Consumers Energy Company

RESPONSE TO COMMENTS DOCUMENT

July 25, 2013

PERMIT No. 191 -12

Rick Snyder, Governor

Air Quality Division
Michigan Department of Environmental Quality

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I. PUBLIC PARTICIPATION PROCESS

Permit to Install application No. 191-12, for Consumers Energy Company (CECo), is for the proposed installation and operation of a new natural gas-fired electricity generation facility. The facility will include up to four combustion turbines with duct burner fired heat recovery steam generators (HRSG), two black start simple cycle peaking units, two auxiliary boilers, two fuel gas heaters, a limited use diesel engine fire pump, and other ancillary equipment. The facility will be located at 10500 North Genesee Road, Mt. Morris, Michigan. The public participation process involved providing information for public review including a Fact Sheet, proposed permit terms and conditions, a public comment period, and the receipt of written public comments on staff's analysis of the application and the proposed permit.

On May 17, 2013, copies of the Notice of Air Pollution Comment Period and Public Hearing, the Fact Sheet, and the draft terms and conditions were placed on the Department of Environmental Quality (DEQ or Department), Air Quality Division (AQD) Home Page (http://www.michigan.gov/air). In addition, a notice announcing the Public Comment Period, Public Informational Meeting, and Public Hearing, if requested was placed in the Flint Journal. The notice provided pertinent information regarding the proposed action; the locations of available information; a telephone number to request additional information; the date, time, and location of the Public Informational Meeting and Public Hearing, if requested; the closing date of the Public Comment Period; and the address where written comments were being received.

A public hearing was not requested. Two letters containing written comments were received during the Public Comment Period. One was from US EPA and the other was from the Sierra Club.

EPA's comment No. 10 resulted in changes to the special conditions (SCs) for the emergency fire pump in the final permit. The comment and response are presented later in this document. SC I.4 and SC I.5 were changed to 0.14 pound per hour; SC III.1 now includes a restriction on operation of the emergency fire pump 6 hours per day; and SC VI.3 now requires daily records of the hours of operation. The revised conditions are presented here:

I. EMISSION LIMITS

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Testing / Monitoring Method	Underlying Applicable Requirements
1. NMHC + NOx	3 g/hp-hr	Test protocol will specify averaging time.	EUFPENGINE	SC V.1, SC VI.2	R 336.1205(1)(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(c) & (d), 40 CFR 60.4205
2. CO	2.6 g/hp-hr	Test protocol will specify averaging time.	EUFPENGINE	SC V.1, SC VI.2	R 336.1205(1)(a), R 336.2804, R 336.2810, 40 CFR 52.21(d)
3. PM	0.15 g/hp-hr	Test protocol will specify averaging time.	EUFPENGINE	SC V.1, SC VI.2	R 336.1205(1)(a) R 336.1224, R 336.1331(1)(c), 40 CFR 60.4205
4. PM10	0.14 lb/hr	Test protocol will specify averaging time.	EUFPENGINE	GC 13 SC VI.2	R 336.1205(1)(a) R 336.2803, R 336.2804, R 336.2810 40 CFR 52.21(c) & (d)
5. PM2.5	0.14 lb/hr	Test protocol will specify averaging time.	EUFPENGINE	GC 13 SC VI.2	R 336.1205(1)(a), R 336.2803, R 336.2804, R 336.2810, 40 CFR 52.21(c) & (d)
6. GHGs as CO_2e	15.6 tpy	12-month rolling time period as determined at the end of each calendar month	EUFPENGINE	SC VI.5	R 336.1205(1)(a), R 336.2810

III. PROCESS/OPERATIONAL RESTRICTIONS

1. The permittee shall not operate EUFPENGINE for more than 6 hours per day, except during emergency operations, and not more than 100 hours per year on a 12-month rolling time period basis as determined at the end of each calendar month. **(R 336.1205(1)(a) & (3), R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, 40 CFR 52.21 (c) & (d))**

VI. <u>MONITORING/RECORDKEEPING</u>

3. The permittee shall monitor and record the hours of operation of EUFPENGINE during emergencies and non-emergencies, on a daily, monthly and 12-month rolling time period basis, in a manner acceptable to the AQD District Supervisor. The permittee shall record the time of operation of EUFPENGINE and the reason it was in operation during that time. The permittee shall keep all records on file and make them available to the Department upon request. **(R 336.1205(1)(a), 40 CFR 60.4211, 40 CFR 60.4214)**

The remainder of this document is a listing of the significant comments received during the public comment period regarding the proposed permit and the Department's responses.

II. SUMMARY OF SIGNIFICANT COMMENTS

A. EPA Comments

Comment

1. The GreenHouse Gas (GHG) Best Available Control Technology (BACT) analysis for the combined cycle turbine generators in the permits' Fact Sheet proposes GHG BACT as a heat rate limit of 7,460 British thermal units per kilowatt hour (BTU/KW-hr) (net) corresponding to 873 pounds (lbs) Carbon Dioxide Equivalents (CO_2e)/MegaWatt Hour (MWh) net output, and 1,334,965 tons of CO_2e per year for Technology A. The draft permit only proposes the 1,334,965 tons of CO_2e per year limit for Technology A. Please consider adding the proposed BTU/KW-hr GHG BACT limits as permit conditions for the combined cycle turbine generators as well as the corresponding lbs of CO_2e/MWh limits because that will help reflect the efficiency of the turbines.

AQD Response

The permit limits emissions at rates that are enforceable and achievable over the expected range of operating conditions to be encountered during the operating life of the equipment. GHG emissions are products of fuel combustion. The idea of energy efficiency has always been a primary consideration in the electricity generation industry because more efficient use of energy (efficient combustion) equals higher profits and lower emissions at the same time.

There are many design variables in the electricity generating part of the process. For example, a design or work practice that may be best for a baseload operation with few startup/shutdown cycles may not be the best choice for a peaking unit which requires a wider range of operating scenarios. Energy efficiency is not the only consideration in the design of an electricity generating facility. Other concerns include equipment reliability, maintenance, and site-specific factors such as the availability of water for example, which was important at the Thetford Township site.

The fuel combustion process is the primary source of emissions. Limiting the emissions based on the heat input rate removes many design variables from the calculation and provides a directly measurable methodology for enforcement of the emission limits. The permit goes beyond limiting the GHG emissions on a heat input basis as described in the comment. For the Technology A example used in the comment, Special Condition IV.3 on page 26 specifies operating parameters for the heat input calculation as follows:

> The net heat rate for each CTG/HRSG pair (2x1 Block), EUCTGHRSG1A plus EUCTGHRSG2A combined or EUCTGHRSG3A plus EUCTGHRSG4A combined, shall not exceed 7,460 Btu/kW-hr (HHV-net) at the following reference conditions: ambient temperature of 59°F, 60% relative humidity, ambient pressure at the mean site elevation, baseload operation without duct firing, and not accounting for transformer losses. **(R 336.1205, R 336.2810)**

AQD has intentionally defined the GHG BACT emissions in terms of the measurable heat input rate to the combustion process. Output based limits are not specified in the applicable regulations.

Comment

2. The GHG BACT analyses for the Auxiliary Boilers, Peaking/Black Start Simple-Cycle Combustion Turbines, Fuel Heaters and Emergency Fire Pump are not included in the draft permit's Fact Sheet. Page 26 of the Fact Sheet states that those BACT analyses are in the permit application file and are available for public review, but to ensure consistency with all the GHG emission sources, and to make the draft permit's Fact Sheet more complete, please include those GHG BACT analyses in the Fact Sheet.

AQD Response

The Fact Sheet is intended to be a summary of the permit application and the AQD review of the application. The largest emission sources, the four CTG/HRSG trains will produce 99.3 % of the GHG emissions from the proposed project and are discussed in more detail in the Fact Sheet than those mentioned in the comment. While some details were left out of the Fact Sheet, they were available for review by those who desired a "more complete" description of the proposed facility. Prior to the start of the Public Comment period, AQD posted an electronic copy of the complete PTI application at http://www.deq.state.mi.us/aps/downloads/permits/Consumers/191-12.htm. Section 5.8 of the application discussed the GHG BACT, including the Auxiliary Boilers, Peaking/Black Start Simple-Cycle Combustion Turbines, Fuel Heaters and Emergency Fire Pump.

Comment

3. The permit application lists "energy efficiency" as GHG BACT for the two Peaking/Black Start simple-cycle combustion turbines and auxiliary boilers. Please add to the BACT analysis what specifically those "energy efficiency" measures are, and add the BACT analysis to the draft permit's Fact Sheet.

AQD Response

Energy efficiency for simple cycle combustion turbines and auxiliary boilers is dominated by the equipment's net heat rate, or its ability to convert energy content in the fuel to useful electric power or steam, reduced by the amount of electricity needed in the conversion process or other energy losses. For the simple cycle CTGs, the term "energy efficiency" directly refers to the expected net heat rate of the equipment at site conditions. To maximize energy efficiency, selection of the simple cycle CTGs by CECo will be based on acquisition of equipment that possesses necessary minimum generating capability with a net heat rate reflective of the best performing units. This equipment typically employs elevated firing temperatures, staged combustion controls, insulation, and gas or inlet air preheating. The draft PTI conditions were based on performance and emissions associated with a CTG net heat rate and thermal efficiency of nominally 10,500 Btu/kWh LHV and 32% LHV. Commercially available CTG equipment meets the design criteria including these minimum requirements.

Similarly, the purpose of the auxiliary boilers is to provide steam for heating and motive purposes (not power generation) and this equipment will operate on an as-needed basis. Boiler efficiency (net heat rate) and minimization of NO_x and other emissions through low NO_x combustors are key components of boiler procurement. Higher boiler efficiency is accomplished through heating the incoming feedwater, air/fuel ratio controls, and insulation and other materials to reduce thermal losses. The draft PTI conditions were based on a boiler efficiency of 82% which is consistent with commercially available gas-fired, water tube boilers of the required steaming capability and noted efficiency improvements.

Comment

4. GHG BACT The permit application's GHG BACT analysis for the two Peaking/Black Start simple-cycle combustion turbines shows a ton per year of CO_2e as the chosen BACT limit. To better reflect the efficiency of the turbines, please consider also including a lbs of CO_2e/MWh GHG BACT limit for those turbines.

AQD Response

As the comment notes, the proposed permit includes a BACT emission limit for GHG emissions from FGPEAKERS. The Fact Sheet and permit record illustrate that AQD selected a limit of 20,141 tons CO_2e per 12-month rolling time period applied on a per unit basis as BACT for the Peaking/Black Start simple cycle combustion turbines. This was because AQD agreed with CECo's analysis which showed that this limit is representative of efficient operations and can be enforced as a practical matter with a fuel heat input limitation and records of fuel combustion. AQD has considered other BACT limitations and does not believe that an additional BACT limit is necessary for the Peaking/Black Start simple-cycle combustion turbines. This equipment represents less than 1% of the total proposed GHG emissions from the project.

Comment

5. If the gas turbines will have circuit breakers insulated with Sulfur Hexafluoride (SF6), please include a top-down BACT analysis in the draft permit's Fact Sheet for those GHG emissions.

AQD Response

The project gas turbines will be equipped with lower voltage generator circuit breakers that do not require sulfur hexafluoride (SF6) gas insulation. The current Thetford Generating Station (TGS) design does include a maximum of ten 345 kV circuit breakers (CBs) to be located in the TGS Switchyard and those CBs will be insulated with SF6. The use of such CBs is typical to the utility industry. SF6 has superior insulating and arc-quenching capabilities over limited other alternatives.

Unlike other equipment being permitted, emissions associated with circuit breakers are not by design but are unintentional losses of product that CECo is incentivized to prevent regardless of environmental requirements. SF6 losses due to CB leakage during commissioning and once placed into service are very small and, although its GWP is high, combined SF6 losses are not a major contribution to global warming. For circuit breakers and other gas-insulated components, SF6 emissions are greatest during infrequent CB maintenance activities than they are in-service. Expected annual leakage from typical new CBs purchased today is expected to range between 0.1 and 0.5% of the contained volume of each CB. Today's CB designs are equipped with SF6 pressure detection and are continuously monitored to enable response to a detected leak to prevent loss of complete inventory. The operational reliability and the service life of an SF6-insulated circuit breaker is very much dependent on sealing of the SF6 gas volume and neutralizing the effects of moisture and decomposition products in the gas. Industry experience has shown that SF6 leakage is negligible when double nitrile rubber O-rings and X-rings have been included in CB design, and these design elements will be included in the TGS project specifications.

Leak detection is effectively minimized by pressure monitoring and annunciation back to the Distributed Control System (DCS) via the switchyard control building, with SF6 pressure typically in the range of 14 to 130 psi (0.1 to 0.9 MPa) in the CBs. There is no specific insulating concern even if the pressure fully decays, although it is anticipated that CEC station personnel would respond to any pressure decay before a total SF6 loss event. CB manufacturers understand the GHG potential of SF6 and have continually improved their products to minimize losses. Refilling of the CBs is typically accomplished by SF6 cylinders and leakage during these events is very small.

The carbon dioxide equivalency (CO_2e) for SF6 gas is obtained by multiplying the mass and the Global Warming Potential (GWP) of the gas. A GWP value of 23,900 is consistent with 40 CFR Part 98, Subpart A, Table A-1 and was endorsed by the Intergovernmental Panel on Climate Change (IPCC) in 2007 for a 100-year potential period.

Typically, the quantity of SF6 gas in each 345 kV CB will be less than 200 pounds when full. The maximum quantity of SF6 at the TGS would therefore be ten CBs times 200 pounds or a total 2,000 pounds of inventory at the TGS site. Using a maximum industry leakage rate of

0.5% for new CBs against the total SF6 inventory in the TGS CBs, the leakage would equate to 2,000 x 0.5/100 or 10 pounds per year (0.005 tons/year). This equates to a carbon dioxide equivalent (CO2e) of 119.5 tons per year (tpy) of CO_2e, which is very small even at the maximum industry-observed leakage rates used in this estimate.

A top-down BACT analysis would identify two methods for reducing or eliminating SF6 emissions:

1. Replace SF6 insulating media in the CBs with another insulator; and
2. Design CB insulation systems to minimize SF6 leakage.

Replacement of SF6 with another non-GHG insulating media (e.g., dielectric oil or compressed air) in 345 kV CBs is not technically feasible. This is the best technology available for controlling GHG emissions and has been selected for this project.

Comment

6. Please account for any methane and carbon dioxide fugitive GHG emissions from the natural gas piping components, and include a top-down BACT analysis in the draft permit's Fact Sheet for those GHG emissions.

AQD Response

Similar to the response above on circuit breakers, fugitive emissions of GHG are not by design but are unintentional losses of product that CECo is incentivized to prevent regardless of environmental requirements.

The natural gas planned for use at the TGS is expected to be 95.7% methane and 1.4% carbon dioxide by molar percentage. This gas will be supplied under relatively high pressure via an underground pipeline that exists at the site. Gas leaks from valves, compressor seals, flanges, filter drains, pressure relief valves, and other process and operation components are possible and the methane and carbon dioxide represent fugitive GHG emissions. Normally, the entire system pressure boundary is intact and there are no fugitive emissions. However, inadvertent leaks and maintenance activities can occur and are dependent on the type and number of equipment "components" and the leak rate of those components. Compressors, valves, pressure relief valves, flanges, and instrumentation are potential sources that can leak due to seal failure. Other sources of natural gas inventory loss, such as from sampling connections during use or periodic venting associated with CTG unit startup or line pigging, may contribute to TGS emissions. In addition, corrosion of welded connections, flanges, and valves over time without proper maintenance can also enable natural gas leakage emissions.

The complete natural gas supply system for the CECo facility has not been designed and so the presence of system components and joints that can yield gas leaks and fugitive emissions have not been fully defined. The following table contains an estimate of emissions:

Thetford GS Natural Gas Piping – Fugitive Emissions				
Component Group	**Fluid**	**Emission Factor (Note 1)**	**Number of Components**	**Annual Fugitive Emissions (tpy) (Notes 2 & 3)**
Valves	Natural Gas (HP)	0.0132	90	5.2
Flanges	Natural Gas (HP)	0.0039	300	5.1
Compressors	Natural Gas (HP)	0.5027	2	4.4
Relief Valves	Natural Gas (HP)	0.2293	8	8.0
Open End Connections	Natural Gas (HP)	0.0038	0	0
Sample Connections	Natural Gas (HP)	0.033	4	0.6
Others	Natural Gas (HP)	0.07	4	1.2
Process Drains	Natural Gas (HP)	0.07	2	0.6
Totals			410	25.2
Percentage as Methane				95.7
Percentage as Carbon Dioxide				1.4
Methane Emissions				**24.1**
Carbon Dioxide Emissions				**0.4**
Total CO2e Emissions				**506**

Notes:

1. Multiple different emission factors considered. Listed values are average Synthetic Organic Chemical Manufacturing Industry (SOCMI) leakage values extracted from Factors taken from EPA document EPA-453/R-95-017; November, 1995. Factors are in lb/hr/component.
2. Conservatively calculated on the basis of leakage being possible from all sources on a continuous 8,760 hour per year basis. Many sources will not be exposed to full-year gas pressurization and leakage.
3. The CO_2e emissions are based upon a methane Global Warming Potential of 21 consistent with 40 CFR Part 98, Subpart A, Table A-1.

From a top-down BACT perspective, the only viable solutions are to replace all natural gas delivery system components and potential fittings with welded connections or sealed subsystems to prevent leaks. This approach is generally not construed to be possible given the types of processing equipment involved. AQD considered including BACT limitations for GHG fugitive emission from the natural gas piping components and does not believe that it is appropriate, as this equipment represents less than 0.1% of the total GHG emissions associated with the facility.

Comment

7. The Fact Sheet does not specify what particular technologies (A or B) Consumers Energy Company intends on potentially utilizing for its project. The draft permit and Fact Sheet only provide a general description of the equipment to be installed. Please include a general description of each of the potential technologies in the Fact Sheet.

AQD Response

AQD evaluated the description of the associated technology options contained within the Fact Sheet and the PTI application submittal, which prior to the start of the Public Comment Period was posted on the internet at http://www.deq.state.mi.us/aps/downloads/permits/Consumers/191-12.htm. Sufficient information was provided for the permit to have been written. In particular, Section 2.0 of the PTI application entitled "Process Overview" provides a detailed description and analysis of all the technologies associated with the project. Section 2.1.1 states:

"Four identical natural gas-fired combined-cycle CTGs – These units will be divided into two 2x1 power blocks. Each CTG is nominally rated at 211-230 MW (depending on manufacturer) of gross electrical power output at ISO conditions (59°F, 60% relative humidity and 14.696 psia). To provide flexibility in meeting future load demands, each CTG unit will be coupled to an HRSG that is capable of un-fired and fired operating modes. Within each 2x1 power block, the two HRSGs generate steam for a single steam turbine (ST). CECO has not yet gone out to bid on major equipment. Selection of specific CTG models will affect the sizing of the associated duct burners necessary to achieve the design plant output, expected mass emissions at baseload operation and during startup and shutdown, etc. In recognition that final CTG selection has not been made, this application is based on evaluation of two possible CTG models within the size range necessary to achieve design plant output, with the two models designated as Technologies A and B throughout the application. While the two CTG models chosen for evaluation within this application are not exhaustive of the possible models within the desired size range, they are representative of such models and capture the range of expected duct firing requirements."

Section 2.1.1 also states:

"As noted, there are multiple CTG equipment suppliers available for this project. In addition to meeting power generation needs projected by CECo's integrated resource planning, the new station and equipment must be capable of "black starting" and providing power to the Karn Station for system restoration. This will be accommodated by first starting a black start/peaking CTG and then one of the four CTG/HRSG trains. It is imperative that the generating equipment purchased for this project has proven reliability with minimal outages for maintenance. Basic performance specifications for two specific CTG models, designated as Technologies A and B, are included in this application. Each of Technologies A and B represent common, comparable CTGs within F-Class turbine technology (a CTG's "class" is an overall measure of a CTGs volumetric air flow, compressor pressure ratio and firing temperature; the term is not vendor specific). Please note that Tables 2-1A and 2-1B identify the basic emissions and performance specifications for both Technologies, and there are relatively minor variations in raw emission rates between them. There is no single equipment option that has the lowest raw emissions profile across the board for all pollutants. We address this issue in greater detail in the BACT section (Section 5) of this permit application."

Comment

8. The draft permit proposes a Nitrogen Oxide (NOx) limit for the combined cycle combustion turbines for both technologies A or B at 3.0 ppmdv at 15% oxygen. A review of EPA's RACT/BACT/LAER Clearinghouse for PSD permits with combined cycle generation units have NOx BACT limits at 2.0 ppmdv. While we support the determination for the application of dry low NOx burners and selective catalytic reduction as BACT, the Fact Sheet does not provide MDEQ's basis for its determination of why a 2.0 ppmdv BACT limit is infeasible. The applicant may have reached such a conclusion in its application for this project, however, the permit record does not demonstrate that MDEQ agrees that the BACT limit should be 3.0 ppmdv versus 2.0 ppmdv.

AQD Response

The original application and modeling analysis was based on an emission rate for NOx of 4 ppm dry at 15% oxygen, except during startup and shutdown, 24-hour rolling average as determined each hour the turbine operates. After further evaluation and discussions with AQD, CECo reduced their proposed value to 3 ppm.

The NOx emission limit is based on what can be demonstrated on a continuous basis using a continuous emissions monitoring system (CEMS). Actual emissions may be lower. Performance Specification (PS) 2 takes into account the Maximum Potential Concentration as one factor in determining the high span value of the NOx monitor. Low NOx emission measurements are considered to be values less than 15 ppm. A RATA for a low NOx source must be accurate within a relative error range of 20%. Drift of the NOx CEMS must be less than 2.5% of the full span per day. In absolute terms, a variance of 0.5 ppm is a reasonable expected accuracy level. Although control equipment manufacturers have been known to guarantee an emission level of 2 ppm for NOx control from a gas turbine, as a practical matter PS2 requires relative accuracy measurement of NOx emissions to be less than 10 per cent of the emission limit. The reasonable expected accuracy level of 0.5 ppm exceeds the 10 per cent standard at an emission limit below 5 ppm. Despite this, CECo proposed a limit of 3 ppm. That means they must meet an accuracy level of 0.3 ppm to meet the 10% standard in PS2. A limit of 2 ppm may look good on paper in the RBLC database, but measurement accuracy uncertainties leave the validity of such a limit open to question.

Other variables affecting the reliability and accuracy of the NOx CEMs data include the reliability of calibration gases, variations in the CEMS components, variations within the emission control catalyst bed, and process variability. At low emission rates, small variations become magnified and false exceedances can be reported. One study indicates a RATA failure rate of 20 per cent or higher where process equipment is subject to very low emission limits for NOx.

AQD therefore set BACT as a NOx limit of 3 ppm dry at 15% oxygen, except during startup and shutdown, 24-hour rolling average as determined each hour the turbine operates. The 3 ppm value is at the lower level of NOx emissions verifiable using a CEMS taking into account an expected variance of ±0.5 ppm. The permit limit is in absolute terms, that is, 3 ppm without the ±0.5 ppm.

One additional consideration not evaluated during the permit review is the likelihood of excess emissions of ammonia which are likely to occur if CECo would attempt to meet a limit of 2 ppmdv. Clearly the reduction in NOx emissions from 3 ppmdv to 2 ppmdv must occur in the add-on control equipment, that is, the selective catalytic reduction emission control. The use of more ammonia than the theoretical minimum would be a certainty. Excess ammonia emissions, also called "ammonia slip" would occur and need to be evaluated.

Comment

9. The NOx emission limits for the control technique guidelines include a limit of 760 lbs/hr applied as a 1-hour average on a per block basis. It is unclear what the basis of this is because it doesn't appear to be linked to any modeling scenario. If the limit is related to EPA's intermittent source policy (EPA NO_2 Clarification Memo dated March 1, 2011), applying the intermittent policy to the startup/shutdown operations in this case is questionable given that startup/shutdown scenarios are estimated to occur over 900 hours during the year. Additionally, the startup modeling scenarios appear to apply the worst case startup/shutdown event emissions throughout the five modeled years so it's unclear the origin and purpose of the 760 lbs/hr NOx limits. MDEQ should explain what the basis of this emission limit is within its Fact Sheet for the permit record.

AQD Response

To ensure that the proposed TGS will not result in a violation of ambient air quality standards, air quality modeling was conducted for both baseload operations and startup/shutdown (SU/SD) scenarios. A summary of the modeling results was listed on pages 5 – 7 of the Fact Sheet. All modeling was conducted separately for Technologies A and B, and the modeled CTG/HRSG SU/SD emission rates consisted of the highest average hourly emission rates across the following types of discrete SU/SD events: cold startup, warm startup, hot startup and shutdown.

The SU/SD BACT limits for the CTG/HRSGs were based upon 12-month rolling total mass emission limits. However, the AQD also felt that short term NO_x and CO SU/SD emission limits were necessary to ensure compliance with the National Ambient Air Quality Standards (NAAQS). As such, the AQD requested that CECo propose short term mass emission limits protective of the NAAQS. As part of these discussions, the AQD suggested that the expected form of the NO_x emission limit was a 1-hour average mass emission limit.

Appendix 9 of the Permit to Install Application Support Document contains Consumers Energy's proposed short term mass emission limits for SU/SD. As explained within Appendix 9, the modeled startup and shutdown emission rates represent the highest average emission rates across the various event types. For example, the highest NO_x emission rate for Technology A is associated with hot startups (i.e., 464 lbs/block-event / event/2.62 hrs = 177.3 lbs/block-hr or 88.7 lbs/unit-hr based upon two units per block). The preceding mass emission rates were modeled as occurring continuously for purposes of conducting the SU/SD modeling analysis even though SU/SD emissions are intermittent in nature.

For purposes of arriving at a 1-hour mass emission limit, the modeled SU/SD emission rates cannot be used directly, as they represent average hourly emission rates across event durations ranging from approximately 2.6 to 3.9 hours, and emissions during these SU/SD conditions are highly variable.

To help determine an achievable 1-hour average NO_x mass emission rate during startup and shutdown, CECo worked with the Technology A and B vendors in an attempt to define the maximum expected instantaneous mass emission rates during SU/SD. As noted in Appendix 9, the vendor estimated NO_x mass emission rates for SU/SD were up to 400 lbs/hr per unit.

Rather than redo all of the SU/SD modeling analyses, it was decided that a layer of conservatism within the analyses should be removed. Namely, due to the intermittent nature of SU/SD and the EPA's NO_2 Clarification Memo dated March 1, 2011, CECo investigated the maximum allowable SU/SD emission rate which would result in an annual average emission rate equal to or lower than the modeled SU/SD mass emission rates.

The EPA guidance has an entire sub-section devoted to the modeling of intermittent emissions relative to the 1-hour NO_2 NAAQS (see section titled "Treatment of Intermittent Emissions"). The EPA guidance provides two basic approaches to addressing intermittent emissions within a 1-hour NO_2 modeling analysis – either excluding such emissions from the 1-hour NO_2 NAAQS modeling analysis or utilizing an annual average hourly emission rate in lieu of the maximum hourly emission rate. Pursuant to this guidance, CECo proposed to use annual average NO_x emission rates to determine compliance with the 1-hour NO_2 standard. Based on the proposed maximum short term startup emissions rate of 760 lbs/hr/block (note that the NO_x 3 ppm at 15 O_2 limits effectively limit the non-SU/SD NO_x emission rates to 29.28 lbs/hr for each Tech A CTG/HRSG and 29.25 lbs/hr for each Tech B CTG/HTRSG) and the maximum SU/SD hours of 932.5 hours per year (consistent with the annual NO_x mass emission limit for SU/SD) and the remaining 7,827.5 hours of the year at baseload operations, the annual average NO_2 emission rate were calculated by the following:

$$\text{Tech A NO}_\text{x}\text{ Rate}_{\text{Ann Avg}} = \frac{\left(\frac{760\text{ lbs}}{\text{Block hr}_{\text{SUSD}}} \text{ x } \frac{932.5\text{ hrs}_{\text{SUSD}}}{\text{Year}}\right) + \left(\frac{28.29\text{ lbs}}{\text{Unit hr}_{\text{baseload}}} \text{ x } \frac{2\text{ Units}}{\text{Block}} \text{ x } \frac{7{,}827.5\text{ hrs}_{\text{baseload}}}{\text{Year}}\right)}{\frac{8{,}760\text{ hrs}}{\text{year}}}$$

$$= \frac{131.5\text{ lbs}}{\text{Block hr}}$$

The SUSD dispersion modeling submitted with the permit application for Technology A was run for 88.7 lbs/hr/CTG or 177.4 lbs/hr/block, which is substantially higher than the annual average emission rate resulting from the emission limitations contained in the draft permit. Therefore, the annual average NO_x emission rate inclusive of SU/SD and normal operation was less than the modeled emission rate and no further modeling was necessary. Similarly, the Technology B annual average emission rate were calculated by the following:

$$\text{Tech B NO}_\text{x}\ \text{Rate}_{\text{Ann Avg}}$$
$$= \frac{\left(\frac{760\ \text{lbs}}{\text{Block hr}_{\text{SUSD}}} \text{ x } \frac{932.5\ \text{hrs}_{\text{SUSD}}}{\text{Year}}\right) + \left(\frac{29.25\ \text{lbs}}{\text{Unit hr}_{\text{baseload}}} \text{ x } \frac{2\ \text{Units}}{\text{Block}} \text{ x } \frac{7{,}827.5\ \text{hrs}_{\text{baseload}}}{\text{Year}}\right)}{\frac{8{,}760\ \text{hrs}}{\text{year}}}$$
$$= \frac{133.2\ \text{lbs}}{\text{Block hr}}$$

The SU/SD dispersion modeling submitted with the permit application for Technology B was run for 67.07 lbs/hr/CTG or 134.14 lbs/hr/block, which is higher than the annual average emission rate resulting from the emission limitations contained in the draft permit to install. Therefore, the annual average NO_x emission rate inclusive of SU/SD and normal operation was less than the modeled emission rate and no further modeling was necessary.

Relative to whether SU/SD can be considered intermittent for the proposed TGS in light of such scenarios occurring up to 932.5 hrs/yr per block, the EPA's March 1, 2011 memorandum notes the following:

"Similarly, the frequency of startup/shutdown emission scenarios may vary significantly depending on the type of facility. For example, a large baseload power plant may experience startup/shutdown events on a relatively infrequent basis whereas as a peaking unit may go through much more frequent startup/shutdown cycles. It may be appropriate to apply this guidance in the former case, but not the latter."

"Another approach that may be considered in cases where there is more uncertainty regarding the applicability of this guidance would be to model impacts from intermittent emissions based on an average hourly rate, rather than the maximum hourly emission. For example, if a proposed permit includes a limit of 500 hours/year or less for an emergency generator, a modeling analysis could be based on assuming continuous operation at the average hourly rate, i.e., the maximum hourly rate times 500/8760. This approach would account for potential worst-case meteorological conditions associated with emergency generator emissions by assuming continuous operation, while use of the average hourly emission represents a simple approach to account for the probability of the emergency generator actually operating for a given hour. Also note that the contribution of intermittent emissions to annual impacts should continue to be addressed as in the past to demonstrate compliance with the annual NO2 standard."

TGS is expected to operate in an intermediate to baseload manner, not as a peaking facility. Thus, there is nothing within the EPA guidance which would suggest that the SU/SD emissions are not intermittent in nature (i.e., there is no bright line test for a number of hours which would be considered intermittent, and SU/SD will certainly not be as frequent as that which would be observed at a peaking facility).

Comment

10. The modeling applied the intermittent policy to fire pumps for the 24-hour Particulate Matter less than 2.5 microns in size ($PM_{2.5}$). The EPA's 2011 policy memo recommends limiting emissions scenarios to "those emissions that are continuous enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations." This recommendation is generally applicable for 1-hr NO_2 and SO_2 attainment demonstrations. However, it isn't generally applicable to longer averaged time periods such as for the 24-hour $PM_{2.5}$. MDEQ should provide justification for the use of the intermittent policy for a 24-hour standard as part of the permit record.

AQD Response

In response to US EPA Region 5 concerns regarding the use of an annual average $PM_{2.5}$ emission rate relative to the 24-hour ambient standards, CECo conducted additional $PM_{2.5}$ modeling as further discussed below.

The emergency fire pump engine is not intended for continuous duty over a daily or annual basis. Relative to the GHG BACT analysis, the emergency fire pump engine is already limited to no more than 100 hrs/yr of operation. With the exception of emergency conditions, operation of the emergency fire pump engine will generally be associated with required National Fire Protection Association (NFPA) readiness testing and maintenance activities. As such, CECo agreed to an additional operating restriction that daily operation of the emergency fire pump engine be limited to no more than 6 hours per day except during emergency conditions (in which case the remainder of the TGS will not be in service).

CECo also reviewed the draft PM_{10}/$PM_{2.5}$ emissions limits. The basis of these emission limits were emission factors contained in US EPA's *AP-42 Compilation of Air Pollutant Emissions Factors* Document, Chapter 3. After further review of the draft PM_{10}/$PM_{2.5}$ emission limits and discussions with equipment vendors, CECo agreed to lower the PM_{10}/$PM_{2.5}$ emission limit to 0.14 lbs/hr.

The combination of the proposed daily operating restriction (6 hrs/day) and revised short term PM_{10}/$PM_{2.5}$ mass emission limit (0.14 lb/hr) results in a daily average emission rate of 0.035 lb/hr. This revised modeled emission rate has been evaluated by the AQD and been found to result in compliance with the applicable PSD Class II Increments and NAAQS.

B. Sierra Club Comments

Comment

S1. MDEQ Must Consider Alternative Generation Technologies Such As Renewable Energy Generation

AQD Response

AQD does not agree with the statement that it must engage in an evaluation of need. AQD does not have the statutory authority to deny an application for a permit to install solely because the agency does not believe that the proposed project is needed. Furthermore, the comment urges AQD to consider a variety of alternative projects, which the commenter asserts that, if adopted, would make the proposed project unnecessary. The comment lists a variety of technologies such as, smaller boilers; energy efficiency measures; wind, solar, geothermal and other generation technologies; and demand side management without providing any specific information regarding these alternatives. The comment does not provide information from which AQD could conclude that the project as proposed will not comply with all existing state and federal air quality regulations.

It is also noted that electric generation planning in Michigan is based on a Certificate of Necessity process that requires approval through the Michigan Public Service Commission. That process is intended to more directly address the concerns expressed in this comment.

Comment

S2. MDEQ Must Establish the GHG BACT Limit Based on the Most-Efficient, Lowest Polluting Turbine Design Technology.

AQD Response

CECo determined that new generating capacity was needed beginning as early as 2016. They also determined that the most cost effective and energy efficient methodology was based on the actual site conditions and confirmed that two 2x1 configurations involving advanced F-class combustion turbines best fit their needs from an operating flexibility and timing perspective. AQD agreed with the permit application analysis and selection of the highly efficient F-class CTGs. AQD also agreed to Public Notice the two different but most advanced F-class CTGs to enable commercial selection later so as to minimize overall project capital cost. Technology “A” and “B” have virtually the same thermal efficiency and heat rate at international organization for standardization (ISO) conditions; differences in CO_2e/MWh is related to the fact that CTGs are of slightly different size and require slightly different HRSG duct burning contributions to achieve summer generation need (summer conditions define project capacity need).

The comments suggests that a Siemens SCC6-8000H turbine design would yield a lower net CO_2e/MWh value and BACT emission rate and included a table defining "candidate BACT technologies". Both Technologies "A" and "B" evaluated by CECo are more efficient evolutions of several CTG models listed in the Sierra Club table. In addition, although the Siemens SCC6-8000H turbine design has not yet been commercially operated in North America, it was considered in generation planning activities in multiple different combined cycle configurations but was found to not be economical or well aligned with CECo's 1,400 MW need. Two 1x1 and two 2x1 SCC6-8000H blocks yield less than 800 MW and over 1,600 MW respectively, requiring either supplemental generating equipment (less efficient/higher emissions) or continuous part-load 2x1 operation (less efficient/higher emissions). The information included in the comment consists of general vendor specifications. The vendor specifications cited in the comment have not been incorporated into actual GHG BACT emission limitation(s) that have been demonstrated in practice. BACT is an emissions limitation based on the maximum degree of control that can be achieved on a case-by-case decision that considers energy, environmental, and economic impact. The comment does not provide sufficient information for AQD to alter the case-specific GHG BACT determination contained in the Fact Sheet and permit record.

Comment

S3. MDEQ's Adjustments to Manufacturer Ratings Are Not Supported

AQD Response
The permit limits emissions at rates that are enforceable and achievable over the expected range of operating conditions to be encountered during the operating life of the equipment. It is standard practice in permitting to provide a margin of compliance over the ideal operating conditions when establishing emission limits. A 10% margin of compliance is reasonable and not excessive and is intended to establish an appropriate emission limit for the operating life of the equipment.

Comment

S4. MDEQ Must Consider Alternatives to Duct Firing

MDEQ Must Consider Alternatives to Duct Firing
The Proposed Facility plans to incorporate natural gas-fired duct burners in the CT/HRSG trains. Duct burners are very inefficient compared to overall combined-cycle turbine operations. Duct burners therefore result in additional emissions. A top-down BACT analysis should look at cleaner production processes for achieving the additional on-peak energy that the duct burners would provide. Alternatives to duct burners could include battery storage, solar hybrid configuration (or a combination battery and solar hybrid), a small combustion turbine, or using the auxiliary boiler for supplemental steam.

AQD Response

The comment cites the use of a solar thermal component in the Palmdale Hybrid Power Project and Victorville 2 hybrid facility as an alternative control technology to be considered in the BACT analysis for GHG. The primary purpose of the project is to provide up to a nominal 1,400 MWe of baseload electricity for distribution throughout CECo's service territory, along with appropriate auxiliary and peaking equipment to match demand needs. Renewable energy facilities require significantly more land to construct, and need to be located in areas with very specific characteristics. Wind and solar facilities have power generation profiles that cannot match demand; conventional power plants are needed in order to follow demand.

Furthermore, EPA in their October, 2011, Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Palmdale Hybrid Power Project explicitly stated that requiring the use of solar energy as BACT at a combustion turbine electric generating unit would redefine the source:

"The applicant is proposing to use 251 acres of a 331-acre lot for solar generation. An-all solar facility would not be feasible because of the space constraints of the 331-acre lot and because solar energy is not available at all times to meet baseload demands. Given the scope of the Project, it is not necessary for the applicant to determine an optimal ratio of solar to natural gas.

Finally, we note that the incorporation of the solar power generation into the BACT analysis for this facility does not imply that other sources must necessarily consider alternative scenarios involving renewable energy generation in their BACT analyses. In this particular case, the solar component was a part of the applicant's Project as proposed in its PSD permit application. Therefore, requiring the applicant to utilize, and thus construct, the solar component as a requirement of BACT did not fundamentally redefine the source. EPA has stated that an applicant need not consider control options that would fundamentally redefine the source. However, it is expected that each applicant consider all possible methods to reduce GHG emissions from the source that are within the scope of the proposed project."

Because the proposed facility consists of natural gas combustion electric generating units intended to provide intermediate to baseload power, AQD has concluded that the addition of a renewable energy component would fundamentally redefine the source and, therefore, should not be included in the BACT analysis.

The comment also suggested consideration of several other technologies in lieu of duct burning, in order to increase the project's efficiency: battery storage, a small combustion turbine, or using the auxiliary boiler for supplemental steam. While the comment itself does not provide any information from which AQD could reasonably conclude that use of these technologies would increase project efficiency, AQD researched the suggested alternatives. No renewable energy source including battery or solar hybrid configuration is large enough or has suitable scalability to meet the same capacity as duct burning. The facility is configured to have two peaking CTGs, which may be used to meet said peak demand instead of the HRSG duct burners if the demand is less than 30 MW (capacity of both peaking turbines). Other sources such as the auxiliary boiler do not have sufficient size or efficiency.

From cost, technology, efficiency, reliability and emissions perspectives, HRSG duct burning is the best choice to meet CECo's dispatchable power needs. Duct firing is typically employed in a combined cycle configuration to meet peak electrical demands from the generating station, when called upon by the regulating/balancing authority (e.g., MISO). In the case of the TGS conceptual design, duct firing equipment was sized to overcome weather-based degradation and to achieve summer generating capacity per 2x1 block of nominally 700 MW. This duct firing capacity can be called upon at any time once base load conditions have been achieved in a 2x1 block.

Comment

S5. MDEQ Improperly Rejected CCS in Step 4 Without a Site Specific Analysis.

AQD Response

The Michigan Basin geologic formation has been cited by the U.S. Geologic Service as having a reasonably large carbon dioxide storage capacity, which is supportive of future CCS opportunities. Additional scientific work is required to define technical requirements for liquid carbon dioxide injection and management in this Basin. In addition, the MDEQ is not aware of any project where the cost effectiveness to remove carbon dioxide from CTG/HRSG exhaust streams, compress such streams into a pressurized liquid, pipe such to a discharge well for deposition, and safely manage and store such a pressurized liquid in a geological formation have been shown to be economical. Further, the legalities and long-term liabilities associated with CCS in Michigan have not been defined, and significant uncertainty remains as to whether CCS will be allowed in the future. As a result, a site-specific analysis cannot be accurately completed without having a known CCS host and life cycle costs quantified. Consequently, a comparative BACT analysis was conducted to determine the relative economic viability of CCS for this project.

During Step 4 of the Top Down BACT analysis for CO_2e, AQD compared the anticipated economic impacts of CCS to economic impacts that had been shown to be cost-effective for other pollutants. This was done because AQD did not have cost data for controlling GHG from a similar project using CCS. Given the difference in applicability thresholds between greenhouse gases and other regulated NSR pollutants, AQD used a similar ratio to provide a reasonable basis for comparing actual project control costs between pollutants. The comment does not provide enough information for AQD to determine that this comparison methodology was not reasonable. Furthermore, the US EPA's PSD and Title V permitting Guidance for Greenhouse Gases (EPA-457-B-11-001, March 2011) notes the following on Page 43 in regards to assessing the affordability of GHG controls on a \$/ton CO_2e removed basis:

"As in the past for criteria pollutant BACT determinations, the final decision regarding the reasonableness of calculated cost effectiveness values will be made by the permitting authority. This decision is typically made by considering previous regulatory and permitting decisions for similar sources. As noted above, to justify elimination of a control option on economic grounds, the permit applicant should demonstrate that the costs of pollutant removal for the particular option are disproportionately high. However, given that there is little history of BACT analyses for GHG at this time, there is not a wealth of GHG cost effectiveness data from prior permitting actions for a permitting authority to review and rely upon when determining what cost level is considered acceptable for GHG BACT. As the permitting of sources of GHG progresses and more experience is gained, additional data to determine what is cost effective in the context of individual permitting actions will become known and should be included in the RBLC. We note, however, that when looking at pollutants historically regulated under the PSD Program, such as criteria pollutants, the cost effectiveness of a control device is based on a significantly lower volume of emissions than the amount of emissions that are emitted by most sources of GHGs. For example, a new boiler that is subject to the NSPS and emits 250 TPY of NOX will emit well above 100,000 TPY of CO2e. As a result, even taking account of the current limited data and consequent uncertainty concerning the costs of GHG BACT, it is reasonable to anticipate that the cost effectiveness numbers (in $/ton of CO2e) for the control of GHGs will be significantly lower than those of the cost effectiveness values for controls of criteria pollutants that have evolved over time."

At the time the agency proposed the BACT determination in the draft permit conditions and Fact Sheet, AQD was aware of the Southern Company's Kemper IGCC Plant ("Kemper IGCC") and the Summit Texas Clean Energy Project ("Summit TCEP") referenced in the comment. Both Kemper IGCC and Summit TCEP are CCS demonstration projects and the use of CCS was not the result of a GHG BACT determination. These CCS demonstration projects differ from the proposed project because each project will utilize coal as a feedstock and will create a synthetic gas which will be fired in combined-cycle turbines. The gasification technology yields synthetic gases containing primarily hydrogen and CO_2, with CO_2 concentrations of approximately 30-32% by volume[1]. In contrast, the CO_2 concentrations present in the exhaust gases from natural gas-fired combustion turbines are approximately 4%[2]. The dilute CO_2 concentration for natural gas-fired combined cycle turbines relative to IGCC synthetic gas results in the CO_2 removal process being substantially more difficult and expensive. Furthermore, each CCS demonstration project was the recipient of Department of Energy (DOE) grant funding. Specifically, the Kemper IGCC project received a 270 million dollar grant from the DOE, while the Summit TECP received a 450 million dollar award from the DOE[3]. The fact that each CCS demonstration project required federal grant funding demonstrates that the CCS costs for Kemper IGCC and Summit TCEP do not represent economically feasible costs from a similar project that would be appropriate for use in a BACT analysis.

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[1] Coupling CO_2 Capture and Storage with Coal Gasification: Defining "Sequestration-Ready" IGCC, May, 2005, available at http://www.netl.doe.gov/publications/proceedings/05/carbon-seq/Tech%20Session%20Paper%20144.pdf

[2] Carbon Capture Approaches for Natural Gas Combined Cycle Systems, December 20, 2010. available at http://www.netl.doe.gov/energy-analyses/pubs/C_Capture_NGCC_20101220.pdf

[3] Refer to the project specific fact sheets as available at MIT's Carbon Capture & Sequestration Technologies website at http://sequestration.mit.edu/tools/projects/index_capture.html