CHAPTER 2 OPERATION PERMIT TECHNICAL SUPPORT MEMORANDUM

TO: File

FROM: Stephen S. Ours, P.E. SSO
Chief, Permitting Branch

Abraham T. Hagos ATH
Environmental Engineer

SUBJECT: U.S. General Services Administration
Central Heating and Refrigeration Plant
Permit No. 5197-R1 to Operate the Cogeneration System

DATE: July 11, 2022

BACKGROUND INFORMATION

A permit renewal application to operate the cogeneration system at the U.S. General Services Administration (GSA) Central Heating and Refrigeration Plant (CHRP), located at 13th and C Streets SW, was received by the Air Quality Division (AQD) on July 23, 2018. This application was to renew and update expired permit No. 5197, issued May 20, 2002.

This permit makes significant revisions from the previous permit to reflect changed and new regulations, regulatory interpretations, and make other corrections and updates.

The permit action will be published in the DC Register and on DOEE's website on July 22, 2022. Public comments for the permit action will be solicited through August 22, 2022.

GSA has not requested that any of the materials submitted with this application be held confidential.

REGULATORY REVIEW

20 DCMR Chapter 2, Section 200: General Permit Requirements:
GSA CHRP is a stationary source of criteria and other air pollutants. The applicant is requesting a renewed operating permit for a cogeneration system consisting of two combustion turbines as well as duct burners with heat input ratings exceeding 5 MMBTU/hr. Thus a Chapter 2 permit is required.

Chapter 2, Section 209: Permit Requirements For Minor New Source Review:
Effective January 1, 2014, the requirements of this section are applicable to any source required to obtain a Chapter 2 permit to construct a new stationary source, modify an existing stationary source, or install or modify an air pollution control device on a stationary source that results in an

increase of potential to emit (PTE) rate equal to or greater than five tons per year (5 TPY) from an individual unit of any of the criteria pollutants. The cogeneration system was installed in 2002, thus, the cogeneration renewal is not subject to the requirements of 20 DCMR 209.

20 DCMR Chapter 3, Section 301: Operating Permit Requirements:
The GSA CHRP is a major source subject to this chapter (commonly known as "Title V") and is required to obtain and maintain an operating permit in accordance with 20 DCMR 300.1 for the cogeneration system. GSA has already included the equipment covered by this permit in a pending Title V permit renewal application. This is reflected in Condition I(g) of the permit.

20 DCMR Chapter 5, Section 500: Source Monitoring and Testing Requirements:
Chapter 5 authority was used to ensure that all appropriate monitoring and testing is required to ensure compliance with the emission and operational requirements of the permit and applicable regulations is established in the permit. Among other requirements related to this regulation, the Permittee will be required to perform stack testing to determine compliance with emission limits, operate continuous emission monitors (CEMS) and continuous opacity monitors (COMS), maintain written records of fuel usage and emissions from the equipment, and maintain records of other monitored data. These requirements have been established throughout the permit document, but especially in Conditions IV and V.

20 DCMR Chapter 6, Section 600: Fuel Burning Particulate Emission:
Total suspended particulate matter (TSP) (also known as total filterable PM) emissions from the cogeneration system shall not exceed the following: 0.05 pounds per MMBTU from the duct burner system. It should be noted that the duct burners meet the definition of "fuel burning equipment", but the combustion turbines do not. This requirement is contained in Condition II(f) of the permit. Performance tests to determine if the emission limit is being met are required pursuant to Condition IV(h).

20 DCMR Chapter 6, Section 606: Visible Emissions:
The cogeneration system began initial operation after January 1, 1977. Therefore, the base standard would be a zero percent standard except that discharges not exceeding forty percent (40%) opacity (unaveraged) shall be permitted for two (2) minutes in any sixty (60) minute period and for an aggregate of twelve (12) minutes in any twenty-four hour (24 hr.) period during start-up, cleaning, soot blowing, adjustment of combustion controls, or malfunction of equipment.

An exception to the above requirement for the cogeneration system can be granted to establish an emission limit of up to 10% opacity in certain circumstances pursuant to 20 DCMR 606.3. GSA provided justification for a 5% opacity standard in a letter dated January 14, 2020 associated with their renewal application. This justification explained why the equipment meets the standards set forth for an alternate opacity standard in 20 DCMR 606.3. Based on this evaluation and the fact that the compliance determination method is the use of COMS, which, as a result of the limitations of their technology, fluctuate around the true opacity slightly, and would therefore never show compliance with an instantaneous zero percent opacity standard, such as that in 20 DCMR 606.1, the Department has granted a 5% opacity standard pursuant to 20 DCMR 606.3. This standard has been reflected in Condition II(e) of the permit.

Additionally, it should be noted that 20 DCMR 606 is subject to a call for a State Implementation Plan (SIP) revision from EPA, commonly referred to as the "Startup, Shutdown, and Malfunction SIP call". The Department is evaluating potential revisions to the regulation which would potentially change and supersede the visible emissions requirements for the cogeneration system. This is reflected in notes incorporated in the permit condition.

As noted above, GSA intends to continue to use COMS to monitor for compliance with the opacity standards in order to ensure continuous compliance with visible emissions standards. As such, appropriate requirements related to the installation, certification, operation, and maintenance of the COMS equipment have been incorporated into the permit. These requirements generally reflect the requirements for COMS incorporated in 40 CFR 60.

<u>20 DCMR Chapter 8, Section 801.3: Sulfur Content of Fuel:</u>

The purchase, sale, offer for sale, storage, transport, or use of number two (No. 2) commercial fuel oil limitation of 20 DCMR 801.3 is applicable to GSA. On and after July 1, 2018, the purchase, sale, offer for sale, storage, transport, or use of number two (No. 2) commercial fuel oil is prohibited if it contains more than fifteen parts per million (15 ppm) or fifteen ten-thousandths percent (0.0015%) by weight of sulfur, unless otherwise specified in § 801.5. There is an exception in the regulation for use of fuel purchased before the applicability date of the standard. However, during the permitting process, GSA submitted documentation that all fuel stored for use in these units has sulfur contents less than 15 ppm already. As such, no special language is needed to address old fuel stored at the facility.

Therefore, a limit of 0.0015% sulfur by weight has been included in Condition III(d) of the permit.

Note that AQD evaluated the applicability of this standard to the CHP process. The 15 ppm standard of 20 DCMR 801.2 could arguably not be applicable to the combustion turbine itself because the combustion turbine does not use indirect heat transfer to produce electrical power (see the definition of "fuel burning equipment" in 20 DCMR 199, which is a term used in the definition of "commercial fuel oil" used in 20 DCMR 801.2 and defined in 20 DCMR 899). However, AQD determined that the 15 ppm requirement does apply for two reasons. First, the steam production of the "Boiler 5" heat recovery steam generation system, which does use indirect heat transfer, is arguably the "primary" purpose for the CHP system since the CHRP is primarily dedicated to steam production for heating purposes and the CHP system was installed in lieu of an upgraded boiler to improve efficiency of fuel usage. Second, the fuel oil in the tank is also used in the other boilers at the site to which the 15 ppm sulfur requirement is clearly applicable, thus the fuel oil itself should be classified as "commercial fuel oil" even if not entirely used for equipment subject to this standard.

20 DCMR Chapter 8, Section 804.1: Nitrogen Oxides Emissions:
The equipment (both the combustion turbines and the duct burners) meets the definition of a fossil-fuel-fired steam-generating unit with a heat input greater than 100 MMBTU/hr. Therefore, this regulation is applicable and the unit shall not discharge NO_x in excess of the limits set forth in Appendix 8-1. This requirement is stipulated in Condition II(d)(4) of the permit. Compliance will be monitored with the use of NOx CEMS.

20 DCMR Chapter 8, Section 805: Reasonably Available Control Technology for Major Stationary Sources of the Oxides of Nitrogen:
Because the facility meets the definition of a major stationary source having the potential to emit 25 tons per year of NOx or more, this regulation applies to the facility pursuant to 20 DCMR 805.1(a).

This equipment covered by this permit is specifically subject to section 805.4 which governs stationary combustion turbines. The system is subject to 805.4(a)(2) as the combustion turbines have heat input ratings in excess of 50 MMBTU/hr and construction on the equipment began before February 18, 2005.

When being fired on natural gas, each combustion turbine is subject to a 25 ppmvd NOx standard (corrected to 15% oxygen) per 805.4(a)(2)(A)(i). See Condition II(d)(1)(i) of the permit. The combustion turbines are not subject to the standards for when they are burning liquid fuel because they are limited to operating consistent with the limitations in 805.4(a)(2)(D)(i) through (iii). See Conditions II(d)(1)((ii), III(a) through (d), and V(e) and (f) of the permit. In addition to the above limits, emissions from the stationary combustion turbines and all duct burners combined are required to meet a limit of 0.20 lb/MMBTU NOx on a calendar day average when fired on any fuel or combination of fuels pursuant to 805.4(a)(2)(B). This requirement is contained in Condition II(d)(2) of the permit.

The facility has elected to show compliance with the 25 ppmvd standard of 805.4(a)(2)(A)(i) with the use of CEMS as allowed by 805.4(b)(1). In accordance with the referenced 805.10(a)(1), because 20 DCMR 1002 is applicable to the facility, GSA has the option to comply with 40 CFR 75 NOx CEMS requirements in lieu of 40 CFR 60, Appendix B.

It should be noted that some aspects of 40 CFR 75 do not apply to this equipment, such as many of the EPA reporting requirements, as they are relevant only to units fully subject to 40 CFR 75, not just the CEMS requirements. These portions of 40 CFR 75 requirements have not been included in the permit.

20 DCMR Chapter 9, Section 903: Odorous or Other Nuisance Air Pollutants:
"An emission into the atmosphere of odorous or other air pollutants from any source in any quantity and of any characteristic, and duration which is, or is likely to be injurious to the public health or welfare, or which interferes with the reasonable enjoyment of life or property is prohibited [20 DCMR 903.1]" is applicable to all sources. This requirement is contained in Condition II(g) of the permit.

20 DCMR Chapter 10: Nitrogen Oxides Emissions Budget Program:
This regulation is applicable to the equipment covered by this permit (the two combustion turbines and the duct burners) in combination with Boilers 3 and 4 at the facility. It requires emissions from these three units to not exceed 25 tons per control period (May 1 - September 30 each year, inclusive). It additionally requires NOx monitoring via CEMS pursuant to the procedures in 40 CFR 75, Subpart H. The requirements of this regulation have been incorporated throughout the permit.

40 CFR 52.470(d): EPA-Approved District of Columbia Source Specific Requirements:
This portion of the District's State Implementation Plan (SIP) incorporates the majority of an October 21, 1997 permit issued by the District to GSA and covering CHRP and the now demolished West Heating Plant (WHP). Many of the requirements are no longer relevant to the equipment covered by this proposed permit 5197-R1, in large part due to the reconstruction of the former Boiler 5 into a cogeneration system with combustion turbines and duct burners. However, one aspect of the permit that is relevant is a requirement for all of the boilers at the facility to use CEMS and operate and maintain them in accordance with 40 CFR 60, Appendix F.

As discussed in the note associated with Condition IV(a)(4) of the proposed permit, AQD has determined that 40 CFR 75 CEMS are at least as stringent as 40 CFR 60 CEMS, and is therefore streamlining this requirement with other CEMS requirements.

Additionally, a requirement to operate Boiler 5, which contains the duct burner system, for no more than 11 months per year with a 30-day shutdown period has also been transferred to the new permit as Condition III(h). The associated record keeping requirement is found in Condition III(m).

40 CFR Part 60 Subpart Db – New Source Performance Standards (NSPS) Industrial-Commercial- Institutional Steam Generating Units:
NSPS Subpart Db applies to steam generating units with a heat input capacity greater than 100 MMBtu per hour and construction, modification or reconstruction of which commenced after June 19, 1984. Per 40 CFR 60.40b(i), the stationary combustion turbine emissions are subject to 40 CFR 60, Subpart GG in lieu of Subpart Db, but the heat recovery steam generator with duct burners is subject to Subpart Db as the duct burners have a heat input rating in excess of 100 MMBTU/hr. The "affected facility" under this regulation is therefore the heat recovery steam generator (HRSG) and associated duct burners, which are natural gas-fired only. Their total rated

heat input is 211 MMBTU/hr (HHV basis). The unit is considered to have been reconstructed in 2002.

Based on this information and a review of Subpart Db, the following sections and requirements apply (or do not apply) as follows:

40 CFR 60.42b, Standard for sulfur dioxide (SO2) is not applicable because the HRSG with duct burners combust only gaseous fuel (natural gas). There is no applicable sulfur limit pursuant to 40 CFR 60.42b(k)(2). As such, when keeping records pursuant to 40 CFR 60.49b(r), the fuel supplier certifications do not need to state the sulfur content, but just prove that the natural gas meets the definition in 40 CFR 60.41b.

40 CFR 60.43b, Standard for particulate matter (PM) is also not applicable because the HRSG with duct burners combust only natural gas and none of the fuels covered by this section.

40 CFR 60.44b, Standard for nitrogen oxides (NO2) is applicable. In particular, because the affected unit is effectively a duct burner used in a combined cycle system burning natural gas only, 40 CFR 60.44b(a)(4)(i) applies. Based on this determination, the NOx emission limit is 0.20 lb/MMBTU.[1] This limit is contained in Condition II(d)(5) of the permit. Note that 40 CFR 60.44b(j) does not apply because the affected facility is not limited to an annual capacity factor of 10% or less, and as such 40 CFR 60.44b(k), which would potentially exempt the affected facility from emission limits under this section also does not apply.

Note that 40 CFR 60.49b(p) does not apply because the duct burners (affected facility) are not limited to a 10% annual capacity factor.

Also note that, while CEMS are required under other programs, pursuant to 40 CFR 60.48b(b) and 40 CFR 60.48b(h), CEMS for NOx are not required for the "affected facility" (duct burners) as the emission limit for NOx from Subpart Db arises from 40 CFR 60.44b(l). However, because CEMS are required for other programs, GSA will elect to use CEMS for compliance pursuant to 40 CFR 60.46b(f)(2).

Compliance will be demonstrated as specified in 40 CFR 60.46b. Monitoring, record keeping, and reporting shall be completed as specified in 40 CFR 60.48b and 60.49b.

40 CFR Part 60 Subpart GG – New Source Performance Standards (NSPS) Stationary Gas Turbine Units:

NSPS Subpart GG Standards of performance for Stationary Gas Turbines applies to gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating

[1] For a full evaluation of the applicability of 40 CFR 60.44b, reference the memorandum prepared for GSA by their consultant, Trinity Consultants, dated May 21, 2020, and submitted via email to Stephen Ours as an application supplement on March 11, 2022.

value of the fuel fired and which commenced construction, modification, or reconstruction after October 3, 1977. Both Combustion Turbines 1 and 2 are subject to this subpart because each are rated 58 MMBtu/hr based on the lower heating value of natural gas. In addition, the construction of these combustion turbines occurred on May 20, 2002, which is after October 3, 1977 but prior to the applicability date of NSPS Subpart KKKK, which is February 18, 2005. All the requirements of this regulation that apply to the units are stipulated in the permit.

40 CFR 63, Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters:
Pursuant to 40 CFR 63.7485, 63.7490 and 63.7575, NESHAP Subpart DDDDD applies to new and existing industrial commercial or institutional boilers at major sources of Hazardous Air Pollutants (HAPs). GSA is a major source of HAPs for hexane. Therefore Subpart DDDDD does apply.

Under this regulation, the cogeneration system meets the definition of a "Unit designed to burn gas 1 subcategory" unit. This is defined as follows [40 CFR 63.7575]:

"Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition."

This equipment, including both combustion turbines and the duct burners, burn natural gas as their primary fuel. The duct burners burn natural gas exclusively, whereas the combustion turbines burn liquid fuel (No. 2 fuel oil) in accordance with the limitations in this definition.

The equipment is considered to be "existing" equipment per 40 CFR 63.7490 as it was constructed/reconstructed most recently before June 4, 2010.

Pursuant to 40 CFR 63.7500(e), this equipment is not subject to the emission limits in Tables 1 and 2 or 11 through 13 of Subpart DDDDD, nor are they subject to the operating limits in Table 4 of the subpart. As such, per 40 CFR 63.7500(a), the only emission limitations, work practice standards, and operating limits applicable to the equipment under this regulation are the work practice standards of Table 3 of the regulation and the general duty clause in 40 CFR 63.7500(a)(3). This includes annual tune-ups as specified in 40 CFR 63.7540 and a one-time energy assessment performed by a qualified energy assessor.

The requirement to perform a one-time energy assessment has not been included in the permit as it was previously performed on January 28, 2016. A report of this assessment has been submitted to the Department.

All the requirements of this regulation are specified in the permit. The tune-up requirements found in 40 CFR 63.7540(a)(10) are streamlined with 20 DCMR 805 combustion adjustment requirements and are incorporated into Conditions III(f) and V(l). The general duty clause of 40 CFR 63.7500(a)(3) is incorporated into Condition III(g).

40 CFR 63, Subpart JJJJJJ: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources:
NESHAP Subpart JJJJJJ applies to new, reconstructed, or existing industrial commercial or institutional boilers that are not exempt pursuant to 40 CFR 63.11195 and are located at or are part of an area source of HAPs. GSA is a major source of HAPs, rather than an area source, and thus is not subject to this rule.

40 CFR 75 – Continuous Emission Monitoring:
Pursuant to 40 CFR 75.2(c), “the provisions of this part apply to sources subject to a State or federal NOx mass emission reduction program, to the extent these provisions are adopted as requirements under such a program.” This applies because 20 DCMR Chapter 10, the District’s “Nitrogen Oxides Emissions Budget Program”, is considered a NOx mass emission reduction program and in 20 DCMR 1002.1, requires that the facility comply with the CEMS provisions of 40 CFR 75, Subpart H. It should be noted that 40 CFR 75, Subpart H, incorporates other portions of 40 CFR 75 by reference. These requirements have been incorporated throughout the permit. Note that this facility is not subject to the District’s Acid Rain program, thus many portions of 40 CFR 75 (especially those related to sulfur dioxide) are not applicable. Portions of 40 CFR 75 that are applicable to an “affected unit” or “group of units monitored at a common stack” do not typically apply as the cogen system is not an affected unit under 40 CFR 75. Some have been retained in the permit where they appear relevant, but in other cases, are not included where they are clearly not relevant. Many of the reporting requirements to EPA have not been incorporated since reporting to EPA is not required under 20 DCMR Chapter 10. Also note that GSA does not use a flow meter to determine exhaust gas flow, but rather converts NOx concentrations to mass emissions with the use of fuel usage monitoring and an F-factor consistent with 40 CFR 75, Appendix F procedures.

RECOMMENDATIONS

The proposed project and attached permit comply with all applicable federal and District air pollution control laws and regulations.

The permit action for the equipment will be published in the DC Register and on DOEE’s website on July 22, 2022. Public comments for the permit action will be solicited from July 22, 2022 through August 22, 2022. AQD will resolve any comments received before taking final action on the applications. If no comments are received, I recommend that permit No. 5197-R1 be issued in accordance with 20 DCMR 200.2 promptly following the end of the public comment period.

ATH/SSO