Title V Permit Renewal

DEC Request for Additional Information

Cricket Valley Energy Center LLC
2241 Route 22
Dover, Dutchess County, NY 12522
NYSDEC Permit ID No. 3-1326-00275/00009

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Submitted to:
New York State Department of Environmental Conservation
Division of Air Resources, Region 3
21 South Putt Corners Road
New Paltz, NY 12561-4659

Prepared by:
Berkshire Environmental Consultants, Inc.
1450 East Street, Suite 6-H
Pittsfield, MA 01201

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1 Introduction

On July 23, 2020, Cricket Valley Energy Center, LLC (CVEC) submitted an application to the New York State Department of Environmental Conservation (NYSDEC or "the Department") for renewal of the Title V Operating Permit (Permit ID 3-1326-00275/00009) for the CVEC natural-gas fired, combined-cycle, electric generating facility in Dover, NY. In accordance with Title 6, Subpart 201-6 of the New York Codes, Rules, and Regulations (NYCRR), the renewal application was submitted at least 180 days, but not more than 18 months, prior to expiration date (February 2, 2021) of the current permit. The permit application did not include any new or modified sources or increases in greenhouse (GHG) gas emissions from existing sources.

On May 20, 2022, NYSDEC sent CVEC a Request for Additional Information (RFAI) to aid in the Department's determination of whether the permit renewal is consistent with the statewide GHG emission limits established by the NY Climate Leadership and Community Protection ACT (CLCPA) in Article 75 of Environmental Conservation Law (ECL). This document provides CVEC's response to the NYSDEC RFAI.

2 Background

2.1 Applicable CLCPA Requirements

The NY CLCPA became effective on January 1, 2020. Section 7(2) of the CLCPA directs state agencies to consider whether decisions by the agency, including permit approvals, are inconsistent or will interfere with the attainment of the statewide GHG greenhouse emissions limits in ECL Article 75. For decisions that are determined to be inconsistent with or that will interfere with the attainment of the limits, the agency must provide a detailed justification as to "why such limits/criteria may not be met" and identify required alternatives or mitigation measures. Additionally, Section 7(3) of the CLCPA requires that agencies, when considering approvals and decisions, must not disproportionately burden disadvantaged communities and must prioritize reductions of GHGs and co-pollutants in these communities.

The ECL Article 75 statewide GHG emission limits, as stated in Title 6, Part 496 of the New York Codes, Rules, and Regulations (6 NYCRR 496), are as follows:

- 245.87 million metric tons CO_2 equivalent[1] (CO_2e) by the year 2030, and
- 61.47 million metric tons CO_2e by the year 2050.

These limits represent a 40% and 85% reduction, respectively, from estimated 1990 statewide GHG emissions. The CLCPA requires[2] that NYSDEC promulgate, by 1/1/2024, implementing regulations containing legally enforceable emissions limits, performance standards, or other measures to ensure the statewide GHG emission limits are met. These regulations must be developed after public workshops and hearings and in consultation with stakeholders and the "Climate Action Council" (CAC), "Climate Justice Working Group" (CJWG) and "Just Transition Working Group" (JTWG) established by the CLCPA and be

[1] CO_2 equivalents determined using the 20-year global warming potentials in 6 NYCRR 496.4.

[2] ECL §75-0109

based on the findings of the CAC Scoping Plan. As of the date of this submittal, the CAC Scoping Plan has not been finalized and the CLCPA implementing regulations have not been proposed by NYSDEC.

The NYSDEC has issued a draft revision to Commissioner's Policy CP-49, *Climate Change and DEC Action*, which addresses implementation of the CLCPA Section 7(2) requirement to evaluate the Department's decisions for compatibility with the GHG emission limits and consideration of the impacts to disadvantaged communities required by CLCPA Section 7(3). The NYSDEC has also issued a draft Division of Air Resources Policy DAR-21, *Climate Leadership and Community Protection Act and Air Permit Applications*, which provides "guidance for applicants and DEC staff" when preparing and reviewing CLCPA analyses submitted in support of air permit applications. As of the date of this submittal, these policies have not yet been finalized.

A separate provision of the CLCPA modifies Section 66 of the NY Public service Law (PSL) to require that the NYS Public Service Commission (PSC) establish "targets" for electrical power generation from renewable sources as follows:

- by the year 2030 at least 70% of the statewide electric generation will be generated by renewable energy systems; and
- by the year 2040 the statewide electrical demand system will be zero emissions.

2.2 NYSDEC Information Request

In the May 20, 2022 RFAI, NYSDEC asked that CVEC provide the following information to support NYSDEC's review of the CVEC Title V Operating Permit renewal application pursuant to Section 7(2) and 7(3) of the CLCPA:

- Calculations showing the facility's potential GHG emissions in CO2 equivalents, including upstream emissions and, if possible, the projected facility emissions for the years 2030 and 2050. [Sections 3.3 & 3.4]

- A discussion of how GHG emissions from the facility will be mitigated or reduced consistent with the CLCPA statewide emission limits in ECL Article 75 and the CLCPA requirement for zero-emissions from the electric generation sector by 2040. [Section 6]

- An explanation if there are no feasible ways to reduce GHG emissions. [Section 6]

- Calculations of co-pollutant emissions and a discussion of any alternatives or mitigation measures that will be used to reduce the impact of those emissions if the project is in or potentially impacts a Draft Disadvantaged Community identified by the CJWG. [Section 7]

In subsequent correspondence and conversations with CVEC NYSDEC indicated that the draft DAR-21 should be used as guidance for the response to the RFAI.

The RFAI requested information conflicts with the guidance in draft DAR-21 and the CLCPA requirements in that the draft DAR-21 requires an applicant to identify potential alternatives or mitigation measures *only if* the project will result in an increase in potential GHG emissions or if DEC determines that it is inconsistent with the attainment of the statewide GHG emission limits. Likewise, Section 7(2) of the CLCPA requires that DEC review its decisions for consistency with the statewide GHG emission limits in ECL Article 75 (and identify alternatives or mitigation measures if a decision is inconsistent), but it *does not* require

DEC to review actions for consistency with the renewable energy targets in PSL Section 66-p. Nor does it require applicants to provide information on how GHG emissions will be reduced or mitigated to meet these targets.

Likewise, as discussed in 2.1 above, the CAC Scoping Plan has not been finalized and the CLCPA implementing regulations have not been proposed by NYSDEC; it is therefore too early to be asking for CLCPA related information.

Nonetheless, CVEC has tried to provide as much of the requested information as possible in the interest of moving its application forward.

2.3 Facility Description

The CVEC facility consists of three General Electric (GE), Model 7FA.05, combined-cycle combustion turbine generator (CTG) units that commenced commercial operations in October and November 2019, and February 2020, respectively. It is one of the most efficient thermal generation sources in the state of New York. As a result, it often displaces older less efficient generation resources which reduces the state's overall emissions profile.

Each combustion turbine exhausts via a heat recovery steam generator (HRSG) equipped with duct burners (DB) for supplemental firing and a separate stack. A 60 MMBTU/hr auxiliary boiler, used to assist with plant startup and to keep plant components warm during standby periods, exhausts via the CTG #1 stack.

The facility also includes a 1,500 kW emergency diesel generator and a 260-hp diesel powered emergency fire pump. In lieu of a cooling tower and non-contact cooling water system, the CVEC facility uses a dry cooling system and an air-cooled condenser which has no air emissions.

The CTGs, DBs, and auxiliary boiler fire pipeline natural gas. The auxiliary boiler is limited to 4,500 hours of operations per year, or less, which equates to a maximum of 270 million cubic feet of natural gas per year. The two emergency diesel engines use ultra-low sulfur diesel (ULSD) fuel with a sulfur content of less than or equal to 15 ppm by weight and are limited to 500 hours of operations per year.

The GE 7FA.05 combustion turbines use a dry low NOx (DLN) combustion system to reduce NOx emissions. The duct burners and auxiliary boiler are also equipped with low NOx burners. A selective catalytic reduction (SCR) system and oxidation catalyst in each HRSG further reduce NOx, CO, and VOC emissions from the CTGs and DBs.

The combined-cycle units are subject to 6 NYCRR 251.3(a), which limits CO_2 emissions from new electric generating facilities. The current Title V Permit also contains "Best Available Control Technology" (BACT) limits on GHG emissions, in CO_2e, for the auxiliary boiler, the two diesel engines, and the facility as a whole.

3 Calculated Greenhouse Gas Emissions

The NYSDEC RFAI requested that CVEC "calculate the project's potential to emit GHG," including any upstream emissions, and "include calculations showing the project's projected GHG and CO_2e emissions in the years 2030 and 2050, if possible”. The draft DAR-21 policy states[3] that calculations of actual direct GHG emissions from the project should also be included with the analysis.

The draft DAR-21 policy defines the “project scope” as “any new or modified emission sources that have the potential to emit GHG” and excludes “existing equipment whose operations are not being changed unless deemed necessary to assess CLCPA consistency. Although the CVEC Title V Renewal application does not include any new or modified emissions sources, the actual and potential GHG emissions from existing sources at the facility were calculated and included as described in the following paragraphs.

3.1 Direct Emissions Calculations

For the purpose of this analysis, direct GHG emissions were calculated based on potential and actual fuel consumption in the three combined-cycle units (GTGs and DBs), the auxiliary boiler and the two emergency diesel engines. Emissions from trivial and mobile sources at the facility were not included. Greenhouse gas emissions from the combustion sources at the facility include carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O).

For consistency with other applicable GHG reporting requirements, emission factors from the following sources were used in the calculations. As per the RFAI and the draft DAR-21, the 20-year global warming potentials (GWP20) from 6 NYCRR 496.5 were used to calculate GHG emissions as CO_2 equivalents (CO_2e).

Table 1: Sources of GHG Emission Factors

<table>
<tr><th></th><th>CO2</th><th>CH4 / N2O</th><th>GWP20</th></tr>
<tr><td>GTGs & DB</td><td>40 CFR 75, App. G, Eqn. G-4</td><td rowspan="3">40 CFR 98, Table C-2</td><td rowspan="3">6 NYCRR 496.5</td></tr>
<tr><td>Auxiliary Boiler</td><td rowspan="2">40 CFR 98, Table C-1</td></tr>
<tr><td>Emergency Diesel Engines</td></tr>
</table>

3.2 Upstream Emissions Calculations

The NYSDEC RFAI requests that CVEC include in its potential emissions calculations “upstream” GHG emissions associated with the generation of electricity imported into the State, or the extraction, transmission, and use of fossil fuels imported into the State. The maximum potential GHG emissions will occur when the combined-cycle units are continuously operating and generating electricity, in which case no imported electricity will be used at the facility. The calculated upstream GHG emissions, therefore, consist solely of emissions due to natural gas and ULSD[4] imported into the State for use as fuel for the facility combustion units.

The RFAI instructs CVEC to calculate upstream GHG emissions using emission factors from *Appendix A, Emission Factors for Use by State Agencies and Applicants*, of the *NYSDEC 2021 Statewide GHG Emissions Report* unless a different value is supported by an appropriate justification. These emission factors are based on data and methodology in a report[5] prepared for NYSDEC and the New York State Energy Research & Development Authority (NYSERDA) which, for natural gas, uses the National Energy

[3] Section V.C.1.
[4] The calculations conservatively assume that all the ULSD used at the facility is imported into the state.
[5] *Technical Documentation: Estimating Energy Sector Greenhouse Gas Emissions Under New York State’s Climate Leadership and Community Protection Act*, Eastern Research Group, Inc., December 20, 2021

Technology Laboratory (NETL) Natural Gas model (NETL, 2019) along with available empirical data to determine upstream fuel cycle emissions for New York State. As noted in the *NYSDEC 2021 Statewide GHG Emissions Report*, these emission factors are "a work in progress, subject to future stakeholder comment, and will be subject to a continual improvement process as additional information becomes available".

CVEC does not possess information on GHG emissions from the extraction, production, or transmission of fuels used at the facility and cannot, therefore, propose an alternate emission factor or confirm that the emission factors in the Statewide GHG Emissions Report are a reasonable approximation of upstream GHG emissions from fuels delivered to the CVEC site. The emission factors from the 2021 Statewide GHG Emissions Report were used to calculate potential GHG emissions, but CVEC cannot verify that the resulting values correctly reflect upstream emissions attributable to the facility.

3.3 Potential GHG Emissions

The potential GHG emissions calculations for the CVEC facility are included in Appendix A and summarized in Table 2 below. Potential direct GHG emissions from the CTGs and DBs were calculated using 8760 hours of operation and the design heat input rate at ISO conditions (e.g., 59 deg. F ambient temperature). Potential GHG emissions from the auxiliary boiler and the diesel engines were calculated using the design heat input / fuel consumption rate and the maximum annual operating hours allowed by the Title V Permit for each emission source (4,500 hours/year for the auxiliary boiler and 500 hours/year for each emergency engine).

The CVEC facility Title V Permit contains an annual limit of 3,593,609 tons per year total GHG emissions (CO2e) from all combustion sources at the facility. This limit is more restrictive than the sum of the calculated potential emissions for the individual sources and, therefore, represents the maximum potential GHG emissions for the facility. The facility-wide GHG limit in the Permit is based on 100-year global warming potentials. The equivalent facility-wide GHG Potential to Emit (PTE), using 20-year GWPs, is estimated as 3,597,312 tons/year.

Potential upstream GHG emissions attributable to CVEC facility operations were calculated using emission factors from Appendix A of the *NYSDEC 2021 Statewide GHG Emissions Report* and the maximum potential natural gas and ULSD that could be used annually at the facility. The maximum potential annual fuel use was determined by summing the maximum amount of fuel that could be used in each emission unit without exceeding an annual operating hour or GHG emissions limit in the Title V Permit. These calculations are detailed in Appendix A.

As discussed above, CVEC cannot confirm whether the emission factors in the *Statewide GHG Emissions Report* are a reasonable approximation of actual upstream emissions for fuels delivered to the facility. Consequently, the facility cannot verify the results of the upstream GHG emissions calculations.

Table 2: Maximum Potential GHG Emissions (tons/year)

Potential Direct GHG Emissions from Combustion Sources (tons/year)	Maximum Annual GHG Emissions				Permit Limits
	CO_2	CH_4	N_2O	CO_2e, GWP20	CO_2e, GWP100
Total for three CTG-DB	3,931,007	73	7	3,939,057	---
Auxiliary Boiler	15,792	0.3	0.03	15,825	---
Emergency Diesel Generator	608	0.02	0.005	611	595
Diesel Fire Pump	73.4	0.003	0.0006	74	74
Facility Total	**3,947,480**	**73**	**7**	**3,955,567**	**3,593,609***
Potential Upstream GHG Emissions from Fuels Used (tons/year)					
Natural Gas	807,673	23,769	9	2,806,713	
ULSD	136	1.1	0.002	228	
Total Upstream Potential Emissions	**807,809**	**23,770**	**9**	**2,806,942**	
Facility-wide Direct Plus Upstream Potential GHG Emissions (tons/year)					
Direct Emissions				3,597,312*	
Upstream Emissions				2,806,942	
Facility-Wide Total Potential Emissions				6,404,254	

* The facility-wide Permit limit on GHG emissions (3,593,609 tons/year, CO_2e) is based on 100-year Global Warming Potentials. The equivalent facility-wide limit using 20-year Global Warming Potentials is estimated as 3,597,312 tons/year.

3.4 Actual and Projected Actual GHG Emissions

3.4.1 Actual GHG Emissions

In addition to potential GHG emissions, the draft DAR 21 requires that each CLCPA analysis include the project's actual direct emissions (in tons/year), defined as "the highest 24-month average GHG emissions during the five years preceding the permit application". The CVEC facility commenced commercial operation in late 2019 to early 2020. Since then, the 24-month period with the highest facility GHG emissions was from October 2020 through September 2022.

Actual GHG emissions calculations for the CVEC facility are included in Appendix A and summarized in Table 3 below. Direct GHG emissions from the combustion turbines and duct burners were calculated based on quarterly reports of unit heat input and CO_2 emissions submitted to US EPA for 4th quarter 2020 through 3rd quarter 2022. Average direct GHG emissions from the auxiliary boiler and emergency diesel engines, which are a minor portion of the total facility GHG emissions, were estimated using actual fuel use and heat input reported in the facility's NYSDEC Emission Statements for calendar years 2020 and 2021. Table 3 also includes estimated upstream GHG emissions from the extraction, processing and transport of fuels used at the facility based on the actual annual fuel use and emission factors in Appendix A to the *NYSDEC 2021 Statewide GHG Emissions Report*. As noted above, CVEC cannot verify that these factors yield a reasonable estimate of the upstream emissions for fuel used at the facility.

3.4.2 Projected Actual GHG Emissions

The NYSDEC RFAI states that the CLCPA analysis should also include, if possible, calculations of the projected GHG and CO2e emissions for the years 2030 and 2050. Future operations and GHG emissions from the facility will depend, in part, on factors that are uncertain and not under CVEC's control; including the specific requirements of future NYSDEC regulations (due by 2024) to implement the state-wide CLCPA emission limits and changes in the state electric power grid and markets as they transition to meet the 2030 and 2040 renewable energy targets of the CLCPA.

In its *2021-2040 System & Resource Outlook* report[6], the New York Independent System Operator (NYISO) found that over 95 GW of new, zero GHG emissions, electric generating resources will be required to meet the CLCPA targets; including a significant amount of Dispatchable Emission-Free Resources (DEFRs) consisting of technologies that are not currently mature or commercially available. The report acknowledges that until these technologies emerge, fossil-fueled dispatchable resources will be required in some manner. The report does not, however, forecast how much individual GHG emission sources will operate. It only suggests that the remaining dispatchable fossil-fueled resources will cumulatively operate more frequently and for shorter periods of time.

It is likely that CVEC, as one of the most efficient and lowest-emitting[7] fossil-fuel electric generating facilities in the state will continue to operate in some capacity through 2030 (and beyond), to support the transition to renewable energy sources. Any forecasts of future facility operations is, however, speculative because of the uncertainties concerning future regulatory requirements, the rate of development and installation of renewable generating resources (including DEFRs), retirement of existing fossil-fueled resources, and possible electrical transmission and fuel supply constraints. For the purpose of this analysis, Table 3 indicates projected 2030 GHG emissions that are equal to current actual emissions, but this estimate will require revision (e.g., at the next Title V Permit renewal). For 2050, the projected GHG emissions in Table 3 reflect the CLCPA requirement that electric power generation in the state must be GHG emissions-free by 2040 and assume that the CVEC CT-DBs will not operate or will be converted to zero-emissions fuel (see Section 6). The remaining 2050 GHG emissions in Table 3 are consistent with current actual emissions from the auxiliary boiler and emergency diesel engines which do not generate electric power for use off site.

Table 3: CVEC Actual and Projected Actual GHG Emissions

Estimated Facility Actual GHG Emissions (tons/year, CO2e)	**Direct Emissions from Combustion**	**Upstream Emissions for Fuels Used**	**Facility Totals**
	2,058,765	1,606,480	3,665,245
Estimated Projected GHG Emissions (tons/year, CO2e)			
2030	2,058,765	1,606,480	3,665,245
2050	2,515	1,959	4,475

[6] *2021-2040 System & Resource Outlook (The Outlook): A Report from the New York Independent System Operator*, September 22, 2022.

[7] Based on quarterly data reported to US EPA's Data Clean Air Markets Division for the period from 4Q2020 – 3Q2022, the heat rate (BTU/kWh) and direct CO2 emissions (lb/MWh) from electric generation at the CVEC facility were more than 15% less than the average for all other reporting facilities in the state and more than 20% less than the average for other units that fire only pipeline natural gas.

4 Consistency with CLCPA Emission Limits

The draft revised NYSDEC Policy CP-49 states that a Department action that complies with the CLCPA implementing regulations and the CAC Scoping Plan may be considered consistent with the Emission Limits and, therefore, in compliance with Section 7(2) of the CLCPA; but DEC has not yet proposed the implementing regulations and the Scoping Plan has not been finalized. Consequently, the draft CP-49 calls for a phased-in approach when applying CLCPA Section 7(2) which, at the current stage, requires that the NYSDEC review decisions in the context of "consistency with [6 NYCRR] Part 496 Statewide GHG Emission Limit and the CLCPA Annual GHG Emissions Inventory".

Part 496 and the Annual GHG Emissions Inventory address statewide emissions and do not provide any requirements or guidance for evaluating an individual permit decision; however, both the draft revised Policy CP-49 and the draft DAR-21 state that routine permit renewals that would not lead to an increase in actual or potential GHG emissions and that do not include a significant modification would ordinarily be considered consistent with the CLCPA pending finalization of the scoping plan and future regulations. <u>The CVEC Title V Permit renewal application does not include any significant modifications to the permit and will not lead to an increase in actual or potential GHG emissions. On that basis, therefore, the Permit Renewal is consistent with the CLCPA Emission Limits per the draft DAR-21 and the draft revised CP-49.</u>

CVEC has noted that several recent Title V Permit renewals by NYSDEC contain a requirement to "comply with regulations to be promulgated by the Department" to ensure that the CLCPA statewide greenhouse gas emissions are met. This would be an appropriate requirement for the CVEC Title V renewal to ensure ongoing consistency with the CLCPA limits following the promulgation of the 2024 implementing regulations. In the meantime, the CVEC Title V Permit contains the following limits on GHG emissions that represent the "Best Available Control Technology" (BACT) and are typically not found in Permits for other facilities:

- A limit on the maximum heat rate (i.e., minimum efficiency) of the combustion turbines that ensures GHG emissions *per MWh of electricity* produced will be minimized
- A limit on the GHG emission rate from the auxiliary boiler
- Annual limits on the total GHG emissions from the emergency diesel engines
- A facility-wide annual limit on total GHG emissions

The combined-cycle units are also subject to the NYSDEC CO2 Budget Trading Program in 6 NYCRR 242 and the CO2 Performance Standards for new Major Electric Generating Facilities in 6 NYCRR 251.3(a).

The above requirements will ensure that CVEC remains one of the most efficient and lowest emitting (on a lb CO2e/MWh basis) electric generating facilities in the state at least until the next 5-year renewal when the CVEC Permit will be re-evaluated for CLCPA consistency in the context of the implementing regulations that DEC must promulgate by 1/1/2024.

5 Justification

Per the CLCPA Section 7(2) and the draft DAR-21, if NYSDEC finds that a project is inconsistent with or will interfere with the State's ability to meet the statewide emission limits, the Department must prepare a statement of justification before approving the project. While CVEC believes, as stated above, that the five-year renewal of the facility's Title V Permit is consistent with the CLCPA emission limits, it is justified in any event because of the need for efficient, dispatchable, fossil-fueled electric generating resources for grid reliability during the transition to renewable energy sources.

Recent NYISO studies have concluded that coordination of renewable energy source additions, development of dispatchable emission free technologies, continued fossil fuel plant operation, and staged plant deactivations will be essential to an orderly transition of the grid[8] over the next 18 years (until 2040) and that over 24,000 MW of conventional generation would be needed statewide[9] during this period. As a new, highly efficient, natural gas fired facility, CVEC provides a portion of that generation while producing less GHG emissions per MWh than older, less efficient facilities or facilities that fire higher emitting fuels. In addition, the NYISO 2020 Reliability Needs Report[10] identified a specific need for the Cricket Valley Energy Center stating that CVEC was one of the reasons that the deactivation of the Indian Point nuclear facility in 2020 and 2021 did not cause a reliability need.

Consequently, continued operation of the CVEC facility is required to ensure grid reliability and provide efficient, low emissions electric generation pending the technological and commercial development of dispatchable GHG emissions free resources.

6 Mitigation

The NYSDEC RFAI requests that CVEC discuss how the emissions from the facility will be mitigated or reduced consistent with the 2030 and 2050 statewide GHG emission limits and the CLCPA requirement that the energy generation sector be "zero-emissions" by 2040 or explain if there are no feasible ways to reduce GHG emissions. The following paragraphs discuss potential options that could be used, alone or in combination, to reduce or mitigate CVEC facility GHG emissions and any technical or economic barriers to their implementation.

The feasibility of these options depends on several factors that are currently uncertain and outside the control of CVEC, including future regulatory actions and policies by the NYSDEC and PSC, the development of infrastructure for alternate fuels, financial considerations (e.g., capital and operating costs and availability of financing for mitigation projects), development of new technologies, and the growth of renewable resources in the state, etc. Consequently, CVEC cannot confirm at this time which, if any, of these options will be implemented at the facility.

6.1 Alternative Fuels - Hydrogen

6.1.1 Discussion

The use of "green" hydrogen, alone or blended with natural gas, as an alternative fuel can significantly reduce[11] direct GHG emissions. To the extent that hydrogen replaces natural gas from out of state sources,

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[8] *2021-2040 System & Resource Outlook (The Outlook): A Report from the New York Independent System Operator*, September 22, 2022, pg. 8.
[9] *2021-2030 Comprehensive Reliability Plan: A Report from the New York Independent System Operator*, December 2, 2021, pg. 46.
[10] *2020 RNA Report; Reliability Needs Assessment: A Report from the New York Independent System Operator*, November 2020, pg.18.
[11] Burning pure hydrogen in the combustion turbines would eliminate CO2 and methane emissions, but there would still be some NOx (including nitrous oxide) emissions. Nitrous oxide is a GHG, but total CO2e emissions would be much lower than when firing natural gas.

it can also reduce upstream GHG emissions. The New York Power Authority (NYPA) and GE recently completed a demonstration project using 5% - 44% green hydrogen, by volume, in the GE LM6000 aeroderivative gas turbine at NYPA's 45-MW, Brentwood Power Station. The project demonstrated that CO2 mass emissions could be reduced by about 14%, using a fuel blend of 35% hydrogen by volume with natural gas while maintaining NOx and CO emissions within regulatory permit limits using existing emission controls.

The GE Model 7FA.05 combustion turbines installed at the CVEC facility can be operated, with only minor modifications, using natural gas blended with up to 15% - 20% hydrogen. Fuel blends with higher percentages of hydrogen are possible but currently require replacement of the DLN combustors with a less efficient diffusion flame-type combustion system that uses steam or water injection.

Because of the size of its F-class combustion turbine fleet (over 1,600 units worldwide) there is a strong economic incentive for GE to develop a DLN retrofit that can burn 100% hydrogen. GE is actively engaged in research and development to that end. In July 2021, GE signed a memorandum of understanding (MOU) with CVEC to advance a demonstration project[12] wherein one of the facility turbines would fire 5% percent hydrogen blended with natural gas; and in May 2022 GE was awarded $12MM in federal funding from the U.S. Department of Energy (DOE) to develop technologies for using higher percentages of hydrogen in fuel blends for gas turbines, with a specific focus on retrofits for the F-class fleet.

Currently carbon-free or "green" hydrogen, produced by electrolysis of water using renewable energy sources, comprises only about 1% of the 10 million metric tons (MMT) total annual U.S. hydrogen production[13]. Approximately 95% of the annual hydrogen production is from natural gas via the steam methane reforming (SMR) process which produces CO2 as a byproduct that must then be captured and utilized or sequestered (see Section 6.2 below). The estimated amount of hydrogen required for one of the three CVEC combined-cycle units firing 100% hydrogen is about 18,000 kg/hour (0.1 - 0.2 MMT/year).

Hydrogen is typically stored and transported as a high pressure compressed gas, in tube trailers or via pipeline, or as a cryogenic liquid[14]. Hydrogen is more flammable than natural gas and thus poses greater safety concerns in the event of leakage or venting. It is also more reactive than natural gas and can permeate and cause embrittlement of certain metals. Hydrogen can be transported in existing natural gas pipelines at concentrations of 5% - 15% by volume with only minor modifications required[15].

6.1.2 Barriers to Implementation

Hydrogen and hydrogen blended fuels are promising technologies for reducing GHG emissions that could be phased in as the needed technology and infrastructure are developed. There are, however, some significant technological and economic barriers that would need to be addressed for full-scale implementation at the CVEC facility. These include the following:

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[12] CVEC is currently attempting to secure financing for the demonstration, but it could be rendered moot by similar demonstration projects occurring elsewhere in the country.

[13] *Hydrogen Strategy: Enabling a Low-Carbon Economy*, Office of Fossil Energy, U.S. Department of Energy, July 2020.

[14] Tube trailers for hydrogen typically have a capacity of a few hundred kilograms and liquid hydrogen trailers have a capacity of 3,000 – 5,000 kilograms.

[15] *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*, National Renewable Energy Laboratory, March 2013.

- Retrofit DLN technology for firing higher percentages of hydrogen in GE 7FA.05 combustion turbines is currently under development but it is not known when it will be commercially available or what the associated costs will be.
- Current production costs for hydrogen range from < \$2/kg to \$5 - \$6/kg, depending on the method of production, with "green" hydrogen from electrolysis being the most expensive. This is equivalent to about 2 – 10 times the cost of natural gas and presents an economic barrier for implementation of hydrogen fuel. (Note that the US DOE has launched initiatives with the goal of lowering the price of clean hydrogen to \$1/kg within the next 10 years.)
- The large amounts of hydrogen required would necessitate either onsite production or transportation to the site via a dedicated pipeline or the existing natural gas pipeline. Of these options, introducing hydrogen into the existing gas pipeline could have the fewest technical barriers and could be implemented incrementally using limited quantities of hydrogen at first, but it would require a suitably located source of sufficient hydrogen production.

  Installation of a dedicated hydrogen pipeline requires a supporting hydrogen infrastructure that does not yet exist and would require substantial capital investment. In addition, permitting a new hydrogen pipeline could be difficult.

  Onsite production of hydrogen could also be implemented incrementally, using modular production units; but it would require carbon capture and sequestration (see Section 6.2) or large amounts of electrical power from renewable sources (see Section 6.3) depending on whether SMR or electrolysis of water would be used as the hydrogen production method. The current source of water to the facility is on-site wells with permitted withdrawal limits. Additional sources of water would be required if electrolysis is used for hydrogen generation.

6.2 Carbon Capture, Utilization and Sequestration (CCUS)

6.2.1 Discussion

A typical carbon capture system (CCS) uses a liquid solvent (usually amine-based) with an affinity for CO2 to absorb carbon dioxide from the combustion exhaust gases. The exhaust gas stream is cooled and directed through an absorption column where it mixes with the solvent. The CO2-rich solvent is collected at the bottom of the absorption column and pumped to a stripper column where it is heated and releases the CO2. The CO2 can then be collected and compressed for transportation and geologic storage (sequestration) or utilization in industrial processes. The CO2-lean solvent is cooled and returned to the absorption column for reuse[16].

Capture of direct CO2 emissions from fossil fuel combustion does not reduce upstream emissions associated with the production, processing, and transport of the fuel. In addition, many current CO2 sequestration projects are associated with Enhanced Oil Recovery (EOR) where captured CO2 is injected into petroleum wells to increase their productivity. In this case, the captured CO2 is used to produce more fossil fuel, which may not lead to a net decrease in GHG emissions.

[16] Eventually, depending on the chemical used, the solvent becomes degraded and must be replenished which adds to the CCS operating cost.

CCUS demonstration projects have been implemented for industrial processes (including CO2 capture for SMR production of hydrogen from natural gas), coal-fired power plants, and a few gas-fired power plants. The Inflation Reduction Act of 2022 included an expansion of the eligibility and amounts of federal tax credits for CCUS under Section 45Q of the Internal Revenue Code which may incentivize future projects.

CVEC is not aware of any current large scale retrofit of a CCUS for an existing, combined-cycle power generating facility, although U.S. DOE has awarded funding for several studies. In 2020, the Electric Power Research Institute (EPRI) was awarded funding from the U.S. DOE National Energy Technology Laboratory (NETL) to conduct a Front-End Engineering and Design (FEED) study to determine the technical and economic feasibility of a retrofit, post-combustion carbon capture unit at the California Resources Corporation's (CRC's) 550 MW, natural gas combined cycle (NGCC) Elk Hills Power Plant. EPRI submitted the final public report[17] for the study in January 2022. In February 2022, General Electric announced a $5.7MM award from US DOE for a FEED study focused on retrofittable CCUS for power generations applications, with a goal of commercial deployment by 2030, specifically for Alabama Power's James A. Barry Electric generating plant. Both the Elk Hills and James A. Barry projects involve GE F-Class combined-cycle combustion turbines.

Because of the large amount of equipment and the energy needed for heating, cooling, and pumping the solvent and for compression, storage, and transport of the captured CO2, the initial capital, and operating costs of CCUS are high. Per G.E. literature[18], adding a CCUS system with a 90% capture rate to an existing gas-fired power plant will roughly double its capital cost and footprint and cause a 6% - 10% reduction in combined cycle efficiency due to the heat and electrical power required to operate the CCS. The costs are not linear and increase exponentially with carbon capture rates.

According to the EPRI FEED study report, the total installed cost of the retrofit CCS for the Elk Hills facility, which includes two, GE 7FA combustion turbines and a single stream turbine, would be $748MM including a new auxiliary boiler to provide heating steam. The system would consume about 35 MW of electrical power (~ 6% of the nominal plant output) and would achieve a net overall CO2 capture rate of 74%, including CO2 emissions associated with the new boiler. (An alternate design using extraction steam from the combined-cycle plant in lieu of a new boiler would increase the overall CO2 capture rate but would decrease plant output and efficiency by another ~ 6%.) The project costs do not include transportation and storage[19] of the captured CO2.

6.2.2 Barriers to Implementation

The following economic and technological barriers make it unlikely that CCUS could be feasibly implemented to reduce or mitigate CO2 emissions at the CVEC facility:

- Given the costs from the EPRI FEED study report and the fact that the CVEC facility consists of three, not two, GE 7FA combined-cycle units, it is likely that the total installation costs of a comparable system at CVEC would exceed $1B.

[17] *Public Final Report: Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant*, Electric Power Research Institute, January 2022.
[18] *Decarbonizing Gas Turbines through Carbon Capture: A Pathway to Lower CO2*, GE Gas Power, 2021, pgs. 8 – 11.
[19] The facility is in the middle of the Elk Hills Oil field which provides options for both EOR and non-EOR storage.

- Since there are no utilization opportunities or sequestration sites in the vicinity of the CVEC facility, construction of a pipeline would be required to transport the captured CO2 to a suitable storage location (possibly in western NY or PA). At a cost of $2.2MM to $3.9MM per mile[20], not including permitting, this would add another $0.66B to $1.17B to the cost of the project. Permitting for such a pipeline could be costly and difficult to obtain.

- The amount of makeup water required for CCS heating and may exceed the current supply of water to the facility in which case additional sources of water would be required.

- Degradation of the CCS solvent produces ammonia and organic compounds that may increase co-pollutant emissions (see Section 7).

6.3 On-Site Renewable Energy Generation and Storage

6.3.1 Renewable Energy Generation

Per the CLCPA renewable energy targets, generating resources such as solar and wind power will eventually replace fossil-fuel generation in the state. With respect to onsite development of these resources at the CVEC facility, the biggest barrier is the large footprint required.

Land use estimates from the National Renewable Energy Laboratory (NREL)[21] for large scale solar and wind projects are 5.5 – 6.1 acres/MW for photovoltaics and 30 – 44.7 acres/MW for onshore wind. Replacing the nominal 1,000 MW net electrical output capacity of the CVEC facility would, therefore, require around 6,000 acres of solar power generation or 30,000 – 40,000 acres of wind power. The CVEC property is < 200 acres, of which 57 acres are occupied by the combined-cycle facility. Thus, only a small fraction of the CVEC generating capacity could be replaced by on-site solar or wind power.

6.3.2 Energy Storage

Energy storage systems do not provide generating capacity, but they can supply energy for short periods of time, when renewable resources are not generating, or provide other grid support functions. They can, therefore, reduce the need for dispatchable fossil-fueled facilities to operate.

Depending on the type of energy storage, the required footprint may be less than solar or wind power generation. For example, a utility-scale battery storage system of 100 MWh could fit on less than 0.5 acres[22]. Nonetheless, an energy storage system that would replace the facility output for 1 hour would not fit on the CVEC property.

CVEC has not conducted an in-depth evaluation of offsite renewable energy and energy storage opportunities.

[20] Estimated using the *FECM/NETL CO2 Transport Cost Model (2022).*
[21] https://www.nrel.gov/analysis/tech-size.html
[22] https://www.nyserda.ny.gov/All-Programs/Energy-Storage-Program/Energy-Storage-for-Your-Business/Types-of-Energy-Storage

6.4 Reduction in Operations

As noted in the NYISO System Outlook report[23], dispatchable fossil fuel generating resources will be dispatched more frequently but will operate for fewer hours during the year as more renewable energy resources come online and the state transitions to an emission-free grid to meet the CLCPA renewable energy targets. Reduced annual operations will result in lower GHG emissions from these dispatchable fossil fuel sources, including CVEC. As per the draft CAC Scoping Plan[24], the transition to renewable energy resources will be driven by NYSDEC and NY PSC regulations and market initiatives.

7 Co-Pollutant Impacts

The NYSDEC RFAI requests that CVEC provide calculations of co-pollutant emissions from each GHG source if the project is in or impacts a Draft Disadvantaged Community identified by the NYS Climate Justice Working Group and discuss existing measures or alternatives or mitigation measures that will be used to reduce the impact of those emissions. The CVEC facility is in Dutchess County near the intersection of County Route 26 (Cricket Hill Road) and New York Highway 22. The facility is on the northeast boundary of Census Tract 3602704003, which is on the CJWG list of designated Draft Disadvantaged Communities.

7.1 Co-Pollutant Emission Calculations

"Co-pollutants" are defined in ECL Article 75 as hazardous air pollutants (HAPs) produced by greenhouse gas emissions sources. Accordingly, Appendix B contains calculations of short-term (lb/hr) and long-term (tons/yr) potential HAP emissions from the operation of GHG emission sources at the CVEC facility using published emission factors and maximum firing rates[25]. These calculations are consistent with Appendix F of the 2020 Title V renewal application and are a conservative estimate of the worst-case emissions. The actual maximum HAP emissions are expected to be significantly lower because the HAP emissions factors used in Appendix B do not consider the effect of the DLN combustors and oxidation catalysts on total HAP emissions from the combustion turbines and duct burners.

Dry-low NOx (lean-premix) combustion systems typically have lower emission rates of CO, VOC, and VOC HAPs than conventional, diffusion flame combustion systems due to more complete fuel combustion. A 2002 EPA memorandum[26] comparing source test data from diffusion flame and lean pre-mix turbines found that pre-mix turbines had > 85% lower HAP emissions. For the CVEC GE Model 7FA.05 combustion turbines, test data for a similar model suggest that the HAP emission rates may be even lower[27]. The calculations of combustion turbine HAP emissions in Appendix B use a lean-premix turbine emission factor

[23] 2021-2040 System & Resource Outlook (The Outlook): A Report from the New York Independent System Operator, September 22, 2022, pgs. 7 & 8.

[24] Draft Scoping Plan, Appendix A, Power Generation Advisory Panel Recommendations, Initiatives #1 and #14.

[25] For the CTG and DB, the firing rate for the 100% load GE design case at ISO conditions (i.e., 59 deg. F) are used for calculating annual emissions while the maximum design firing rates (i.e., at -8 deg. F) are used for calculating hourly HAP emission rates.

[26] "HAP Emission Factors for Stationary Combustion Turbines" memorandum from Melanie Taylor, Alpha-Gamma Technologies, Inc., to Sims Roy, US EPA OAQPS, 10/23/2002.

[27] An August 2001 GE White Paper on CO emission controls cites CARB Method 430 formaldehyde test results from two, natural gas fired, PG7241FA combustion turbines that are less than 25 ppbvd @ 15% O2 (5.95E-05 lb/MMBTU) which is 8% of the uncontrolled emission factor in AP-42, Table 3.1-3 and 54% of the emission factor used in Appendix B.

from the 2002 EPA memorandum for formaldehyde and uncontrolled emission factors from Table 3.1-3 of US EPA's AP-42, *Compilation of Emissions Factors* for other HAPs; therefore, actual HAP emissions from the turbines will be lower.

The oxidation catalyst used to reduce CO and VOC emissions in the combined combustion turbine and duct burner exhaust will also reduce VOC HAP emissions[28]. The HAP emission factors used in Appendix B do not account for this reduction; therefore, actual emissions will be lower than calculated.

7.2 Co-Pollutant Mitigation Measures

The combination of the CT DLN combustion systems and the oxidation catalysts ensure that VOC HAP emissions from the CTGs and duct burners are as low as feasibly possible. The CVEC facility employs the following additional measures to minimize the impact of HAP emissions from GHG sources:

- The CTGs, DBs and Auxiliary Boiler fire only natural gas fuel. The Title V Permit contains short term VOC emission rate limits for these sources and a facility-wide annual VOC emissions limit which are the "Lowest Achievable Emission Rate" (LAER). Minimizing VOC emission also minimizes emissions of VOC HAPs which constitute the majority of the HAP emissions from gas-fired sources.
- The Emergency Diesel Generator and Diesel Fire Pump engines are subject to NESHAPS (40 CFR 63, Subpart ZZZZ) and NSPS (40 CFR 60, Subpart IIII) requirements including NOx + HC emission standards. These limits and annual VOC limits in the Title V Permit are considered LAER for VOCs. Minimizing VOC emissions also minimizes emissions of VOC HAPs rates from the engines.
- The Emergency Diesel Generator and Diesel Fire Pump engines use only ULSD diesel, which typically contains a low content of trace metals. This minimizes emissions of HAP metals from the engines.
- Operation of the emergency diesel engines is limited to 500 hours per year or less. Operation of the Auxiliary Boiler is limited to 4500 hours per year or less.
- In lieu of a wet cooling tower, the CVEC facility uses air cooled condensers with no emissions. This eliminates the potential for air toxic emissions associated with cooling water treatment chemicals.

CVEC believes these existing measures minimize HAP emissions from GHG sources at the facility to the extent possible and are sufficient to mitigate impacts outside the facility. An Air Toxics Evaluation was submitted with the initial facility permitting information that demonstrated that maximum projected HAP impacts from dispersion modeling were below the NYS Annual and Short Term Guidance Concentrations (AGCs and SGCs).

8 Conclusions

Based on the current (draft) Policy documents and the draft CAC Scoping Plan, CVEC concludes that the requested five-year renewal of its Title V Permit is consistent with the state-wide emission limits in the NYS CLCPA. The Title V renewal application does not include any increase in actual or potential GHG emissions and does not interfere with the attainment of the statewide limits or the CLCPA renewable

[28] A comparison of selected uncontrolled and controlled HAP emission factors in the emission factor documentation for AP-42, Section 3.1 suggests that HAP emissions from combustion turbines equipped with a CO catalyst are ~ 30% - 80% lower than uncontrolled emissions. HAP emissions from the duct burners would be similarly reduced.

energy targets. Per the NYISO Outlook report, dispatchable fossil fuel generation will be required during the transition to renewable sources and CVEC, as the lowest emitting source in the state, can provide that generating capacity with the minimum GHG emissions and co-pollutant impacts. Consequently, CVEC requests that NYSDEC approve the renewal application.

As noted in the Outlook report, "Future uncertainty is the only thing certain about the electric power industry"[29]. CVEC will continue to evaluate ways to reduce or mitigate GHG emissions from its operations in light of future NYSDEC regulations and changing market conditions and will update this analysis at the next Permit renewal.

[29] *2021-2040 System & Resource Outlook (The Outlook)*, September 22, 2022, pg. 76.

Appendix A: GHG Emission Calculations

Cricket Valley Energy Center (CVEC) Maximum Potential GHG Emissions (including upstream emissions)

GHG Emission Factors & Global Warming Potentials Used in Calculations

Emission Unit and Fuel Type	GHG Emission Factors						Source
	Units	CO_2	CH_4	N_2O	CO_2e (GWP-20)	CO_2e (GWP-100)	
Combustion Turbines and Duct Burners firing Natural Gas	kg/MMBTU	---	0.001	0.0001	---	---	40 CFR 75, App. G, Eq. G-4 (CO_2); 40 CFR 98, Table C-2 (CH_4 & N_2O)
	lb/MMBTU	118.9	0.0022	0.00022	119.1	119.0	
Aux. Boiler firing natural gas	kg/MMBTU	53.06	0.001	0.0001	---	---	40 CFR 98, Tables C-1 & C-2; (Permit Limit for CO_2e is 119 lb/MMBTU)
	lb/MMBTU	117.0	0.0022	0.00022	117.2	117.1	
Diesel engines firing #2 fuel oil (ULSD)	kg/MMBTU	73.96	0.003	0.0006	---	---	40 CFR 98, Tables C-1 & C-2
	lb/MMBTU	163.1	0.0066	0.0013	164.0	163.6	
Upstream emission factors for natural gas imported into NYS	kg/MMBTU	12.13	0.36	0.00014	42.147	43.147	Appendix A from the NYSDEC *2021 Statewide Greenhouse Gas Emissions Report*
	lb/MMBTU	26.74	0.7870	0.0003	92.92	95.12	
Upstream emission factors for diesel fuel imported into NYS	kg/MMBTU	15.16	0.1210	0.00026	25.375	26.375	
	lb/MMBTU	33.43	0.2668	0.0006	55.94	58.15	
20-year Global Warming Potentials (GWP-20)	---	1	84	264	---	---	6 NYCRR 496.5
100-year Global Warming Potentials (GWP-100)	---	1	25	298	---	---	40 CFR 98, Table A-1

Maximum Potential GHG Emissions from Combustion		Each CTG[1]	Each DB[1]	Total for All CT-DB[1]	Aux. Blr	Emer. Dsl. Gen.[2]	Dsl. Fire Pump[2]	Facility
Fuel Type	---	natural gas			natural gas	diesel fuel oil		---
Design Heat Input Capacity	MMBTU/hr	2,396	247	7,928	60	14.9	1.8	---
@ ISO Conditions	MMBTU/hr	2,333	184	7,551	---	---	---	---
Max. Annual Operations	hours	8,760	8,760	8,760	4,500	500	500	---
Max. Annual Heat Input	MMBTU	20,437,080	1,611,840	66,146,760	270,000	7,452	900	66,425,112
Calculated Maximum Annual GHG Emissions (tons/year)	CO_2	1,214,546	95,789	3,931,007	15,792	608	73.4	3,947,480
	CH_4	23	2	73	0.3	0.02	0.003	73
	N_2O	2	0	7	0.03	0.005	0.0006	7
	CO_2e[3]	1,217,034	95,986	3,939,057	15,825	611	74	3,955,567
Permit Limits on Potential GHG Emissions (tons/year)	CO_2e[4]	---	---	---	---	595	74	3,593,609
						Equivalent facility-wide limit based on GWP-20:		3,597,312

Maximum Potential Upstream GHG Emissions		Natural Gas	Diesel Fuel Oil	Total
Max. Fuel Use w/o Exceeding Annual GHG Emission Limits[5]	MMBTU	60,400,722	8,149	60,408,872
Calculated Maximum Annual Upstream GHG Emissions (tons/year)	CO_2	807,673	136	807,809
	CH_4	23,769	1.1	23,770
	N_2O	9	0.002	9
	CO_2e	2,806,713	228	2,806,942

Facility Total Potential GHG Emissions (tons/year, CO_2e, GWP20)	
Direct Emissions	3,597,312
Upstream Emissions	2,806,942
Total Potential GHG Emissions	6,404,254

Notes:

1. The CTG and DB heat input rates for the 100% load GE design case at ISO conditions (59 deg. F, 1 atm. and 60% R.H.) are used for calculating annual emissions.
2. Diesel engine design capicity based on full load fuel consumption rates from manufacturer's specifications (i.e., 108 gph & 12.7 gph for the EDG and DFP, respectively) and the default heating value (0.138 MMBTU/gal) from 40 CFR 98, Table C-1.
3. Calculated using 20-year GWPs.
4. Title V Permit limitd on annual GHG (CO_2e) emissions based on 100-year GWPs.
5. Based on the lower of the Max. Annual Heat Input values in the Potential GHG Emissions Table above or the maximum fuel use that does not result in the exceedance of an annual GHG emissions limit in the Title Permit as follows:

- Max. annual diesel fuel use for the diesel fire pump = 876 MMBTU
- Max. diesel fuel use w/o exceeding annual GHG permit limit for the emergency diesel generator = 7273 MMBTU

[(595 tons CO2e limit) x (2000 lbs/ton) / 163.6 lb/MMBTU]

- Max. annual natural gas use for the auxiliary boiler = 270,000 MMBTU
- Max. naural gas use in the CTG/DB without exceeding the facility-wide annual GHG permit limit = 60,130,722 MMBTU

[2000 lbs/ton x (3,593,609 tons CO2e (facility limit) - 595 tons CO2e (EDG limit) - 74 tons (DFP limit) - 15,825 tons CO2e (AB potential emiss.)) / 119.0 lb/MMBTU CO2e]

Cricket Valley Energy Center (CVEC) Actual GHG Emissions from Combustion Sources

GHG Emission Factors & Global Warming Potentials Used in Calculations

Emission Unit and Fuel Type	GHG Emission Factors (lb/MMBTU)				Fuel Heat Value	Source
	CO2	CH4	N2O	CO2e		
Combustion Turbines and Duct Burners firing Natural Gas	118.86	0.0022	0.00022	119.1	---	40 CFR 98, Table C-2 (CH4 & N2O) 40 CFR 75, App. G, Eq. G-4 (CO2)
Aux. Boiler firing natural gas	116.98	0.0022	0.00022	117.2	1.026E-03 MMBTU/scf	40 CFR 98, Tables C-1 & C-2
Diesel engines firing #2 fuel oil (ULSD)	163.05	0.0066	0.0013	164.0	0.138 MMBTU/gal	40 CFR 98, Tables C-1 & C-2
Upstream emission factors for natural gas imported into NYS	26.74	0.7870	0.0003	92.9	---	Appendix A from the NYSDEC *2021 Statewide Greenhouse Gas Emissions Report*
Upstream emission factors for diesel fuel imported into NYS	33.43	0.2668	0.0006	56.0	---	
Global Warming Potentials (GWP-20)	1	84	264	---	---	Per 6 NYCRR 496.5

Combustion Turbine and Duct Burner Heat Input & CO2 Emissions[1]

Quarter	Heat Input (MMBTU)				CO2 Emissions (tons)			
	CT-DB 1	CT-DB 2	CTDB 3	CT-DB Total	CT-DB 1	CT-DB 2	CTDB 3	CT-DB Total
4th Quarter 2020	1,262,848	1,891,582	2,466,295	5,620,725	75,049	112,414	146,567	334,030
1st Quarter 2021	853,617	1,082,081	802,636	2,738,334	50,731	64,306	47,699	162,735
2nd Quarter 2021	3,287,464	3,599,160	3,323,742	10,210,366	195,373	213,894	197,525	606,792
3rd Quarter 2021	4,213,030	4,294,696	4,396,655	12,904,381	250,404	255,229	261,292	766,925
4th Quarter 2021	2,569,871	3,195,017	3,330,017	9,094,905	152,739	189,876	197,900	540,514
1st Quarter 2022	1,056,016	1,070,436	991,413	3,117,865	62,758	63,615	58,920	185,293
2nd Quarter 2022	3,834,499	4,368,131	3,786,874	11,989,504	227,879	259,594	225,052	712,525
3rd Quarter 2022	4,072,956	4,832,357	4,476,145	13,381,458	242,063	287,192	266,026	795,281
Total	21,150,302	24,333,460	23,573,777	69,057,539	1,256,994	1,446,121	1,400,981	4,104,096
Annual Average	---	---	---	34,528,769	---	---	---	2,052,048

CVEC Annual Average Heat Input and GHG Emissions		Auxiliary Boiler[2]	Emer. Dsl. Gen.[2]	Diesel Fire Pump[2]	Total CT-DB[1] (Avg. 4Q20 - 3Q22)	Upstream Emissions	
						Natural Gas	ULSD
Annual Fuel Use (MCF/yr, gals/yr)	2020	49,340	611	156	---	---	---
	2021	34,000	561	253			
	Average	41,670	586	205			
Annual Heat Input (MMBTU/yr)	2020	50,623	84	22	---	---	---
	2021	34,884	77	35	---	---	---
	Average	42,753	81	28	34,528,769	34,571,523	109
CO2 Emissions	tons/year	2,501	7	2	2,052,048	462,287	1.82
CH4 Emissions	tons/year	0.06	0.0003	0.00007	38	13,605	0.01
N2O Emissions	tons/year	0.006	0.00006	0.000014	4	5	0.00
CO2e Emissions	tons/year	2,507	7	2	2,056,250	1,606,477	3

Notes:

1. Combustion turbine and duct burner (CT-DB) heat input and CO2 emissions from quarterly reports to US EPA.
2. Auxiliary Boiler and diesel engine emissions calculated from fuel use reported in the 2020 & 2021 annual Emission Statements submitted to NYSDEC.

		Direct Emissions from Fuel Consumption				Upstream Emissions		
Actual GHG Emissions		CT-DB Total	Aux. Blr	Emer. Dsl. Gen.	Dsl. Fire Pump	Natural Gas	Diesel Fuel	Facility Total
Total GHG Emissions (tons/yr CO2e)	24-month average	2,056,250	2,507	7	2	1,606,477	3	3,665,245
Estimate of Projected 2030 & 2050 Emissions								
Total GHG Emissions (tons/yr CO2e)	2030	2,056,250	2,507	7	2	1,606,477	3	3,665,245
	2050	0	2,507	7	2	1,956	3	4,475

Appendix B: Co-pollutant (HAP) Emission Calculations

Cricket Valley Energy Center (CVEC) Maximum Potential Hazadous Air Pollutant (HAP) Emissions

						Each CTG[4]		Each DB[4]		Total for All CT-DB[4]		Auxiliary Boiler		Emergency Diesel. Generator[5]		Diesel Fire Pump[5]		Facility Total	
						Maximum	ISO Cond.	Maximum	ISO Cond.	Maximum	ISO Cond.								
Design Capacity (MMBTU/hr)						2,396	2,333	247	184	7,928	7,551	60		15.6		1.8		---	---
Max. Annual Operations (hours)						---	8,760	---	8,760	---	8,760	---	4,500	---	500	---	500	---	8,760
Max. Annual Heat Input (MMBTU)						---	20,437,080	---	1,611,840	---	66,146,760	---	270,000	---	7,825	---	876	---	66,425,461
Co-Pollutant Emission Factors (lb/MMBTU)						**Maximum Potential Co-Pollutant Emissions**													
Hazadous Air Pollutant	**CT[1]**	**DB & Aux. Blr.[2]**	**Emer. Dsl. Gen.[3]**	**Dsl. Fire Pump[3]**	**NYSDEC HAP**	**Each CTG**		**Each DB**		**Total for All CT-DB**		**Auxiliary Boiler**		**Emer. Dsl. Gen.**		**Diesel Fire Pump**		**Facility Total**	
						lb/hr	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**
Acetaldehyde	4.00E-05	---	2.52E-05	7.67E-04	X	9.58E-02	0.41	---	---	2.87E-01	1.23	---	---	3.94E-04	0.000	1.34E-03	0.000	2.9E-01	1.2
Acrolein	6.40E-06	---	7.88E-06	9.25E-05	X	1.53E-02	0.07	---	---	4.60E-02	0.20	---	---	1.23E-04	0.000	1.62E-04	0.0000	4.6E-02	0.2
Benzene	1.20E-05	2.06E-06	7.76E-04	9.33E-04	X	2.87E-02	0.12	5.09E-04	0.00	8.78E-02	0.37	1.24E-04	0.00	1.21E-02	0.003	1.64E-03	0.0003	1.0E-01	0.4
1,3-Butadiene	4.30E-07	---	---		X	1.03E-03	0.00	---	---	3.09E-03	0.01	---	---	---	---	0.00E+00	---	3.1E-03	0.0
Dichlorobenzene	---	1.18E-06	---			---	---	2.91E-04	0.00	8.72E-04	0.00	7.06E-05	0.00	---	---	0.00E+00	---	9.4E-04	0.0
Ethylbenzene	3.20E-05	---	---		X	7.67E-02	0.33	---	---	2.30E-01	0.98	---	---	---	---	0.00E+00	---	2.3E-01	1.0
Formaldehyde	1.11E-04	7.35E-05	7.89E-05	1.18E-03	X	2.66E-01	1.13	1.82E-02	0.06	8.52E-01	3.58	4.41E-03	0.01	1.23E-03	0.000	2.07E-03	0.0000	8.6E-01	3.6
Hexane	---	1.76E-03	---		X	---	---	4.36E-01	1.42	1.31E+00	4.27	1.06E-01	0.24	---	---	0.00E+00	---	1.4E+00	4.5
Naphthalene	1.30E-06	5.98E-07	1.30E-04	8.48E-05		3.11E-03	0.01	1.48E-04	0.00	9.79E-03	0.04	3.59E-05	0.00	2.03E-03	0.001	1.49E-04	0.0001	1.2E-02	0.0
Propylene Oxide	2.90E-05	---	---		X	6.95E-02	0.30	---	---	2.08E-01	0.89	---	---	---	---	0.00E+00	---	2.1E-01	0.9
Toluene	1.30E-04	3.33E-06	2.81E-04	4.09E-04	X	3.11E-01	1.33	8.23E-04	0.00	9.37E-01	3.99	2.00E-04	0.00	4.40E-03	0.001	7.17E-04	0.0001	9.4E-01	4.0
Xylene (Total)	6.40E-05	---	1.93E-04	2.85E-04	X	1.53E-01	0.65	---	---	4.60E-01	1.96	---	---	3.02E-03	0.001	4.99E-04	0.0001	4.6E-01	2.0
Total Organic HAPs	**4.27E-04**	**1.85E-03**	**1.49E-03**	**3.75E-03**	X	**1.02**	**4.35**	**0.46**	**1.49**	**4.43E+00**	**17.53**	**1.11E-01**	**0.25**	**2.33E-02**	**0.006**	**6.57E-03**	**0.0007**	**4.6E+00**	**17.8**
Acenaphthene	---	1.76E-09	4.68E-06	1.42E-06		---	---	4.36E-07	0.00	1.31E-06	0.00	1.06E-07	0.0	7.32E-05	0.000	2.49E-06	0.000	7.7E-05	0.0
Acenaphthylene	---	1.76E-09	9.23E-06	5.06E-06		---	---	4.36E-07	0.00	1.31E-06	0.00	1.06E-07	0.0	1.44E-04	0.000	8.87E-06	0.000	1.5E-04	0.0
Anthracene	---	2.35E-09	1.23E-06	1.87E-06		---	---	5.81E-07	0.00	1.74E-06	0.00	1.41E-07	0.00	1.92E-05	0.000	3.28E-06	0.0000	2.4E-05	0.0
Benzo(a)anthracene	---	1.76E-09	6.22E-07	1.68E-06		---	---	4.36E-07	0.00	1.31E-06	0.00	1.06E-07	0.00	9.73E-06	0.000	2.94E-06	0.0000	1.4E-05	0.0
Benzo(a)pyrene	---	1.18E-09	2.57E-07	1.88E-07		---	---	2.91E-07	0.00	8.72E-07	0.00	7.06E-08	0.00	4.02E-06	0.000	3.29E-07	0.0000	5.3E-06	0.0
Benzo(b)fluoranthene	---	1.76E-09	1.11E-06	9.91E-08		---	---	4.36E-07	0.00	1.31E-06	0.00	1.06E-07	0.00	1.74E-05	0.000	1.74E-07	0.0000	1.9E-05	0.0
Benzo(g,h,i)perylene	---	1.18E-09	5.56E-07	4.89E-07		---	---	2.91E-07	0.00	8.72E-07	0.00	7.06E-08	0.00	8.70E-06	0.000	8.57E-07	0.0000	1.1E-05	0.0
Benzo(k)fluoranthene	---	1.76E-09	2.18E-07	1.55E-07		---	---	4.36E-07	0.00	1.31E-06	0.00	1.06E-07	0.00	3.41E-06	0.000	2.72E-07	0.0000	5.1E-06	0.0
Chrysene	---	1.76E-09	1.53E-06	3.53E-07		---	---	4.36E-07	0.00	1.31E-06	0.00	1.06E-07	0.00	2.39E-05	0.000	6.19E-07	0.0000	2.6E-05	0.0
Dibenz(a,h)anthracene	---	1.18E-09	3.46E-07	5.83E-07		---	---	2.91E-07	0.00	8.72E-07	0.00	7.06E-08	0.00	5.41E-06	0.000	1.02E-06	0.0000	7.4E-06	0.0
7,12-Dimethylbenz(a)anthracene	---	1.57E-08	---	---		---	---	3.87E-06	0.00	1.16E-05	0.00	9.41E-07	0.0	---	---	---	---	1.3E-05	0.0
Fluoranthene	---	2.94E-09	4.03E-06	7.61E-06		---	---	7.26E-07	0.00	2.18E-06	0.00	1.76E-07	0.00	6.31E-05	0.000	1.33E-05	0.0000	7.9E-05	0.0
Fluorene	---	2.75E-09	1.28E-05	2.92E-05		---	---	6.78E-07	0.00	2.03E-06	0.00	1.65E-07	0.00	2.00E-04	0.000	5.12E-05	0.0000	2.5E-04	0.0
Indeno(1,2,3-cd)pyrene	---	---	4.14E-07	3.75E-07		---	---	---	---	0.00E+00	0.00	---	---	6.48E-06	0.000	6.57E-07	0.0000	7.1E-06	0.0
3-Methylchloranthrene	---	1.76E-09	---	---		---	---	4.36E-07	0.00	1.31E-06	0.00	1.06E-07	0.0	---	---	---	---	1.4E-06	0.0
2-Methylnaphthalene	---	2.35E-08	---	---		---	---	5.81E-06	0.00	1.74E-05	0.00	1.41E-06	0.0	---	---	---	---	1.9E-05	0.0
Phenanthrene	---	1.72E-08	4.08E-05	2.94E-05		---	---	4.24E-06	0.00	1.27E-05	0.00	1.03E-06	0.00	6.38E-04	0.000	5.15E-05	0.0000	7.0E-04	0.0
Pyrene	---	4.90E-09	3.71E-06	4.78E-06		---	---	1.21E-06	0.00	3.63E-06	0.00	2.94E-07	0.00	5.81E-05	0.000	8.38E-06	0.0000	7.0E-05	0.0
Total PAH (except Naphthalene)	**9.00E-07**	**8.52E-08**	**8.15E-05**	**8.33E-05**		**2.16E-03**	**0.01**	**2.10E-05**	**0.00**	**6.31E-05**	**0.00**	**5.11E-06**	**0.00**	**1.28E-03**	**0.000**	**1.46E-04**	**0.000**	**1.5E-03**	**0.0**
Arsenic	---	1.96E-07	2.59E-07	2.59E-07	X	---	---	4.84E-05	0.00	1.45E-04	0.00	1.18E-05	0.00	4.05E-06	0.000	4.54E-07	0.0000	1.6E-04	0.0
Beryllium	---	1.18E-08	---	---	X	---	---	2.91E-06	0.00	8.72E-06	0.00	7.06E-07	0.00	---	---	---	---	9.4E-06	0.0
Cadmium	---	1.08E-06	---	---	X	---	---	2.66E-04	0.00	7.99E-04	0.00	6.47E-05	0.00	---	---	---	---	8.6E-04	0.0
Chromium	---	1.37E-06	---	---	X	---	---	3.39E-04	0.00	1.02E-03	0.00	8.24E-05	0.00	---	---	---	---	1.1E-03	0.0
Cobalt	---	8.24E-08	2.59E-07	2.59E-07	X	---	---	2.03E-05	0.00	6.10E-05	0.00	4.94E-06	0.00	4.05E-06	0.000	4.54E-07	0.0000	7.0E-05	0.0
Lead	---	4.90E-07	2.59E-07	2.59E-07	X	---	---	1.21E-04	0.00	3.63E-04	0.00	2.94E-05	0.00	4.05E-06	0.000	4.54E-07	0.0000	4.0E-04	0.0
Manganese	---	3.73E-07	2.59E-07	2.59E-07	X	---	---	9.20E-05	0.00	2.76E-04	0.00	2.24E-05	0.00	4.05E-06	0.000	4.54E-07	0.0000	3.0E-04	0.0
Mercury	---	2.55E-07	2.59E-07	2.59E-07	X	---	---	6.30E-05	0.00	1.89E-04	0.00	1.53E-05	0.00	4.05E-06	0.000	4.54E-07	0.0000	2.1E-04	0.0
Nickel	---	2.06E-06	6.57E-06	6.57E-06	X	---	---	5.09E-04	0.00	1.53E-03	0.00	1.24E-04	0.00	1.03E-04	0.000	1.15E-05	0.0000	1.8E-03	0.0
Selenium	---	2.35E-08	2.59E-07	2.59E-07	X	---	---	5.81E-06	0.00	1.74E-05	0.00	1.41E-06	0.00	4.05E-06	0.000	4.54E-07	0.0000	2.3E-05	0.0
Total HAP Metals	**0.00E+00**	**5.94E-06**	**8.12E-06**	**8.12E-06**		**0.00E+00**	**0.00**	**1.47E-03**	**0.00**	**4.40E-03**	**0.01**	**3.56E-04**	**0.00**	**1.27E-04**	**0.000**	**1.42E-05**	**0.000**	4.9E-03	0.0
Total HAP Emissions (TPY)							**4.36**		**1.49**		**17.54**		**0.25**		**0.006**		**0.001**	**4.6**	**17.8**

Notes:

1. Combustion Turbine (CT) emission factors, except formaldehyde, are from Tables 3.1-3 and 3.1.4 of *AP-42: Compilation of Air Emissions Factors* and are for diffusion-flame cobustion turbines. The emission factor for formaldehyde is for lean-premix turbines at >80% load and is the 95th upper percentile value from Table 9 in the

2. Emission factors for duct burners and axuliary boiler are from Tables 1.4-3 and 1.4-4 of AP-42 and do not account for any reduction in DB HAP emissions due to the oxidation catalysts.

3. Organic HAP emission factors for the emergency diesel gen3erator and the fire pump engine are from Tables 3.3-2, 3.4-3 and 3.4-4 of AP-42. HAP metal emission factors for the diesel engines are based on the test results for ULSD in the NYSERDA *Updated Determination of Sulfur and Other Trace Element Content of Fuel Oil in New York State - Final Report, July 2017*.

4. The CTG and DB heat input rates for the 100% load GE design case at ISO conditions (59 deg. F, 1 atm. and 60% R.H.) are used for calculating annual emissions. The worst case (-8 deg. F) heat input rates are used for calculating the hourly HAP emission rates.

5. Diesel engine design capicity based on max. fuel consumption from manufacturer's specifications (i.e., 113.4 gph & 12.7 gph for the EDG and DFP, respectively) and the default heating value (0.138 MMBTU/gal) from 40 CFR 98, Table C-1..