysis for GHG BACT

for

Carbon Capture and Sequestration

and

Vapor Gas Recovery Control Technologies

Submitted by

Dominion Energy Transmission, Inc.

Mockingbird Expansion Project
PSD Air Permit Application, GHG BACT Analysis
Cost Analysis - GHG Cost Effectiveness Summary for Carbon Capture and Sequestration
Combined Combustion Sources

	Post-Combustion CO_2 Capture and Compression	
Base Capture System Capital[1]	\$234.84/ton CO2 captured	\$53,125,552
Capital Cost for 3 Booster Stations	See Compression Cost Table	\$726,168
Annual O&M (fixed)[2]	\$5.81/ton CO2 captured	\$1,314,916
Annual O&M (variable)[2]	\$2.71/ton CO2 captured	\$612,474
Annual O&M for stations (fixed)[3]	See Compression Cost Table	\$29,047
Total Capital costs for capture & compression	Capture and Compression System + Booster Stations	\$53,851,720
Total Annual O&M costs	fixed + variable	\$2,564,867
	Incremental Utility Costs[2]	
CO2 Capture Units Steam Usage (10^3 lb)	3521.54 lb steam/ton CO2	648,600
Amine System Power Usage (kWe)	captured 47.59 kWe/ton CO2	10,765,114
Compressor Power Usage (kWe)	captured See Compression Cost	814,972
CO2 Capture Steam Cost [4]	Sheet	\$3,318,362
CO2 Capture Power Cost	\$4.16/MMBtu	\$699,437
	0.0604 \$/kWe	
	Pipeline Cost Breakdown[6]	
L, Pipeline Length (miles)		218
D, Pipeline Diameter (inches)		15
	Pipeline Costs	
Materials	\$70,350 + \$2.01 x L x (330.5 x D^2 + 686.7 x D + 26,960)	\$51,707,237
Labor	\$371,850 + \$2.01 x L x (343.2 x D^2 + 2074 x D + 170,013)	\$129,144,091
Miscellaneous	\$147,250+ \$1.55 x L x (8,417 x D + 7,234)	\$47,771,466
Right of Way	\$51,200 + \$1.28 x L x (577 x D + 29,788)	\$11,378,104
	Other Capital	
CO_2 Surge Tank	Fixed	\$1,311,593
Pipeline Control System	Fixed	\$117,919
	O&M	
Fixed O&M (\$/year)	\$8,454 x L	\$1,945,543
	Geologic Storage Costs[7]	
Number of Injection Wells		2
Well Depth (m)	Depth of formation[8]	1,825
Baseline CO_2 Captured (tons)	90% capture	184,181
CO_2 Generated for Capture & Compression (tons) [9]	117 lb CO2/MMBtu	46,711
CO_2 Captured including Amine Regeneration (tons)[10]	Baseline plus 90% CO_2 Generated for Capture & Compression	226,221
	Capital	
Site Screening and Evaluation	Fixed	\$5,355,300
Injection Wells	\$272,048 x $e^{0.0008 \text{ x Well Depth}}$	\$1,171,427
Injection Equipment	\$106,269 x (7,839/(280 x Number of Injection Wells))$^{0.5}$	\$397,596
Liability Bond	Fixed	\$5,000,000
	Declining Capital Funds	
Pore Space Acquisition	\$0.377/short ton CO2	\$85,393
	O&M	

Normal Annual Expenses	\$13,072/Injection Well*365	\$9,542,233
Consumables	\$3,385/yr/ton CO_2/day	\$2,097,881
Surface Maintenance	\$26,534 x (7,839/(280 x Number of Injection Wells))$^{0.5}$	\$99,275
Subsurface Maintenance	\$8.00/ft-depth/Injection Well	\$95,819

Annualized Cost Estimate	
Economic Life, years	20
Interest Rate (%)	7
Capital Costs	\$305,862,334
Annual O&M Costs	\$20,363,418
Capital Recovery	\$28,871,240
Total Annualized Cost	\$49,234,658
CO_2 Controlled (tpy)	184,181
CO_2 Cost-Effectiveness (\$/ton removed)	\$267

[1] Adapted from the "*Cost and Performance Baseline For Fossil Energy Plants*", DOE/NETL-2010/1397 from Exhibit 5-14 (pg 474) and Exhibit 524 (pg 497). Total Overnight Cost (TOC) adjusted using the ENR Construction Cost Index to 2014 dollars. To find capital cost (\$/tons CO_2 captured) the TOC of Case 14 less the TOC of Case 13 was divided by the tons of CO_2 captured to determine the added capital cost of a CSS.

[2] The total fixed and variable operating cost for Case 13 and 14 was adapted from the " *Cost and Performance Baseline For Fossil Energy Plants*", DOE/NETL-2010/1397. These values were located Exhibit 5-15 (pg. 475) and Exhibit 5-26 (pg. 498). The O&M prices were adjusted using the ENR Construction Cost Index from 2007 to 2014 dollars. To find the fixed O&M cost (\$/tons captured) the cost of Case 14 less the cost of Case 13 was divided by the tons of CO_2 captured. Utility costs were estimated by scaling steam usage from Exhibit 5-17 (pg. 478) and auxiliary load from Exhibit 5-18 (pg. 479) based on CO2 captured.

[3] Compression System costs estimated based on "*Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage and Correlations for Estimating Carbon Dioxide Density and Viscosity*" by UC Davis Institute of Transportation Studies pages 1-8.

[4] Based on the methodology presented in DOE/GO-102000-1115, "Benchmark on the Fuel Cost of Steam Generation". Assumes combustion efficiency of 81.7%. Additionally, O&M and Capital Recovery costs for the incremental steam demand has been estimated as ~50% of fuel cost.

[5] Electric cost for West Virginia from US eia's "Electric Power Monthly with Data for April 2014".

[6] Pipeline cost estimates based on "*Carbon Dioxide Transport and Storage Costs in NETL Studies*", DOE/NETL-2013/1614 (March 2013). Costs adjusted using the ENR Construction Cost Index to 2014 dollars.

[7] Geologic Storage cost estimates based on "*Estimating Carbon Dioxide Transport and Storage Costs*", DOE/NETL-2010/1447 (March 2010). Costs adjusted using the ENR Construction Cost Index to 2014 dollars.

[8] Average depth of targeted coal seams per SECARB's Central Appalachian Coal Seam Project "Summary of Field Test Site and Operations".

[9] Based on additional steam demand and the emission factor for NG combustion from 40 CFR 98, Table C-1 to Subpart C.

[10] Assumes that additional emissions generated by the capture system are controlled.

Compressor Power Calculations

General Parameters

R =	8.314 kJ/kmol-K
M =	44.01 kg/kmol
T in =	69 F
Tin =	293.56 K
ηis =	**0.75**
CR =	2.15 per stage

Stage 1		
	Zs1 =	0.995
	ks1 =	1.277
	Ws1 =	438.3908451
Stage 2		
	Zs2 =	0.985
	ks2 =	1.286
	Ws2 =	434.9195516
Stage 3		
	Zs3 =	0.97
	ks3 =	1.309
	Ws3 =	430.6024463
Stage 4		
	Zs4 =	0.935
	ks4 =	1.379
	Ws4 =	421.46033
Stage 5		
	Zs5 =	0.845
	ks5 =	1.704
	Ws5 =	402.4788621
Total Compressor Power		
	Ws 1-5 =	2,128 kW
	N trains =	1
Pump Power Calculation		
	CO2 mass captured =	620 ton/day
	CO2 mass captured (m) =	562 tonnes/day
	Pinitial =	0.162 MPa
	Pfinal	**15** MPa
	Pcut-off =	7.38 MPa
	ρ =	**630** kg/m^3
	Nstages	5
	ηρ =	**0.75**
	Wρ =	105 kW
Total Transport Power		
	Pump + Compressor =	2,233 kW
		814,972 kWe

Initial Compression/Pumping Cost		
Capital Cost		
	m train =	6.51 kg/s
	Capital cost of compressor = $	14,968,710 2014 $
	Capital cost of pump = $	242,056 2014 $ Total
	Capital $	15,210,766 2014 $

O&M cost	
Annual O&M $	608,430.64 2014 $
Electricity Cost	
price of electricity 0.0604 $/kWh annual electricity $ 945,107 $/yr	
Compressor Booster Stations (3 needed)	
Pump Power Calculation	
CO_2 mass captured =	620 ton/day
CO_2 mass captured (m) =	562 tonnes/day
Pinitial =	8.10 MPa
Pfinal	**15** MPa
Pcut-off =	7.38 MPa
ρ =	**630** kg/m^3
nρ =	**0.75**
Wρ =	105 kW
	38,306 kWe
Total Pumping Cost for Booster Stations	
Capital Cost	
Capital cost of pump 2005 = $	186,493 2005 $
Total capital (1 station) = $	242,056 2014 $ Total
Capital (3 stations) = $	726,168 2014 $
O&M cost	
Annual O&M (1 station) $	9,682 2014 $
Annual O&M (3 stations) $	29,047 2014 $
Electricity Cost	
price of electricity 0.0604 $/kWh annual electricity $ 44,423 $/yr	

Gas blown down to Atmosphere per event	34.7 tons CO2e
Events per year per unit	100
# of Units	2
Total potential emissions from blowdowns per year	**6936.3 tons CO2e**

3/8/2017

Mockingbird Compressor Station - Addition of Two Titan 130 Compressors Calculation to find volume of gas vented to atmoshphere for a typical blowdown

Process Conditions

Initial Temperature	50 Deg F
Initial Pressure	800 PSIG
Absolute Temperature	510 Rankine
Absolute Pressure	814.7 PSIA
Volume of Unit and Piping	1330 Cubic Ft

Standard Conditions

Atm Absolute Temperature	520 Rankine
Atm Absolute Pressure	14.7 PSIA
Number of Unt Volumes Vented during Purge (S/U)	1.5

Amount of Gas Released Per Blowdown

Volume of Gas to Atmosphere during purge	1995 SCF
Total Volume of Gas in Unit at start of shut down	75156 SCF
Total Volume of Gas at end of event	1356 SCF
Gas blown down to Atmosphere	75795 SCF
	196.62 lbmols of gas

Gas Composition (User Inputs):

Component	% of Total
Methane	**88.175**
Ethane	**10.299**
Propane	**0.537**
Isobutane	**0.053**
N-Butane	**0.113**
N-Hexane	**0.088**
Nitrogen	**0.541**
Carbon Diox	**0.194**
Water	**0.000**
Total:	100.000

CH4	173.4 lbmols
	2773.8 lbs
	1.4 tons
	34.7 tons CO2e

CO2	0.4 lbmols
	16.78 lbs
	0.01 tons

Client: DOMINION TRANSMISSION INC. VENT GAS RECOVERY COMPRESSOR Project: MOCKINGBIRD HILL COST BENEFIT ANALYSIS

From Engineering Vendor:

Basic Job No. 1933

Summary of **Estimated Capital** Costs Associated with Vent Gas Recovery (VGR) Installation:

Contractor Cost for Field Work: **$150,000**

Cost of Vent Gas Recovery Skid: **$288,200**

Cost of Pipe and Fittings Needed for Operation: **$900** Cost of Valves and Actuators Needed for Operation: **$48,550**

Cost of Electrical Components Needed for Operation: **$41,270**

Cost of Detailed Engineering: **$50,000**

Cost of Compressor Building Expansion to accommodate VGR System: **$142,360**

Miscellaneous Items **$0**

Sub-Total: $721,280 Contingency

15.0%

Total $829,472

ELECTRICAL COST INCLUDES
AN ESTIMATED $20,000 FOR THE INCREMENTAL ADD'L COST TO THE DTI CMPR BLDG SCP REMOTE I/O PANEL

Above data is used to populate OAQPS Cost Analysis to determine Total Annualized Costs For OAQPS - Red items above considered to be "Basic Equipment" purchased equipment costs.

Dominion Transmission, Inc.
GHG BACT Assessment
Mockingbird Hill Compressor Station
West Virginia

Station	**Mockingbird Hill Compressor Station**		
Unit Name	**Blowdowns from Titan 130 Turbines** *(Note - Emission Rate updated from Application to match updated Engineering Estimates)*		
Unit Description	**Natural gas-fired simple cycle turbine**		
Make/Model	**Solar Titan 130**		
Size	**21765**	**hp (each)**	
Pollutant	**GHG (CO2e)**		
Current Emission Rates		**6,936 tpy**	*(Emission Rate updated from Application to match updated Engineering Estim*
Max. Operating Schedule	**8760**	**hours**	
Control Device Reviewed	**Capture and recompress blowdown gas**		
Control Efficiency	**95%**		

	COST COMPONENT:	ABBREV.	COST ($1,000)	SOURCE[1]	CALCULATION
DIRECT COSTS					
	Purchased Equipment Costs				
	Basic Equipment				
	Instrumentation (INCLUDED IN ABOVE COSTS)	BE			
	Tie-ins / Controls for Captured Gas				
	Taxes and Freight		521		
	Subtotal - Purchased Equipment Costs		---	Vendor	
		PEC	0	Vendor	
	Direct Installation Costs Foundation		42	Estimate	0.08 x BE
	& Supports		**563**	OAQPS	
	Handling and Erection				
	Insulation				
	Painting		45		0.08 x PEC
	Subtotal - Direct Installation Costs		79	OAQPS	0.14 x PEC
		DIC	5.6	OAQPS	0.01 x PEC
TOTAL DIRECT COSTS			5.6	OAQPS	0.01 x PEC **PEC**
		DC	**135**	OAQPS	
INDIRECT COSTS					
			698		**+ DIC**
	Engineering				
	Construction & Field Expenses				
	Contractor Fees				
	Start-Up		50		
	Performance Testing		28.1	Vendor	0.05 x PEC
	Contingencies		150	OAQPS	
TOTAL INDIRECT COSTS			11.3	Vendor	
			5.6	OAQPS	0.02 x PEC
			16.9	OAQPS	0.01 x PEC
		IC	**262**	OAQPS	0.03 x PEC
TOTAL CAPITAL INVESTMENT		**TCI**	**960**		**DC + IC**

 Dominion Transmission, Inc.
GHG BACT Assessment
Mockingbird Hill Compressor Station
West Virginia

COST COMPONENT:	CODE	COST ($1,000)	SOURCE[1]	CALCULATION

					0.15 x OP
DIRECT ANNUAL COSTS					1.00 x LAB
Operating and Maintenance Costs					
Operator					
Supervisor					
Labor			3.3		
		OP			
Material			0.5		
				OAQPS[2]	**O&M + UTIL + CAT**
Subtotal - Operating and Maintenance Costs			3.6		
		LAB			
			3.6	OAQPS	
Utility Costs[4]			**11**	OAQPS[3]	
		O&M		OAQPS	
					0.60 x O&M
			30		
		UTIL			0.02 x TCI
TOTAL DIRECT ANNUAL COSTS					
					0.01 x TCI
				Estimate	
			41		0.01 x TCI
INDIRECT ANNUAL COSTS					
		DAC			ACF x TCI
Overhead					
Administrative					
Insurance			6.6		
Property Tax			19.2		
Capital Recovery			9.6	OAQPS	
Period (years)			9.6	OAQPS	
Interest Rate (%)			137	OAQPS	
Annualized Cost Factor [6]				OAQPS	
				OAQPS	
TOTAL INDIRECT ANNUAL COSTS	*10*			OAQPS	
	7	ACF		OAQPS	
	0.14	**IAC**	**182**	OAQPS	
TOTAL ANNUAL COSTS		**TAC**	**223**		**DAC + IAC**
CO2e Emission Rate			**6936.30**	**tpy**	
CO2e Removed			**6589.48**	**tpy**	
Cost Effectiveness			**$ 34**	**$/ton**	

NOTES:

1. Sources are as follows:
   - -Estimate: Best engineering judgement
   - -OAQPS: EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Section 3.1
2. Labor costs assume $12.00 per hour, 15 minuntes per shift, 1,095 shifts per year (8 hour shifts)
3. Labor costs assume $13.20 per hour, 15 minuntes per shift, 1,095 shifts per year (8 hour shifts)
4. Utility Costs - Operation of gas recovery equipment
6. Annual Cost Factor = [Interest Rate * (1 + Interest Rate) ^ (# of years)] / [(1 + Interest Rate) ^ (# of years) - 1]