DEPARTMENT OF THE NAVY
NAVAL SURFACE WARFARE CENTER
PHILADELPHIA DIVISION
5001 SOUTH BROAD STREET
PHILADELPHIA PA 19112-1403

IN REPLY REFER TO:
5090
Ser 102/065
16 Dec 2022

Mr. Edward Wiener
Air Management Services - Source Registration
321 University Avenue, 2nd Floor
Philadelphia, PA 19104-4543

Dear Mr. Wiener:

SUBJECT: RACT III INITIAL NOTIFICATION AND ALTERNATIVE CASE-BY-CASE PLAN APPROVAL APPLICATION

The purpose of this letter is to submit an initial notification and alternative case-by-case plan approval application for sources located at Naval Surface Warfare Center, Philadelphia Division (NSWCPD) (PLID 09724) that are subject to the final-form rulemaking entitled "Additional RACT Requirements for Major Sources of NOx and VOCs for the 2015 Ozone NAAQS (RACT III)" under 25 Pa. Code Chapters 121 and 129. The initial notification, which includes supporting documentation required under §129.111(a), §129.111(c), and §129.112, is included as enclosure (1). The plan approval application, which is required by §129.114 for alternative RACT proposals, is included as enclosure (2). The Compliance Review Form, which is required for a complete plan approval application, is also included as enclosure (2).

Questions regarding this matter may be directed to Ms. Jennifer Stager at (215) 897-2241 or email jennifer.l.stager.civ@us.navy.mil.

Sincerely,

SIMON.DANA.FRANCIS.1179629174 Digitally signed by SIMON.DANA.FRANCIS.1179629174 Date: 2022.12.16 13:29:46 -05'00'

DANA F. SIMON
Captain, U.S. Navy
Commanding Officer

Enclosure: 1. Initial Notification
2. Plan Approval Application and Compliance Review Form

RACT III Initial Notification

Table of Contents

List of Tables

List of Attachments

Section 1 – RACT III Initial Notification Summary

Pursuant to §129.115(a), NSWCPD is submitting a notification to Philadelphia Air Management Services (AMS) to propose how the facility intends to comply with the requirements of §§129.111-129.114. In accordance with §129.115(a)(1)(i), NSWCPD must submit the notification no later than December 31, 2022 to satisfy compliance requirements. Failure to meet this deadline could result in notices of violations and/or other enforcement actions. The facility wide potential-to-emit (PTE) is 950.80 tons per year (TPY) for NOx and 22.70 TPY for VOC. See Attachment A for supporting calculations. Facility Nitrogen Oxides (NOx) emissions are limited to a Plantwide Applicability Limitation (PAL) of 240.4 tons per rolling 12-month period in accordance with PAL Permit No. 14347 issued July 10, 2019. NSWCPD currently meets the definition of a major NOx emitting facility as the PTE is over 100 TPY.

Sections 2, 3, and 4 outline the RACT requirements, with information identifying the following:

- Sources subject to presumptive requirements
    - Combustion sources with a rated heat input of less than 20 MMBtu/hr (Section 2.1.1)
    - Emergency standby engines that operate less than 500 hours per 12-month rolling period (Section 2.1.2)
    - Simple cycle combustion turbines with a rated output between 4,100 bhp and 60,000 bhp (Section 2.1.3)
- Proposed method to demonstrate compliance with each presumptive requirement
- Sources seeking a case-by-case exemption determination from presumptive requirement emission limits
- Sources notified previously under RACT II that can complete a limited analysis under RACT III, in lieu of conducting a full case-by-case exemption determination (Section 2.1.5)
- Sources exempt from presumptive requirements based on individual PTE less than 1 TPY (Section 2.2 and Section 4)

Section 2 - §129.111(a) Source Determination

The following sources are located at a major NOx emitting facility that commenced operation on or before August 3, 2018 and are not subject to §129.111(c), which exempts sources that have the potential to emit less than 1 TPY of NOx emissions. The sources listed in Table 1 include their identification, source specific information (capacity, fuel type), potential emissions, and are marked with their applicable regulatory citation. Sources installed at the facility that are not listed in Table 1 are exempt as discussed in Section 4 and Table 4.

Table 1 - RACT III Applicability Matrix

Source ID	Source Description	Rated Capacity	Fuel	NOx PTE (tpy)	Applicable Regulatory Citation[a]				
					§129.112 (c)(4)	§129.112 (c)(10)	§129.112 (g)(2)(v)	§129.114 (d)(1)	§129.114 (i)
CU-M111	B77H, Engine Testing Gas Turbine DDG-51 (LM2500 2A)	206.9 MMBtu/hr	No. 2 FO	210.11					x
CU-M112	B77H, Engine Testing Gas Turbine DDG-51 (LM2500 2B)	206.9 MMBtu/hr	No. 2 FO	192.86					x
CU-M113	B77H, Engine Testing Gas Turbine CG-47 GTG #3 (K-17)	40.6 MMBtu/hr	No. 2 FO	56.79					x
CU-M114	B77H, Engine Testing Gas Turbine DDG-51 GTG #2 (K-34)	37.4 MMBtu/hr	No. 2 FO	65.11					x
CU-M139	B77H, Engine Testing Gas Turbine DDG-51 GTG#1 (K-34)	37.4 MMBtu/hr	No. 2 FO	56.79					x
CU-M142	B77H, Engine Testing Gas Turbine Auxiliary (RIMSS)	4.72 MMBtu/hr	No. 2 FO	7.17					x
CU-M151	B77H; DD(X) LM-500	51.4 MMBtu/hr	No. 2 FO	72.28					x
CU-B112	B77L, Boiler	8.4 MMBtu/hr	NG	3.51	x				
CU-B113	B77L, Boiler	8.4 MMBtu/hr	NG	3.51	x				
CU-B114	B77H, Boiler	8.4 MMBtu/hr	NG	3.50	x				
CU-B116a	B77H, 4 Make-up Air Heaters	1.2 MMBtu/hr	NG	2.00	x				
CU-GT115	B1000, Emergency Generator	186 HP	NG	1.10		x			
CU-B131	B633, Air Handler	2.5 MMBtu/hr	NG	1.04	x				
CU-M157	B77H (Outside), GTG with water injection system	230.8 MMBtu/hr	NG	117.00			x	x	

[a] Regulatory citations are defined as follows:
- §129.112(c)(4) – Presumptive requirements for combustion sources with a rated heat input of less than 20 MMBtu/hr
- §129.112(c)(10) – Presumptive requirements for emergency standby engines that operate less than 500 hours per 12-month rolling period
- §129.112(g)(2)(v) – Presumptive requirements for simple cycle combustion turbines with a rated output between 4,100 bhp and 60,000 bhp
- §129.114(d)(1) – Sources seeking case-by-case exemption determinations
- §129.114(i) – Sources previously notified under RACT II that are submitting a limited analysis for RACT III

Section 2.1 - Sources Subject to §§129.112-129.114 RACT Requirements

Section 2.1.1 - §129.112(c)(4) Presumptive RACT Requirements for Boilers and Combustion Units

CU-B112, CU-B113, CU-B114, CU-B116a, and CU-B131 are boilers or other combustion sources with an individual rated gross heat input of less than 20 MMBtu/hr and are subject to this presumptive RACT requirement section. To demonstrate compliance, NSWCPD has and will continue to install, maintain and operate the sources in accordance with manufacturer's specifications and with good operating practices.

Section 2.1.2 – §129.112(c)(10) Presumptive RACT Requirements for Emergency Engines

CU-GT115 is an emergency standby engine that operates less than 500 hours per 12-month rolling period and is subject to this presumptive RACT requirement section. To demonstrate compliance, NSWCPD has and will continue to install, maintain and operate the source in accordance with manufacturer's specifications and with good operating practices.

Section 2.1.3 – §129.112(g)(2)(v) Presumptive RACT Requirements for Combustion Turbines

CU-M157 is a simple cycle combustion turbine with a rated output equal to or greater than 4,100 bhp and less than 60,000 bhp. See Section 2.1.4 for further details on ability to comply with the emission limits under §129.112(g)(2)(v)(A) and §129.112(g)(2)(v)(C).

Section 2.1.4 – §129.114(d)(1) Case-by-Case Exemption Determination Alternative Proposal

CU-M157 is a simple cycle gas turbine (GTG) rated at 20 MW (26,840 HP) that operates on natural gas as the primary fuel and No. 2 fuel oil when natural gas is unavailable, including instances of curtailment by the utility and mechanical issues with the electric natural gas booster pump or other system components. The GTG supplies power to the Compatibility Test Facility (CTF) which is used to support research and development testing for shipboard propulsion and ship service electrical system components. The GTG serves as the primary source of electrical power for the shipboard component testing only. This contingency is necessary to maintain testing during critical periods with minimal interruptions. The GTG is equipped with a water injection system to control NOx emissions.

Table 2 – CU-M157 Emission Limits with Water Injection (>75% Load)

Fuel	Emission Limits (ppm @ 15% O2)		Stack Test Results from January 2022 (ppm @ 15% O2)
	§129.112(g)(2)(v)	IP18-000235 and 40 CFR §60.4330(a)(1)	15 MW w/ Water Injection
Natural Gas	42	25	24.5
Fuel Oil	96	74	38.3

The presumptive RACT III emission limitations under §129.112(g)(2)(v) apply to the GTG, listed in Table 2. When operating the GTG above 5 MW using water injection, stack test results demonstrate compliance with the aforementioned emission limits (see Table 2 above). NSWCPD will continue to conduct performance tests in accordance with IP18-000235, which will in turn demonstrate compliance with the less stringent presumptive RACT NOx emission limits.

Table 3 – CU-M157 Emission Limits without Water Injection (<75% Load)

Fuel	Emission Limits (ppm @ 15% O2)		Stack Test Results from January 2022 (ppm @ 15% O2)
	§129.112(g)(2)(v)	IP18-000235 and 40 CFR §60.4330(a)(1)	5 MW w/o Water Injection
Natural Gas	42	150	74.7
Fuel Oil	96	150	120.9

The GTG does not run continuously, and operations are typically intermittent and at varying loads, which are categorized as low load (<5 MW) and high load (>5 MW). Operations are dependent upon testing schedules and will vary in peak load and duration. Per condition 11(b) of IP18-000235 and draft permit IP21-000322, the GTG can operate without water injection at low load. When operating the GTG at low load without water injection, stack test results demonstrate compliance with permitted emission limits of 40 CFR 60 Subpart KKKK Table 1, but the GTG at low load will not meet the more stringent RACT NOx emission limits (see Table 3 above).

NSWCPD has analyzed the option of operating water injection at low loads, and determined that it would be technically infeasible for the GTG. The manufacturer's recommended operating procedure [see Attachment B under Enclosure (2)] states that the water injection system cannot be used below 5 MW due to the high risk of engine blow out and lowered airflow resulting in poor atomization of the water, inefficient NOx control, and accelerated distress of the combustion system due to water erosion. This is also captured in 40 CFR 60 Subpart KKKK Table 1 for turbines operating at less than 75% of peak load, which requires compliance with the less stringent NOx emission limit of 150 ppm.

NSWCPD has also analyzed the option of including additional controls during operation without water injection, all of which were determined to be technically and economically infeasible. In the original plan approval application for the GTG (dated January 2015), NSWCPD reviewed the technical and economic feasibility for other emission controls before deciding on water injection. See Attachment C under Enclosure (2) for the full control technology review narrative included with the application.

- Selective Catalytic Reduction (SCR) – Due to rapid and frequent changes in engine output, the variations in exhaust temperature, flow rate, and NOx emissions from the CTF would place demands on the SCR controller not found in commercial SCR systems. The addition of an SCR would not allow testing to completely simulate shipboard operations or meet testing objectives. The economic cost is approximately $22,700 to $27,500 per ton of NOx which is not economically viable for NWSCPD.
- Selective Non-Catalytic Reduction (SNCR) – Similar to SCR, due to rapid and frequent changes in adding SNCR would invalidate test results and disrupt operating conditions of the test cell.
- Dry Low Emissions (DLE) Combustion – With frequent and rapid changes to engine output, the risk of engine blowout increases, further reducing NOx control efficiency. Adding DLE would also require a redesign of the gas turbine module and combustor, which would impact NSWCPD's ability to test propulsion and ship service systems at CTF (increasing risk and cost).

Per §129.114(d)(2), NSWCPD is submitting a case-by-case alternative RACT proposal through a plan approval. The plan approval application with attachments and compliance review form are included as Enclosure (2).

Section 2.1.5 - §129.114(i) – RACT II Limited Analysis

CU-M111, CU-M112, CU-M113, CU-M114, CU-M139, CU-M142, and CU-M151 were previously subject to RACT II case-by-case determinations, as approved by AMS under IP16-000235, dated 3/20/20 (see Attachment B). The sources listed here have not been modified since RACT II, the previously analyzed emission controls remain technically infeasible, and they do not qualify for any additional presumptive requirements under RACT III. NSWCPD is submitting this limited analysis in lieu of another full case-by-case proposal. The signature on the notification cover letter serves as the responsible official certification for the limited analysis under §129.114(i) for sources previously subject to RACT II case-by-case determinations.

CU-M111, CU-M112, CU-M113, CU-M114, CU-M139, CU-M142, and CU-M151 are simple cycle marine gas turbine engines that operate on #2 diesel or JP-5 fuel oil. The purpose of this equipment is to act as full scale test sites which house a variety of marine engines used for the research, development, test and evaluation of ship propulsion and power generation systems. RACT II NOx requirements were evaluated on a case-by case basis in accordance with §129.99(a). Possible NOx controls for simple cycle gas turbines in descending order of control effectiveness include SCR, SNCR, DLE, water injection, and fuel switch to natural gas.

Analysis of all options has shown that they would be technically infeasible for NSWCPD's applications. These test facilities are used to evaluate equipment under shipboard conditions in an at-sea environment and therefore must be configured exactly as they are on a ship. There is currently no emission control equipment approved for or installed on a Navy ship. Additionally, all existing shipboard equipment is operated on liquid fuel oil only. The implementation of any of the above control devices would invalidate test results and are therefore not technically feasible. It should also be noted that operations are not typical of similar equipment used in industry. Being a research facility, operations are historically intermittent and are driven by test schedules dictated by Navy sponsors. It is therefore necessary to maintain a high potential to emit (PTE) to accommodate the irregular spikes in operations due to unanticipated changes in testing protocols.

Section 2.2 - Sources Exempt from §§129.112-129.114 per §129.111(c)

Each of the following sources have a PTE of less than 1 TPY of NOx and are exempt from §§129.112-129.114 per §129.111(c). Individual source PTE NOx emissions are shown in the table below. See Attachment A for supporting calculations.

Table 4 – Sources with PTE < 1 TPY

Source ID	Source Description	Rated Capacity		Fuel	NOx PTE (tpy)
CU-B116b [a]	B77H, 6 Unit Heaters	0.3	MMBtu/hr	Natural Gas	0.75
CU-B120a [a]	B633, Boiler 1	0.75	MMBtu/hr	Natural Gas	0.31
CU-B120b [a]	B633, Boiler 2	0.75	MMBtu/hr	Natural Gas	0.31
CU-GT109 [a]	B4, Emergency Generator G1	88	HP	Natural Gas	0.50
CU-GT110 [a]	B4, Emergency Generator G2	154	HP	Natural Gas	0.87
CU-GT113 [a]	B29, Emergency Generator	54	HP	Natural Gas	0.29
CU-M146 [a]	B485,North Fire Pump	208	HP	Diesel	0.31
CU-M147 [a]	B485, South Fire Pump	208	HP	Diesel	0.31
CU-M156 [a]	B542, Fire Pump	115	HP	Diesel	0.31
CU-B121a	B4, Boiler 1	2	MMBtu/hr	Natural Gas	0.43
CU-B121b	B4, Boiler 2	2	MMBtu/hr	Natural Gas	0.43
CU-B121c	B4, Boiler 3	2	MMBtu/hr	Natural Gas	0.43
CU-B121d	B4, Boiler 4	2	MMBtu/hr	Natural Gas	0.43
CU-B122a	B29, Boiler 1	2	MMBtu/hr	Natural Gas	0.43
CU-B122b	B29, Boiler 2	2	MMBtu/hr	Natural Gas	0.43
CU-B123a	B1000, Boiler 1	2	MMBtu/hr	Natural Gas	0.43
CU-B123b	B1000, Boiler 2	2	MMBtu/hr	Natural Gas	0.43
CU-B123c	B1000, Boiler 3	2	MMBtu/hr	Natural Gas	0.43
CU-B123d	B1000, Boiler 4	2	MMBtu/hr	Natural Gas	0.43
CU-B130	B633, Boiler	0.4	MMBtu/hr	Natural Gas	0.17
CU-B132	B633, HVAC Unit	0.8	MMBtu/hr	Natural Gas	0.33
CU-B133	B633, Warm Air Furnace	0.35	MMBtu/hr	Natural Gas	0.15
CU-B135	B77H, GTG Anti-Icing Boiler	8.57	MMBtu/hr	Natural Gas	0.89

[a] Sources were previously notified for RACT II as subject to presumptive requirements under §129.93(c). To be consistent with the applicability language in §129.111(a), these sources will now be subject to §129.111(c) instead for the purposes of the RACT III notification. Regardless, NSWCPD will continue to install, maintain, and operate these sources in accordance with manufacturer's specifications and with good operating practices.

Section 3 - §129.111(b) Source Determination

There are no sources applicable to §129.111(b) as NWSCPD is not a major source of VOC with a PTE less than 50 TPY.

Section 4 - §129.111(c) Source Determination

See Section 2.2 - Sources Exempt from §§129.112-129.114 per §129.111(c).

Section 5 – Sources Removed from Facility

The following sources that were previously included in the RACT II notification have been removed from service and are not subject to the RACT III notification.

Table 5 – Inactive or Removed Sources

Source ID	Source Description	Rated Capacity		Fuel
CU-M119	B77H, Diesel Engine Testing, South Test Cell ETF-40B	42.1	MMBtu/hr	No. 2 FO
CU-M149	B633; P-104 Test Cell	238	MMBtu/hr	No. 2 FO
CU-M150	B77H; DD(X) MT-30	311.8	MMBtu/hr	No. 2 FO
CU-M152	B77H; DD(X) RR-4500	55.6	MMBtu/hr	No. 2 FO
CU-M-110G	B77H, Marine Engine Test Cell 1	16.42	MMBtu/hr	No. 2 FO
CU-M144	B87, Engine Testing Diesel Generator	377	HP	No. 2 FO

Attachment A – Potential-to Emit Calculations

NSWCPD (FACILITY ID 9724) POTENTIAL TO EMIT

POINT ID (Sub Facility)	SCC #	DESCRIPTION	POLLUTANT	EMISSION FACTOR (1) (2) (3)	UNITS	ANNUAL USAGE	UNITS	ANNUAL EMISSIONS (5) LBS	TONS	COMMENTS
3	20400302	Bldg 77H, DDG-51	NOx	1.07E+00	LB/MMBTU	2,800,000	GAL	4.20E+05	2.10E+02	EF Stack Test April 2012
(PROC03)		Gas turbine LM-2500-2A	CO	3.30E-03		2,800,000		1.29E+03	6.47E-01	AP-42, Table 3.1-1
		CU-M111	SO2	1.52E-03		2,800,000		5.94E+02	2.97E-01	AP-42, Table 3.1-2a (See Note 2)
		Permit limit: 2,800,000	VOC	4.10E-04		2,800,000		1.61E+02	8.04E-02	AP-42, Table 3.1-2a
			PM2.5	1.20E-02		2,800,000		4.70E+03	2.35E+00	AP-42, Table 3.1-2a (See Note 3)
			PM10	1.20E-02		2,800,000		4.70E+03	2.35E+00	"
			PM-CON	7.20E-03		2,800,000		2.82E+03	1.41E+00	"
			BENZENE	5.50E-05		2,800,000		2.16E+01	1.08E-02	AP-42, Table 3.1-4
			FORMALDEHYDE	2.80E-04		2,800,000		1.10E+02	5.49E-02	"
			NAPHTHALENE	3.50E-05		2,800,000		1.37E+01	6.86E-03	"
			TOTAL PAH	4.00E-05		2,800,000		1.57E+01	7.84E-03	"
			CADMIUM	4.80E-06		2,800,000		1.88E+00	9.41E-04	AP-42, Table 3.1-5
			CHROMIUM	1.10E-05		2,800,000		4.31E+00	2.16E-03	"
			LEAD	1.40E-05		2,800,000		5.49E+00	2.74E-03	"
			MANGANESE	7.90E-04		2,800,000		3.10E+02	1.55E-01	"
			MERCURY	1.20E-06		2,800,000		4.70E-01	2.35E-04	"
			CO2	1.02E+01	KG/GAL	2,800,000			3.14E+04	EPA GHG Emission Factors
			CH4	4.10E-01	G/GAL	2,800,000			1.26E+00	"
			N2O	8.00E-02		2,800,000			2.46E-01	"
4	20400302	Bldg 824	NOx	8.80E-01	LB/MMBTU	0	GAL	0.00E+00	0.00E+00	AP-42, Table 3.1-1
(PROC04)		Gas Turbine ETF-40	CO	3.30E-03		0		0.00E+00	0.00E+00	AP-42, Table 3.1-1
		CU-M119	SO2	1.52E-03		0		0.00E+00	0.00E+00	AP-42, Table 3.1-2a (See Note 2)
		Permit limit: 250,000	VOC	4.10E-04		0		0.00E+00	0.00E+00	AP-42, Table 3.1-2a
		SOURCE REMOVED	PM2.5	1.20E-02		0		0.00E+00	0.00E+00	AP-42, Table 3.1-2a (See Note 3)
			PM10	1.20E-02		0		0.00E+00	0.00E+00	"
			PM-CON	7.20E-03		0		0.00E+00	0.00E+00	"
			BENZENE	5.50E-05		0		0.00E+00	0.00E+00	AP-42, Table 3.1-4
			FORMALDEHYDE	2.80E-04		0		0.00E+00	0.00E+00	"
			NAPHTHALENE	3.50E-05		0		0.00E+00	0.00E+00	"
			TOTAL PAH	4.00E-05		0		0.00E+00	0.00E+00	"
			CADMIUM	4.80E-06		0		0.00E+00	0.00E+00	AP-42, Table 3.1-5
			CHROMIUM	1.10E-05		0		0.00E+00	0.00E+00	"
			LEAD	1.40E-05		0		0.00E+00	0.00E+00	"
			MANGANESE	7.90E-04		0		0.00E+00	0.00E+00	"
			MERCURY	1.20E-06		0		0.00E+00	0.00E+00	"
			CO2	1.02E+01	KG/GAL	0			0.00E+00	EPA GHG Emission Factors
			CH4	4.10E-01	G/GAL	0			0.00E+00	"
			N2O	8.00E-02		0			0.00E+00	"
5	20400302	Bldg 77H	NOx	6.49E-01	LB/MMBTU	1,250,000	GAL	1.14E+05	5.68E+01	EF Stack Test November 2012
(PROC05)		K17 Allison Gas Turbine	CO	3.30E-03		1,250,000		5.78E+02	2.89E-01	AP-42, Table 3.1-1
		Generator #3	SO2	1.52E-03		1,250,000		2.65E+02	1.33E-01	AP-42, Table 3.1-2a (See Note 2)
		CU-M113	VOC	4.10E-04		1,250,000		7.18E+01	3.59E-02	AP-42, Table 3.1-2a
		Permit limit: 1,250,000	PM2.5	1.20E-02		1,250,000		2.10E+03	1.05E+00	AP-42, Table 3.1-2a (See Note 3)
			PM10	1.20E-02		1,250,000		2.10E+03	1.05E+00	"
			PM-CON	7.20E-03		1,250,000		1.26E+03	6.30E-01	"
			BENZENE	5.50E-05		1,250,000		9.63E+00	4.81E-03	AP-42, Table 3.1-4
			FORMALDEHYDE	2.80E-04		1,250,000		4.90E+01	2.45E-02	"
			NAPHTHALENE	3.50E-05		1,250,000		6.13E+00	3.06E-03	"
			TOTAL PAH	4.00E-05		1,250,000		7.00E+00	3.50E-03	"
			CADMIUM	4.80E-06		1,250,000		8.40E-01	4.20E-04	AP-42, Table 3.1-5
			CHROMIUM	1.10E-05		1,250,000		1.93E+00	9.63E-04	"
			LEAD	1.40E-05		1,250,000		2.45E+00	1.23E-03	"
			MANGANESE	7.90E-04		1,250,000		1.38E+02	6.913E-02	"
			MERCURY	1.20E-06		1,250,000		2.10E-01	1.050E-04	"
			CO2	1.02E+01	KG/GAL	1,250,000			1.40E+04	EPA GHG Emission Factors
			CH4	4.10E-01	G/GAL	1,250,000			5.64E-01	"
			N2O	8.00E-02		1,250,000			1.10E-01	"
6	20400302	Bldg 77H	NOx	7.95E-01	LB/MMBTU	1,170,000	GAL	1.30E+05	6.51E+01	EF Stack Test April 2012
(PROC22)		K34 Allison Gas Turbine	CO	3.30E-03		1,170,000		5.41E+02	2.70E-01	AP-42, Table 3.1-1

NSWCPD (FACILITY ID 9724) POTENTIAL TO EMIT

POINT ID (Sub Facility)	SCC #	DESCRIPTION	POLLUTANT	EMISSION FACTOR (1)(2)(3)	UNITS	ANNUAL USAGE	UNITS	ANNUAL EMISSIONS (5) LBS	TONS	COMMENTS
		CU-M114 (GTG#2)	SO2	1.52E-03		1,170,000		2.48E+02	1.24E-01	AP-42, Table 3.1-2a (See Note 2)
		Permit limit: 1,170,000	VOC	4.10E-04		1,170,000		6.72E+01	3.36E-02	AP-42, Table 3.1-2a
			PM2.5	1.20E-02		1,170,000		1.97E+03	9.83E-01	AP-42, Table 3.1-2a (See Note 3)
			PM10	1.20E-02		1,170,000		1.97E+03	9.83E-01	"
			PM-CON	7.20E-03		1,170,000		1.18E+03	5.90E-01	"
			BENZENE	5.50E-05		1,170,000		9.01E+00	4.50E-03	AP-42, Table 3.1-4
			FORMALDEHYDE	2.80E-04		1,170,000		4.59E+01	2.29E-02	"
			NAPHTHALENE	3.50E-05		1,170,000		5.73E+00	2.87E-03	"
			TOTAL PAH	4.00E-05		1,170,000		6.55E+00	3.28E-03	"
			CADMIUM	4.80E-06		1,170,000		7.86E-01	3.93E-04	AP-42, Table 3.1-5
			CHROMIUM	1.10E-05		1,170,000		1.80E+00	9.01E-04	"
			LEAD	1.40E-05		1,170,000		2.29E+00	1.15E-03	"
			MANGANESE	7.90E-04		1,170,000		1.29E+02	6.47E-02	"
			MERCURY	1.20E-06		1,170,000		1.97E-01	9.83E-05	"
			CO2	1.02E+01	KG/GAL	1,170,000			1.31E+04	EPA GHG Emission Factors
			CH4	4.10E-01	G/GAL	1,170,000			5.28E-01	"
			N2O	8.00E-02		1,170,000			1.03E-01	"
8	20100202	Bldg 4, 4th Floor	NOx	2.84E+03	LB/10^6 SCF	0.963	10^6 SCF	2.73E+03	1.37E+00	EPA webFire database
(PROC08)		N.G. Emergency Generators	VOC	1.16E+02		0.963		1.12E+02	5.58E-02	"
		GT109/GT110	CO	3.99E+02		0.963		3.84E+02	1.92E-01	"
		500 hours each	SO2	6.00E-01		0.963		5.78E-01	2.89E-04	"
		GT109=748 cuft/hr	PM10	2.01E+01		0.963		1.94E+01	9.68E-03	"
		GT110=1177 cuft/hr	PM2.5	2.01E+01		0.963		1.94E+01	9.68E-03	"
		748*500= 374000 cuft	PM-CON	1.01E+01		0.963		9.73E+00	4.87E-03	"
		1177*500 = 588500 cuft	CO2	5.45E-02	KG/SCF	0.963			5.77E+01	EPA GHG Emission Factors
		total: 962500 cuft (0.9625 mmcf)	CH4	1.03E-03	G/SCF	0.963			1.09E-03	"
			N2O	1.03E-04		0.963			1.09E-04	"
9	10500206	Bldg 87	NOx	1.00E+02	LB/10^6 SCF	61.28	10^6 SCF	6.13E+03	3.06E+00	EPA webFire database
(COMB09)		(81) N.G. Space Heaters	VOC	5.30E+00		61.28		3.25E+02	1.62E-01	"
		CU-B115	CO	2.00E+01		61.28		1.23E+03	6.13E-01	"
			SO2	6.00E-01		61.28		3.68E+01	1.84E-02	"
		8760 hours	PM10	8.70E+00		61.28		5.33E+02	2.67E-01	"
		71 at 80,000 BTU/hr each	PM2.5	8.70E+00		61.28		5.33E+02	2.67E-01	"
		17 at 60,000 BTU/hr each	PM-CON	5.70E+00		61.28		3.49E+02	1.75E-01	"
		11 at 45,000 BTU/hr each	LEAD	5.00E-04		61.28		3.06E-02	1.53E-05	AP-42, Table 1.4-2
		5 at 30,000 BTU/hr each	ARSENIC	2.00E-04		61.28		1.23E-02	6.13E-06	AP-42, Table 1.4-4
		7345000	CADMIUM	1.10E-03		61.28		6.74E-02	3.37E-05	"
		7.345MMBtu/hr/1050MMBTU/MMCF	CHROMIUM	1.40E-03		61.28		8.58E-02	4.29E-05	"
		0.006995238	COBALT	8.40E-05		61.28		5.15E-03	2.57E-06	"
		0.00699MMCF/hr * 8760hrs =	MANGANESE	3.80E-04		61.28		2.33E-02	1.16E-05	"
		61.27828571	MERCURY	2.60E-04		61.28		1.59E-02	7.97E-06	"
		MMCF	NICKEL	2.10E-03		61.28		1.29E-01	6.43E-05	"
			2-METHYLNAPHTHALENE	2.40E-05		61.28		1.47E-03	7.35E-07	AP-42, Table 1.4-3
			BENZENE	2.10E-03		61.28		1.29E-01	6.43E-05	AP-42, Table 1.4-3
			DICHLOROBENZENE	1.20E-03		61.28		7.35E-02	3.68E-05	"
			FLUORANTHENE	3.00E-06		61.28		1.84E-04	9.19E-08	"
			FLOURENE	2.80E-06		61.28		1.72E-04	8.58E-08	"
			FORMALDEHYDE	7.50E-02		61.28		4.60E+00	2.30E-03	"
			HEXANE	1.80E+00		61.28		1.10E+02	5.52E-02	"
			NAPHTHALENE	6.10E-04		61.28		3.74E-02	1.87E-05	"
			PHENANTHRENE	1.70E-05		61.28		1.04E-03	5.21E-07	"
			PYRENE	5.00E-06		61.28		3.06E-04	1.53E-07	"
			TOLUENE	3.40E-03		61.28		2.08E-01	1.04E-04	"
			CO2	5.45E-02	KG/SCF	61.28			3.67E+03	EPA GHG Emission Factors
			CH4	1.03E-03	G/SCF	61.28			6.93E-02	"
			N2O	1.03E-04		61.28			6.94E-03	"
17	20400302	Bldg 77H	NOx	9.84E-01	LB/MMBTU	2,800,000	GAL	3.86E+05	1.93E+02	EF Stack Test April 2012
(PROC17)		DDG-51 Gas Turbine	CO	3.30E-03		2,800,000		1.29E+03	6.47E-01	AP-42, Table 3.1-1
		LM-2500-2B	SO2	1.52E-03		2,800,000		5.94E+02	2.97E-01	AP-42, Table 3.1-2a (See Note 2)

NSWCPD (FACILITY ID 9724) POTENTIAL TO EMIT

POINT ID (Sub Facility)	SCC #	DESCRIPTION	POLLUTANT	EMISSION FACTOR (1)(2)(3)	UNITS	ANNUAL USAGE	UNITS	ANNUAL EMISSIONS (5) LBS	TONS	COMMENTS
		CU-M112	VOC	4.10E-04		2,800,000		1.61E+02	8.04E-02	AP-42, Table 3.1-2a
		Permit limit: 2,800,000	PM2.5	1.20E-02		2,800,000		4.70E+03	2.35E+00	AP-42, Table 3.1-2a (See Note 3)
			PM10	1.20E-02		2,800,000		4.70E+03	2.35E+00	"
			PM-CON	7.20E-03		2,800,000		2.82E+03	1.41E+00	"
			BENZENE	5.50E-05		2,800,000		2.16E+01	1.08E-02	AP-42, Table 3.1-4
			FORMALDEHYDE	2.80E-04		2,800,000		1.10E+02	5.49E-02	"
			NAPHTHALENE	3.50E-05		2,800,000		1.37E+01	6.86E-03	"
			TOTAL PAH	4.00E-05		2,800,000		1.57E+01	7.84E-03	"
			CADMIUM	4.80E-06		2,800,000		1.88E+00	9.41E-04	AP-42, Table 3.1-5
			CHROMIUM	1.10E-05		2,800,000		4.31E+00	2.16E-03	"
			LEAD	1.40E-05		2,800,000		5.49E+00	2.74E-03	"
			MANGANESE	7.90E-04		2,800,000		3.10E+02	1.55E-01	"
			MERCURY	1.20E-06		2,800,000		4.70E-01	2.35E-04	"
			CO2	1.02E+01	KG/GAL	2,800,000			3.14E+04	EPA GHG Emission Factors
			CH4	4.10E-01	G/GAL	2,800,000			1.26E+00	"
			N2O	8.00E-02		2,800,000			2.46E-01	"
19	10300603	Bldg 77L Heating Boilers	NOx	1.00E+02	LB/10^6 SCF	140.16	10^6 SCF	1.40E+04	7.01E+00	AP-42, Table 1.4-1
(COMB19)		Natural Gas	CO	8.40E+01		140.16		1.18E+04	5.89E+00	"
		CU-B112/B113	LEAD	5.00E-04		140.16		7.01E-02	3.50E-05	AP-42, Table 1.4-2
		8760	PM10	7.60E+00		140.16		1.07E+03	5.33E-01	"
		CU-B112 (8.4 MMBTU/hr)	PM2.5	7.60E+00		140.16		1.07E+03	5.33E-01	"
		CU-B113 (8.4 MMBTU/hr)	PM-CON	5.70E+00		140.16		7.99E+02	3.99E-01	"
		(8.4/1050*8760)*2 =	SO2	6.00E-01		140.16		8.41E+01	4.20E-02	"
		140.16	VOC	5.50E+00		140.16		7.71E+02	3.85E-01	"
		MMCF	AMMONIA	4.90E-01		140.16		6.87E+01	3.43E-02	EPA webFire Database
			2-METHYLNAPHTHALENE	2.40E-05		140.16		3.36E-03	1.68E-06	AP-42, Table 1.4-3
			BENZENE	2.10E-03		140.16		2.94E-01	1.47E-04	"
			DICHLOROBENZENE	1.20E-03		140.16		1.68E-01	8.41E-05	"
			FLUORANTHENE	3.00E-06		140.16		4.20E-04	2.10E-07	"
			FLOURENE	2.80E-06		140.16		3.92E-04	1.96E-07	"
			FORMALDEHYDE	7.50E-02		140.16		1.05E+01	5.26E-03	"
			HEXANE	1.80E+00		140.16		2.52E+02	1.26E-01	"
			NAPHTHALENE	6.10E-04		140.16		8.55E-02	4.27E-05	"
			PHENANTHRENE	1.70E-05		140.16		2.38E-03	1.19E-06	"
			PYRENE	5.00E-06		140.16		7.01E-04	3.50E-07	"
			TOLUENE	3.40E-03		140.16		4.77E-01	2.38E-04	"
			ARSENIC	2.00E-04		140.16		2.80E-02	1.40E-05	AP-42, Table 1.4-4
			CADMIUM	1.10E-03		140.16		1.54E-01	7.71E-05	"
			CHROMIUM	1.40E-03		140.16		1.96E-01	9.81E-05	"
			COBALT	8.40E-05		140.16		1.18E-02	5.89E-06	"
			MANGANESE	3.80E-04		140.16		5.33E-02	2.66E-05	"
			MERCURY	2.60E-04		140.16		3.64E-02	1.82E-05	"
			NICKEL	2.10E-03		140.16		2.94E-01	1.47E-04	"
			CO2	5.45E-02	KG/SCF	140.16			8.40E+03	EPA GHG Emission Factors
			CH4	1.03E-03	G/SCF	140.16			1.58E-01	"
			N2O	1.03E-04		140.16			1.59E-02	"
20	10500106	Bldg 77H	NOx	1.00E+02	LB/10^6 SCF	213.57	10^6 SCF	2.14E+04	1.07E+01	EPA webFire database
(COMB21)		Heating Boiler	VOC	5.30E+00		213.57		1.13E+03	5.66E-01	"
		Unit Heaters	CO	2.00E+01		213.57		4.27E+03	2.14E+00	"
		IR Space Heaters	SO2	6.00E-01		213.57		1.28E+02	6.41E-02	"
		Natural Gas	PM10	8.70E+00		213.57		1.86E+03	9.29E-01	"
		CU-B114/B116/B117	PM2.5	8.70E+00		213.57		1.86E+03	9.29E-01	"
		8760	PM-CON	5.70E+00		213.57		1.22E+03	6.09E-01	"
		CU-B114(8.4 MMBTU/hr)	LEAD	5.00E-04		213.57		1.07E-01	5.34E-05	AP-42, Table 1.4-2
		CU-B116 (6.6 MMBtu/hr)	ARSENIC	2.00E-04		213.57		4.27E-02	2.14E-05	AP-42, Table 1.4-4
		4 @1.2 MMBtu/hr	CADMIUM	1.10E-03		213.57		2.35E-01	1.17E-04	"
		6 @0.3 MMBtu/hr	CHROMIUM	1.40E-03		213.57		2.99E-01	1.49E-04	"
		CU-B117 (10.599 MMBtu/hr)	COBALT	8.40E-05		213.57		1.79E-02	8.97E-06	"
		3 at 150,000 BTU/hr each	MANGANESE	3.80E-04		213.57		8.12E-02	4.06E-05	"
		5 at 175,000 BTU/hr each	MERCURY	2.60E-04		213.57		5.55E-02	2.78E-05	"

NSWCPD (FACILITY ID 9724) POTENTIAL TO EMIT

POINT ID (Sub Facility)	SCC #	DESCRIPTION	POLLUTANT	EMISSION FACTOR (1)(2)(3)	UNITS	ANNUAL USAGE	UNITS	ANNUAL EMISSIONS (5) LBS	TONS	COMMENTS
		67 at 100,000 BTU/hr each	NICKEL	2.10E-03		213.57		4.48E-01	2.24E-04	"
		36 at 71,500 BTU/hr each	2-METHYLNAPHTHALENE	2.40E-05		213.57		5.13E-03	2.56E-06	AP-42, Table 1.4-3
		Total (MMBtu/hr):	BENZENE	2.10E-03		213.57		4.48E-01	2.24E-04	"
		25.599	DICHLOROBENZENE	1.20E-03		213.57		2.56E-01	1.28E-04	"
		Fuel total: (25.599/1050*8760)	FLUORANTHENE	3.00E-06		213.57		6.41E-04	3.20E-07	"
		213.5688	FLOURENE	2.80E-06		213.57		5.98E-04	2.99E-07	"
		MMCF	FORMALDEHYDE	7.50E-02		213.57		1.60E+01	8.01E-03	"
			HEXANE	1.80E+00		213.57		3.84E+02	1.92E-01	"
			NAPHTHALENE	6.10E-04		213.57		1.30E-01	6.51E-05	"
			PHENANTHRENE	1.70E-05		213.57		3.63E-03	1.82E-06	"
			PYRENE	5.00E-06		213.57		1.07E-03	5.34E-07	"
			TOLUENE	3.40E-03		213.57		7.26E-01	3.63E-04	"
			CO2	5.45E-02	KG/SCF	213.57			1.28E+04	EPA GHG Emission Factors
			CH4	1.03E-03	G/SCF	213.57			2.42E-01	"
			N2O	1.03E-04		213.57			2.42E-02	"
21	20400302	Bldg 77H	NOx	7.81E-01	LB/MMBTU	1,170,000	GAL	1.28E+05	6.40E+01	EF Stack Test November 2012
(PROC18)		K34 Allison Gas Turbine	CO	3.30E-03		1,170,000		5.41E+02	2.70E-01	AP-42, Table 3.1-1
		Generator #1	SO2	1.52E-03		1,170,000		2.48E+02	1.24E-01	AP-42, Table 3.1-2a (See Note 2)
		CU-M139, CU-M142	VOC	4.10E-04		1,170,000		6.72E+01	3.36E-02	AP-42, Table 3.1-2a
		Permit limit: 1,170,000	PM2.5	1.20E-02		1,170,000		1.97E+03	9.83E-01	AP-42, Table 3.1-2a (See Note 3)
			PM10	1.20E-02		1,170,000		1.97E+03	9.83E-01	"
			PM-CON	7.20E-03		1,170,000		1.18E+03	5.90E-01	"
			BENZENE	5.50E-05		1,170,000		9.01E+00	4.50E-03	AP-42, Table 3.1-4
			FORMALDEHYDE	2.80E-04		1,170,000		4.59E+01	2.29E-02	"
			NAPHTHALENE	3.50E-05		1,170,000		5.73E+00	2.87E-03	"
			TOTAL PAH	4.00E-05		1,170,000		6.55E+00	3.28E-03	"
			CADMIUM	4.80E-06		1,170,000		7.86E-01	3.93E-04	AP-42, Table 3.1-5
			CHROMIUM	1.10E-05		1,170,000		1.80E+00	9.01E-04	"
			LEAD	1.40E-05		1,170,000		2.29E+00	1.15E-03	"
			MANGANESE	7.90E-04		1,170,000		1.29E+02	6.47E-02	"
			MERCURY	1.20E-06		1,170,000		1.97E-01	9.83E-05	"
			CO2	1.02E+01	KG/GAL	1,170,000			1.31E+04	EPA GHG Emission Factors
			CH4	4.10E-01	G/GAL	1,170,000			5.28E-01	"
			N2O	8.00E-02		1,170,000			1.03E-01	"
26	20100102	Bldg 87 Test Generator	NOx	6.04E+02	LB/10^3 GAL	0	GAL	0.00E+00	0.00E+00	EPA webFire database
(PROC26)		Diesel Generator	CO	1.30E+02		0		0.00E+00	0.00E+00	"
		CU-M144	SOx	3.97E+01		0		0.00E+00	0.00E+00	"
		(North?)	PM10	1.40E+01		0		0.00E+00	0.00E+00	"
		Permit limit: 945 gallons	PM2.5	1.40E+01		0		0.00E+00	0.00E+00	"
			VOC	4.93E+01		0		0.00E+00	0.00E+00	"
		**Note: Source to be removed	BENZENE	1.29E-01		0		0.00.E+00	0.00E+00	"
		Waiting on schedule from test site	TOLUENE	3.86E-02		0		0.00.E+00	0.00E+00	"
		SOURCE REMOVED	XYLENE	6.84E-03		0		0.00.E+00	0.00E+00	"
			FORMALDEHYDE	6.63E-02		0		0.00.E+00	0.00E+00	"
			ETHYLBENZENE	3.07E-03		0		0.00.E+00	0.00E+00	"
			NAPHTHALENE	1.29E-02		0		0.00.E+00	0.00E+00	"
			CO2	1.02E+01	KG/GAL	0			0.00E+00	EPA GHG Emission Factors
			CH4	4.10E-01	G/GAL	0			0.00E+00	"
			N2O	8.00E-02		0			0.00E+00	"
28	20400302	Bldg 77H (6)	NOx			2,716,000	GAL		2.03E+02	DD(X) Test Cell Emission Limit
(PROC41)		DD(X) - Test Cell (Whole Cell)	CO			2,716,000			8.89E+00	"
		MT5S-HE+ 1H	SO2			2,716,000			3.69E+01	"
		CU-M161, CU-M163	VOC			2,716,000			3.12E+00	"
		DD(X) LM500	PM2.5	1.20E-02	LB/MMBTU	2,716,000		4.56E+03	2.28E+00	AP-42, Table 3.1-2a (See Note 3)
		CU-M151	PM10			2,716,000			2.06E+00	DD(X) Test Cell Emission Limit
		MT5S-HE+ 3H	PM-CON	7.20E-03	LB/MMBTU	2,716,000		2.74E+03	1.37E+00	AP-42, Table 3.1-2a (See Note 3)
		CU-M162, CU-M164	BENZENE	5.50E-05		2,716,000		2.09E+01	1.05E-02	AP-42, Table 3.1-4
			FORMALDEHYDE	2.80E-04		2,716,000		1.06E+02	5.32E-02	"

NSWCPD (FACILITY ID 9724) POTENTIAL TO EMIT

POINT ID (Sub Facility)	SCC #	DESCRIPTION	POLLUTANT	EMISSION FACTOR (1)(2)(3)	UNITS	ANNUAL USAGE	UNITS	ANNUAL EMISSIONS (5) LBS	TONS	COMMENTS
			NAPHTHALENE	3.50E-05		2,716,000		1.33E+01	6.65E-03	"
		**Test Cell limits:	TOTAL PAH	4.00E-05		2,716,000		1.52E+01	7.60E-03	"
		Fuel Limit: 2,716,000 gallons	CADMIUM	4.80E-06		2,716,000		1.83E+00	9.13E-04	AP-42, Table 3.1-5
		Emission limits:	CHROMIUM	1.10E-05		2,716,000		4.18E+00	2.09E-03	"
		(ii) NOx - 203.40 tons/rolling 12-month period.	LEAD	1.40E-05		2,716,000		5.32E+00	2.66E-03	"
		(iv) CO - 8.89 tons/rolling 12-month period.	MANGANESE	7.90E-04		2,716,000		3.00E+02	1.50E-01	"
		(vi) SO2 - 36.94 tons/rolling 12-month period.	MERCURY	1.20E-06		2,716,000		4.56E-01	2.28E-04	"
		(vii) PM/PM10 - 2.06 tons/rolling 12-month per	CO2	1.02E+01	KG/GAL	2,716,000			3.05E+04	EPA GHG Emission Factors
		(ix) VOC - 3.12 tons/rolling 12-month period.	CH4	4.10E-01	G/GAL	2,716,000			1.22E+00	"
			N2O	8.00E-02		2,716,000			2.39E-01	"
31	20100202	Bldg 1000	NOx	2.84E+03	LB/10^6 SCF	0.775	10^6 SCF	2.20E+03	1.10E+00	EPA webFire database
(PROC31)		N.G. Emergency Generator	VOC	1.16E+02		0.775		8.99E+01	4.50E-02	"
		CU-GT115	CO	3.99E+02		0.775		3.09E+02	1.55E-01	"
		1550 cuft/hr	SO2	6.00E-01		0.775		4.65E-01	2.33E-04	"
		500 hr limit	PM10	2.01E+01		0.775		1.56E+01	7.79E-03	"
		total: 1550*500 = 775000 cuft (0.775 mmcf)	PM2.5	2.01E+01		0.775		1.56E+01	7.79E-03	"
			PM-CON	1.01E+01		0.775		7.84E+00	3.92E-03	"
			CO2	5.45E-02	KG/SCF	0.775			4.65E+01	EPA GHG Emission Factors
			CH4	1.03E-03	G/SCF	0.775			8.76E-04	"
			N2O	1.03E-04		0.775			8.78E-05	"
32	20200102	Building 485	NOx	6.04E+02	LB/10^3 GAL	2080	GAL	1.26E+03	6.28E-01	EPA webFire database
(PROC32)		Diesel Fire Pumps (N & S)	CO	1.30E+02		2080		2.70E+02	1.35E-01	"
		CU-M146/M147	SOx	3.97E+01		2080		8.26E+01	4.13E-02	"
		10.4 gal/hr each	PM10	4.25E+01		2080		8.84E+01	4.42E-02	"
		100 hr each	PM2.5	4.25E+01		2080		8.84E+01	4.42E-02	"
		m146: 100*10.4 = 1040 gal	VOC	4.93E+01		2080		1.03E+02	5.13E-02	"
		M147: 100*10.4 = 1040 gal	BENZENE	9.33E-04	LB/MMBTU	2080		2.72.E-01	1.36E-04	"
		Total: 2080 gal	TOLUENE	4.09E-04		2080		1.19.E-01	5.96E-05	"
			FORMALDEHYDE	1.18E-03		2080		3.44.E-01	1.72E-04	"
			ACETALDEHYDE	7.67E-04		2080		2.23.E-01	1.12E-04	"
			TOTAL PAH	1.68E-04		2080		4.89.E-02	2.45E-05	"
			ACROLEIN	9.25E-05		2080		2.69.E-02	1.35E-05	"
			XYLENE	2.85E-04		2080		8.30.E-02	4.15E-05	"
			MERCURY	3.01E-07		2080		8.78.E-05	4.39E-08	"
			NAPHTHALENE	8.48E-05		2080		2.47.E-02	1.23E-05	"
			CO2	1.02E+01	KG/GAL	2080			2.34E+01	EPA GHG Emission Factors
			CH4	4.10E-01	G/GAL	2080			9.38E-04	"
			N2O	8.00E-02		2080			1.83E-04	"
33	10300603	Bldg. 633	NOx	1.00E+02	LB/10^6 SCF	12.51	10^6 SCF	1.25E+03	6.26E-01	AP-42, Table 1.4-1
(COMB33)		N.G. Heating Boilers	CO	8.40E+01		12.51		1.05E+03	5.25E-01	"
		CU-B120A/B120B	LEAD	5.00E-04		12.51		6.26E-03	3.13E-06	AP-42, Table 1.4-2
		CU-B120A (0.75 MMBtu/hr)	PM10	7.60E+00		12.51		9.51E+01	4.75E-02	"
		CU-B120B (0.75 MMBtu/hr)	PM2.5	7.60E+00		12.51		9.51E+01	4.75E-02	"
		(0.75/1050*8760)*2	PM-CON	5.70E+00		12.51		7.13E+01	3.57E-02	"
		12.51428571	SO2	6.00E-01		12.51		7.51E+00	3.75E-03	"
		MMCF	VOC	5.50E+00		12.51		6.88E+01	3.44E-02	"
			AMMONIA	4.90E-01		12.51		6.13E+00	3.06E-03	EPA webFire Database
			2-METHYLNAPHTHALENE	2.40E-05		12.51		3.00E-04	1.50E-07	AP-42, Table 1.4-3
			BENZENE	2.10E-03		12.51		2.63E-02	1.31E-05	"
			DICHLOROBENZENE	1.20E-03		12.51		1.50E-02	7.51E-06	"
			FLUORANTHENE	3.00E-06		12.51		3.75E-05	1.88E-08	"
			FLOURENE	2.80E-06		12.51		3.50E-05	1.75E-08	"
			FORMALDEHYDE	7.50E-02		12.51		9.38E-01	4.69E-04	"
			HEXANE	1.80E+00		12.51		2.25E+01	1.13E-02	"
			NAPHTHALENE	6.10E-04		12.51		7.63E-03	3.82E-06	"
			PHENANTHRENE	1.70E-05		12.51		2.13E-04	1.06E-07	"
			PYRENE	5.00E-06		12.51		6.26E-05	3.13E-08	"

NSWCPD (FACILITY ID 9724) POTENTIAL TO EMIT

POINT ID (Sub Facility)	SCC #	DESCRIPTION	POLLUTANT	EMISSION FACTOR (1)(2)(3)	UNITS	ANNUAL USAGE	UNITS	ANNUAL EMISSIONS (5) LBS	TONS	COMMENTS
			TOLUENE	3.40E-03		12.51		4.25E-02	2.13E-05	"
			ARSENIC	2.00E-04		12.51		2.50E-03	1.25E-06	AP-42, Table 1.4-4
			CADMIUM	1.10E-03		12.51		1.38E-02	6.88E-06	"
			CHROMIUM	1.40E-03		12.51		1.75E-02	8.76E-06	"
			COBALT	8.40E-05		12.51		1.05E-03	5.25E-07	"
			MANGANESE	3.80E-04		12.51		4.75E-03	2.38E-06	"
			MERCURY	2.60E-04		12.51		3.25E-03	1.63E-06	"
			NICKEL	2.10E-03		12.51		2.63E-02	1.31E-05	"
			CO2	5.45E-02	KG/SCF	12.51			7.50E+02	EPA GHG Emission Factors
			CH4	1.03E-03	G/SCF	12.51			1.41E-02	"
			N2O	1.03E-04		12.51			1.42E-03	"
34 (PROC34)	20100102	Bldg. 87	NOx	6.04E+02	LB/10^3 GAL	0	GAL	0.00E+00	0.00E+00	EPA webFire database
		Diesel Generator	CO	1.30E+02		0		0.00E+00	0.00E+00	"
		CU-M153	SOx	3.97E+01		0		0.00E+00	0.00E+00	"
		1000hr limit, 6.3 gal/hr	PM10	1.40E+01		0		0.00E+00	0.00E+00	"
		(West)	PM2.5	1.40E+01		0		0.00E+00	0.00E+00	"
		**Note: Source to be removed	VOC	4.93E+01		0		0.00E+00	0.00E+00	"
		Waiting on schedule from test site	BENZENE	1.29E-01		0		0.00.E+00	0.00E+00	"
		SOURCE REMOVED	TOLUENE	3.86E-02		0		0.00.E+00	0.00E+00	"
			XYLENE	6.84E-03		0		0.00.E+00	0.00E+00	"
			FORMALDEHYDE	6.63E-02		0		0.00.E+00	0.00E+00	"
			ETHYLBENZENE	3.07E-03		0		0.00.E+00	0.00E+00	"
			NAPHTHALENE	1.29E-02		0		0.00.E+00	0.00E+00	"
			CO2	1.02E+01	KG/GAL	0			0.00E+00	EPA GHG Emission Factors
			CH4	4.10E-01	G/GAL	0			0.00E+00	"
			N2O	8.00E-02		0			0.00E+00	"
36 (PROC36)	20200102	Bldg. 542	NOx	1.02E+00	LB/MMBTU	4300.0	GAL	6.14E+02	3.07E-01	Manufacturer Emission Data
		Diesel Fire Pump	CO	2.83E-01		4300.0		1.70E+02	8.52E-02	"
		CU-M156	SOx	3.97E+01	LB/10^3 GAL	4300.0		1.71E+02	8.54E-02	EPA webFire database
		500 hr, 8.6 gal/hr	PM10	4.25E+01		4300.0		1.83E+02	9.14E-02	"
		500*8.6 = 4300 gal	PM2.5	4.25E+01		4300.0		1.83E+02	9.14E-02	"
			VOC	1.04E-01	LB/MMBTU	4300.0		6.26E+01	3.13E-02	Manufacturer Emission Data
			BENZENE	9.33E-04		4300.0		5.62.E-01	2.81E-04	EPA webFire database
			TOLUENE	4.09E-04		4300.0		2.46.E-01	1.23E-04	"
			FORMALDEHYDE	1.18E-03		4300.0		7.10.E-01	3.55E-04	"
			ACETALDEHYDE	7.67E-04		4300.0		4.62.E-01	2.31E-04	"
			TOTAL PAH	1.68E-04		4300.0		1.01.E-01	5.06E-05	"
			ACROLEIN	9.25E-05		4300.0		5.57.E-02	2.78E-05	"
			XYLENE	2.85E-04		4300.0		1.72.E-01	8.58E-05	"
			MERCURY	3.01E-07		4300.0		1.81.E-04	9.07E-08	"
			NAPHTHALENE	8.48E-05		4300.0		5.10.E-02	2.55E-05	"
			CO2	1.02E+01	KG/GAL	4300.0			4.83E+01	EPA GHG Emission Factors
			CH4	4.10E-01	G/GAL	4300.0			1.94E-03	"
			N2O	8.00E-02		4300.0			3.78E-04	"
37 (COMB37)	10500206	Bldg. 542	NOx	1.00E+02	LB/10^6 SCF	37.13	10^6 SCF	3.71E+03	1.86E+00	EPA webFire database
		IR Space Heaters	VOC	5.30E+00		37.13		1.97E+02	9.84E-02	"
		Furnances	CO	2.00E+01		37.13		7.43E+02	3.71E-01	"
		Natural gas	SO2	6.00E-01		37.13		2.23E+01	1.11E-02	"
		CU-B118/B119	PM10	8.70E+00		37.13		3.23E+02	1.61E-01	"
			PM2.5	8.70E+00		37.13		3.23E+02	1.61E-01	"
		CU-B118 (4.05 MMBtu/hr)	PM-CON	5.70E+00		37.13		2.12E+02	1.06E-01	"
		54 at 75,000 BTU/hr each	LEAD	5.00E-04		37.13		1.86E-02	9.28E-06	AP-42, Table 1.4-2
		CU-B119 (0.4 MMBtur/hr)	ARSENIC	2.00E-04		37.13		7.43E-03	3.71E-06	AP-42, Table 1.4-4
		4 at 100,000 BTU/hr each	CADMIUM	1.10E-03		37.13		4.08E-02	2.04E-05	"
		4.45/1050*8760	CHROMIUM	1.40E-03		37.13		5.20E-02	2.60E-05	"
		37.12571429	COBALT	8.40E-05		37.13		3.12E-03	1.56E-06	"
		MMCF	MANGANESE	3.80E-04		37.13		1.41E-02	7.05E-06	"
			MERCURY	2.60E-04		37.13		9.65E-03	4.83E-06	"

NSWCPD (FACILITY ID 9724) POTENTIAL TO EMIT

POINT ID (Sub Facility)	SCC #	DESCRIPTION	POLLUTANT	EMISSION FACTOR (1)(2)(3)	UNITS	ANNUAL USAGE	UNITS	ANNUAL EMISSIONS (5) LBS	TONS	COMMENTS
			NICKEL	2.10E-03		37.13		7.80E-02	3.90E-05	"
			2-METHYLNAPHTHALENE	2.40E-05		37.13		8.91E-04	4.46E-07	AP-42, Table 1.4-3
			BENZENE	2.10E-03		37.13		7.80E-02	3.90E-05	"
			DICHLOROBENZENE	1.20E-03		37.13		4.46E-02	2.23E-05	"
			FLUORANTHENE	3.00E-06		37.13		1.11E-04	5.57E-08	"
			FLOURENE	2.80E-06		37.13		1.04E-04	5.20E-08	"
			FORMALDEHYDE	7.50E-02		37.13		2.78E+00	1.39E-03	"
			HEXANE	1.80E+00		37.13		6.68E+01	3.34E-02	"
			NAPHTHALENE	6.10E-04		37.13		2.26E-02	1.13E-05	"
			PHENANTHRENE	1.70E-05		37.13		6.31E-04	3.16E-07	"
			PYRENE	5.00E-06		37.13		1.86E-04	9.28E-08	"
			TOLUENE	3.40E-03		37.13		1.26E-01	6.31E-05	"
			CO2	5.45E-02	KG/SCF	37.13			2.23E+03	EPA GHG Emission Factors
			CH4	1.03E-03	G/SCF	37.13			4.20E-02	"
			N2O	1.03E-04		37.13			4.21E-03	"
38	10300603	Bldg. 4	NOx	1.00E+02	LB/10^6 SCF	34.36	10^6 SCF	3.44E+03	1.72E+00	AP-42, Table 1.4-1
(COMB38)		N.G. Heating Boilers	CO	8.40E+01		34.36		2.89E+03	1.44E+00	"
		CU-B121A/B121B/B121C/B121D	LEAD	5.00E-04		34.36		1.72E-02	8.59E-06	AP-42, Table 1.4-2
			PM10	7.60E+00		34.36		2.61E+02	1.31E-01	"
		Permit limit: 34.36 MMCF	PM2.5	7.60E+00		34.36		2.61E+02	1.31E-01	"
			PM-CON	5.70E+00		34.36		1.96E+02	9.79E-02	"
			SO2	6.00E-01		34.36		2.06E+01	1.03E-02	"
			VOC	5.50E+00		34.36		1.89E+02	9.45E-02	"
			AMMONIA	4.90E-01		34.36		1.68E+01	8.42E-03	EPA webFire Database
			2-METHYLNAPHTHALENE	2.40E-05		34.36		8.25E-04	4.12E-07	AP-42, Table 1.4-3
			BENZENE	2.10E-03		34.36		7.22E-02	3.61E-05	"
			DICHLOROBENZENE	1.20E-03		34.36		4.12E-02	2.06E-05	"
			FLUORANTHENE	3.00E-06		34.36		1.03E-04	5.15E-08	"
			FLOURENE	2.80E-06		34.36		9.62E-05	4.81E-08	"
			FORMALDEHYDE	7.50E-02		34.36		2.58E+00	1.29E-03	"
			HEXANE	1.80E+00		34.36		6.18E+01	3.09E-02	"
			NAPHTHALENE	6.10E-04		34.36		2.10E-02	1.05E-05	"
			PHENANTHRENE	1.70E-05		34.36		5.84E-04	2.92E-07	"
			PYRENE	5.00E-06		34.36		1.72E-04	8.59E-08	"
			TOLUENE	3.40E-03		34.36		1.17E-01	5.84E-05	"
			ARSENIC	2.00E-04		34.36		6.87E-03	3.44E-06	AP-42, Table 1.4-4
			CADMIUM	1.10E-03		34.36		3.78E-02	1.89E-05	"
			CHROMIUM	1.40E-03		34.36		4.81E-02	2.41E-05	"
			COBALT	8.40E-05		34.36		2.89E-03	1.44E-06	"
			MANGANESE	3.80E-04		34.36		1.31E-02	6.53E-06	"
			MERCURY	2.60E-04		34.36		8.93E-03	4.47E-06	"
			NICKEL	2.10E-03		34.36		7.22E-02	3.61E-05	"
			CO2	5.45E-02	KG/SCF	34.36			2.06E+03	EPA GHG Emission Factors
			CH4	1.03E-03	G/SCF	34.36			3.89E-02	"
			N2O	1.03E-04		34.36			3.89E-03	"
39	10300603	Bldg. 29	NOx	1.00E+02	LB/10^6 SCF	17.18	10^6 SCF	1.72E+03	8.59E-01	AP-42, Table 1.4-1
(COMB39)		N.G. Heating Boilers	CO	8.40E+01		17.18		1.44E+03	7.22E-01	"
		CU-B122A/B122B	LEAD	5.00E-04		17.18		8.59E-03	4.30E-06	AP-42, Table 1.4-2
			PM10	7.60E+00		17.18		1.31E+02	6.53E-02	"
		Permit limit: 17.18 MMCF	PM2.5	7.60E+00		17.18		1.31E+02	6.53E-02	"
			PM-CON	5.70E+00		17.18		9.79E+01	4.90E-02	"
			SO2	6.00E-01		17.18		1.03E+01	5.15E-03	"
			VOC	5.50E+00		17.18		9.45E+01	4.72E-02	"
			AMMONIA	4.90E-01		17.18		8.42E+00	4.21E-03	EPA webFire Database
			2-METHYLNAPHTHALENE	2.40E-05		17.18		4.12E-04	2.06E-07	AP-42, Table 1.4-3
			BENZENE	2.10E-03		17.18		3.61E-02	1.80E-05	"
			DICHLOROBENZENE	1.20E-03		17.18		2.06E-02	1.03E-05	"
			FLUORANTHENE	3.00E-06		17.18		5.15E-05	2.58E-08	"
			FLOURENE	2.80E-06		17.18		4.81E-05	2.41E-08	"

NSWCPD (FACILITY ID 9724) POTENTIAL TO EMIT

POINT ID				EMISSION		ANNUAL		ANNUAL EMISSIONS (5)		
(Sub Facility)	SCC #	DESCRIPTION	POLLUTANT	FACTOR (1)(2)(3)	UNITS	USAGE	UNITS	LBS	TONS	COMMENTS
			FORMALDEHYDE	7.50E-02		17.18		1.29E+00	6.44E-04	"
			HEXANE	1.80E+00		17.18		3.09E+01	1.55E-02	"
			NAPHTHALENE	6.10E-04		17.18		1.05E-02	5.24E-06	"
			PHENANTHRENE	1.70E-05		17.18		2.92E-04	1.46E-07	"
			PYRENE	5.00E-06		17.18		8.59E-05	4.30E-08	"
			TOLUENE	3.40E-03		17.18		5.84E-02	2.92E-05	"
			ARSENIC	2.00E-04		17.18		3.44E-03	1.72E-06	AP-42, Table 1.4-4
			CADMIUM	1.10E-03		17.18		1.89E-02	9.45E-06	"
			CHROMIUM	1.40E-03		17.18		2.41E-02	1.20E-05	"
			COBALT	8.40E-05		17.18		1.44E-03	7.22E-07	"
			MANGANESE	3.80E-04		17.18		6.53E-03	3.26E-06	"
			MERCURY	2.60E-04		17.18		4.47E-03	2.23E-06	"
			NICKEL	2.10E-03		17.18		3.61E-02	1.80E-05	"
			CO2	5.45E-02	KG/SCF	17.18			1.03E+03	EPA GHG Emission Factors
			CH4	1.03E-03	G/SCF	17.18			1.94E-02	"
			N2O	1.03E-04		17.18			1.95E-03	"
40	10300603	Bldg. 1000	NOx	1.00E+02	LB/10^6 SCF	34.36	10^6 SCF	3.44E+03	1.72E+00	AP-42, Table 1.4-1
(COMB40)		N.G. Heating Boilers	CO	8.40E+01		34.36		2.89E+03	1.44E+00	"
		CU-B123A/B123B/B123C/B123D	LEAD	5.00E-04		34.36		1.72E-02	8.59E-06	AP-42, Table 1.4-2
			PM10	7.60E+00		34.36		2.61E+02	1.31E-01	"
		Permit limit: 34.36 MMCF	PM2.5	7.60E+00		34.36		2.61E+02	1.31E-01	"
			PM-CON	5.70E+00		34.36		1.96E+02	9.79E-02	"
			SO2	6.00E-01		34.36		2.06E+01	1.03E-02	"
			VOC	5.50E+00		34.36		1.89E+02	9.45E-02	"
			AMMONIA	4.90E-01		34.36		1.68E+01	8.42E-03	EPA webFire Database
			2-METHYLNAPHTHALENE	2.40E-05		34.36		8.25E-04	4.12E-07	AP-42, Table 1.4-3
			BENZENE	2.10E-03		34.36		7.22E-02	3.61E-05	"
			DICHLOROBENZENE	1.20E-03		34.36		4.12E-02	2.06E-05	"
			FLUORANTHENE	3.00E-06		34.36		1.03E-04	5.15E-08	"
			FLOURENE	2.80E-06		34.36		9.62E-05	4.81E-08	"
			FORMALDEHYDE	7.50E-02		34.36		2.58E+00	1.29E-03	"
			HEXANE	1.80E+00		34.36		6.18E+01	3.09E-02	"
			NAPHTHALENE	6.10E-04		34.36		2.10E-02	1.05E-05	"
			PHENANTHRENE	1.70E-05		34.36		5.84E-04	2.92E-07	"
			PYRENE	5.00E-06		34.36		1.72E-04	8.59E-08	"
			TOLUENE	3.40E-03		34.36		1.17E-01	5.84E-05	"
			ARSENIC	2.00E-04		34.36		6.87E-03	3.44E-06	AP-42, Table 1.4-4
			CADMIUM	1.10E-03		34.36		3.78E-02	1.89E-05	"
			CHROMIUM	1.40E-03		34.36		4.81E-02	2.41E-05	"
			COBALT	8.40E-05		34.36		2.89E-03	1.44E-06	"
			MANGANESE	3.80E-04		34.36		1.31E-02	6.53E-06	"
			MERCURY	2.60E-04		34.36		8.93E-03	4.47E-06	"
			NICKEL	2.10E-03		34.36		7.22E-02	3.61E-05	"
			CO2	5.45E-02	KG/SCF	34.36			2.06E+03	EPA GHG Emission Factors
			CH4	1.03E-03	G/SCF	34.36			3.89E-02	"
			N2O	1.03E-04		34.36			3.89E-03	"
41	10300603	Bldg. 633	NOx	1.00E+02	LB/10^6 SCF	33.79	10^6 SCF	3.38E+03	1.69E+00	AP-42, Table 1.4-1
(COMB41)		CU-B130 N.G. Boiler	CO	8.40E+01		33.79		2.84E+03	1.42E+00	"
		CU-B131 N.G. Air Handler	LEAD	5.00E-04		33.79		1.69E-02	8.45E-06	AP-42, Table 1.4-2
		CU-B132 N.G. HVAC Unit	PM10	7.60E+00		33.79		2.57E+02	1.28E-01	"
		CU-B133 N.G. Air Handler	PM2.5	7.60E+00		33.79		2.57E+02	1.28E-01	"
			PM-CON	5.70E+00		33.79		1.93E+02	9.63E-02	"
			SO2	6.00E-01		33.79		2.03E+01	1.01E-02	"
		CU-B130 (0.4 MMBtu/hr)	VOC	5.50E+00		33.79		1.86E+02	9.29E-02	"
		CU-B131 (2.5 MMBtu/hr)	AMMONIA	4.90E-01		33.79		1.66E+01	8.28E-03	EPA webFire Database
		CU-B132 (0.8 MMBtu/hr)	2-METHYLNAPHTHALENE	2.40E-05		33.79		8.11E-04	4.05E-07	AP-42, Table 1.4-3
		CU-B133 (0.35 MMBtu/hr)	BENZENE	2.10E-03		33.79		7.10E-02	3.55E-05	"
		Total: 4.05 MMBtu/hr/1050*8760	DICHLOROBENZENE	1.20E-03		33.79		4.05E-02	2.03E-05	"
		33.78857143	FLUORANTHENE	3.00E-06		33.79		1.01E-04	5.07E-08	"

NSWCPD (FACILITY ID 9724) POTENTIAL TO EMIT

POINT ID (Sub Facility)	SCC #	DESCRIPTION	POLLUTANT	EMISSION FACTOR (1)(2)(3)	UNITS	ANNUAL USAGE	UNITS	ANNUAL EMISSIONS (5) LBS	TONS	COMMENTS
		MMCF	FLOURENE	2.80E-06		33.79		9.46E-05	4.73E-08	"
			FORMALDEHYDE	7.50E-02		33.79		2.53E+00	1.27E-03	"
			HEXANE	1.80E+00		33.79		6.08E+01	3.04E-02	"
			NAPHTHALENE	6.10E-04		33.79		2.06E-02	1.03E-05	"
			PHENANTHRENE	1.70E-05		33.79		5.74E-04	2.87E-07	"
			PYRENE	5.00E-06		33.79		1.69E-04	8.45E-08	"
			TOLUENE	3.40E-03		33.79		1.15E-01	5.74E-05	"
			ARSENIC	2.00E-04		33.79		6.76E-03	3.38E-06	AP-42, Table 1.4-4
			CADMIUM	1.10E-03		33.79		3.72E-02	1.86E-05	"
			CHROMIUM	1.40E-03		33.79		4.73E-02	2.37E-05	"
			COBALT	8.40E-05		33.79		2.84E-03	1.42E-06	"
			MANGANESE	3.80E-04		33.79		1.28E-02	6.42E-06	"
			MERCURY	2.60E-04		33.79		8.79E-03	4.39E-06	"
			NICKEL	2.10E-03		33.79		7.10E-02	3.55E-05	"
			CO2	5.45E-02	KG/SCF	33.79			2.03E+03	EPA GHG Emission Factors
			CH4	1.03E-03	G/SCF	33.79			3.82E-02	"
			N2O	1.03E-04		33.79			3.83E-03	"
42	10500206	Bldg. 633	NOx	1.00E+02	LB/10^6 SCF	98.71	10^6 SCF	9.87E+03	4.94E+00	AP-42, Table 1.4-1
(COMB42)		CU-B124 (51) N.G. Heaters	CO	2.00E+01		98.71		1.97E+03	9.87E-01	"
		Bldg. 519	LEAD	5.00E-04		98.71		4.94E-02	2.47E-05	AP-42, Table 1.4-2
		CU-B125 (6) N.G. Heaters	PM10	8.70E+00		98.71		8.59E+02	4.29E-01	"
		Bldg. 520	PM2.5	8.70E+00		98.71		8.59E+02	4.29E-01	"
		CU-B126 (14) N.G. Heaters	PM-CON	5.70E+00		98.71		5.63E+02	2.81E-01	"
		Bldg. 666	SO2	6.00E-01		98.71		5.92E+01	2.96E-02	"
		CU-B127 (1) N.G. Heaters	VOC	5.30E+00		98.71		5.23E+02	2.62E-01	"
		Bldg. 745	2-METHYLNAPHTHALENE	2.40E-05		98.71		2.37E-03	1.18E-06	AP-42, Table 1.4-3
		CU-B128 (6) N.G. Heaters	BENZENE	2.10E-03		98.71		2.07E-01	1.04E-04	"
		Bldg. 824	DICHLOROBENZENE	1.20E-03		98.71		1.18E-01	5.92E-05	"
		CU-B129 (2) N.G. Heaters	FLUORANTHENE	3.00E-06		98.71		2.96E-04	1.48E-07	"
		Bldg. 1032	FLOURENE	2.80E-06		98.71		2.76E-04	1.38E-07	"
		CU-B134 (1) N.G. Heater	FORMALDEHYDE	7.50E-02		98.71		7.40E+00	3.70E-03	"
			HEXANE	1.80E+00		98.71		1.78E+02	8.88E-02	"
		CU-B124 (7.692 MMBTU/hr)	NAPHTHALENE	6.10E-04		98.71		6.02E-02	3.01E-05	"
		CU-B125 (0.74 MMBTU/hr)	PHENANTHRENE	1.70E-05		98.71		1.68E-03	8.39E-07	"
		CU-B126 (1.765 MMBtu/hr)	PYRENE	5.00E-06		98.71		4.94E-04	2.47E-07	"
		CU-B127 (0.2 MMBtu/hr)	TOLUENE	3.40E-03		98.71		3.36E-01	1.68E-04	"
		CU-B128 (0.325 MMBtu/hr)	ARSENIC	2.00E-04		98.71		1.97E-02	9.87E-06	AP-42, Table 1.4-4
		CU-B129 (0.90 MMBtu/hr)	CADMIUM	1.10E-03		98.71		1.09E-01	5.43E-05	"
		CU-B134 (0.21 MMBtu/hr)	CHROMIUM	1.40E-03		98.71		1.38E-01	6.91E-05	"
		Total:	COBALT	8.40E-05		98.71		8.29E-03	4.15E-06	"
		11.832	MANGANESE	3.80E-04		98.71		3.75E-02	1.88E-05	"
		MMBtu/hr	MERCURY	2.60E-04		98.71		2.57E-02	1.28E-05	"
		11.832/1050*8760	NICKEL	2.10E-03		98.71		2.07E-01	1.04E-04	"
		98.71268571	CO2	5.45E-02	KG/SCF	98.71			5.92E+03	EPA GHG Emission Factors
		MMCF	CH4	1.03E-03	G/SCF	98.71			1.12E-01	"
			N2O	1.03E-04		98.71			1.12E-02	"
43	20100202	Bldg 29	NOx	2.84E+03	LB/10^6 SCF	0.205	10^6 SCF	5.81E+02	2.90E-01	EPA webFire database
(PROC06)		N.G. Emergency Generator	VOC	1.16E+02		0.205		2.37E+01	1.19E-02	"
		CU-GT113	CO	3.99E+02		0.205		8.16E+01	4.08E-02	"
		409 cuft/hr	SO2	6.00E-01		0.205		1.23E-01	6.14E-05	"
		500 hr	PM10	2.01E+01		0.205		4.11E+00	2.06E-03	"
		total: 409*500 = 204500 cuft (0.2045 mmcf)	PM2.5	2.01E+01		0.205		4.11E+00	2.06E-03	"
			PM-CON	1.01E+01		0.205		2.07E+00	1.03E-03	"
			CO2	5.45E-02	KG/SCF	0.205			1.23E+01	EPA GHG Emission Factors
			CH4	1.03E-03	G/SCF	0.205			2.31E-04	"
			N2O	1.03E-04		0.205			2.32E-05	"
44	30703096	Bldg 745	PM10	5.00E-02	LB/HR	2920	HR	1.46E+02	7.30E-02	1994 Emission Inventory Study. (See Note 4)
(PROC25)		Woodworking								Dust Collector Efficiency 90%

NSWCPD (FACILITY ID 9724) POTENTIAL TO EMIT

POINT ID (Sub Facility)	SCC #	DESCRIPTION	POLLUTANT	EMISSION FACTOR (1)(2)(3)	UNITS	ANNUAL USAGE	UNITS	ANNUAL EMISSIONS (5) LBS	TONS	COMMENTS
		P-P101								Assumed hours of operation = 8 hrs/day
45	20300202	Bldg 77H Temporary GTG	NOx						1.17E+02	GTG Permit Emission Limit
(PROC37)	NG/FO	Natural Gas, Fuel Oil	VOC						1.68E+01	"
		CU-M157	CO						8.99E+01	"
			SO2						1.06E+00	"
		PTE based on permit limits	PM10						7.92E+00	"
		Only incl limits for Criteria Pollutants	PM2.5						7.73E+00	"
			PM-CON							AP-42, Table 3.1-2a
			1,3 BUTADIENE							AP-42, Table 3.1-3
			ACETALDEHYDE							"
			ACROLEIN							"
			BENZENE							"
			FORMALDEHYDE							"
			NAPHTHALENE							"
			TOTAL PAH							"
			PROPYLENE							"
			TOLUENE							"
			XYLENE							"
			CO2		KG/SCF					EPA GHG Emission Factors
			CH4		G/SCF					"
			N2O							"
46	10300603	Bldg 77H Anti-Icing Boiler	NOx	5.00E+01	LB/10^6 SCF	35.75	10^6 SCF	1.79E+03	8.94E-01	AP-42, Table 1.4-1
(COMB43)		N.G. Heating Boiler for Temp GTG	CO	8.40E+01		35.75		3.00E+03	1.50E+00	"
		CU-B135	LEAD	5.00E-04		35.75		1.79E-02	8.94E-06	AP-42, Table 1.4-2
		**assumed 4380 (common sense limit I think is	PM10	7.60E+00		35.75		2.72E+02	1.36E-01	"
		8.57 MMBtu/hr	PM2.5	7.60E+00		35.75		2.72E+02	1.36E-01	"
		8.57/1050*4380	PM-CON	5.70E+00		35.75		2.04E+02	1.02E-01	"
		35.74914286	SO2	6.00E-01		35.75		2.15E+01	1.07E-02	"
			VOC	5.50E+00		35.75		1.97E+02	9.83E-02	"
			AMMONIA	4.90E-01		35.75		1.75E+01	8.76E-03	EPA webFire Database
			2-METHYLNAPHTHALENE	2.40E-05		35.75		8.58E-04	4.29E-07	AP-42, Table 1.4-3
			BENZENE	2.10E-03		35.75		7.51E-02	3.75E-05	"
			DICHLOROBENZENE	1.20E-03		35.75		4.29E-02	2.15E-05	"
			FLUORANTHENE	3.00E-06		35.75		1.07E-04	5.36E-08	"
			FLOURENE	2.80E-06		35.75		1.00E-04	5.01E-08	"
			FORMALDEHYDE	7.50E-02		35.75		2.68E+00	1.34E-03	"
			HEXANE	1.80E+00		35.75		6.44E+01	3.22E-02	"
			NAPHTHALENE	6.10E-04		35.75		2.18E-02	1.09E-05	"
			PHENANTHRENE	1.70E-05		35.75		6.08E-04	3.04E-07	"
			PYRENE	5.00E-06		35.75		1.79E-04	8.94E-08	"
			TOLUENE	3.40E-03		35.75		1.22E-01	6.08E-05	"
			ARSENIC	2.00E-04		35.75		7.15E-03	3.58E-06	AP-42, Table 1.4-4
			CADMIUM	1.10E-03		35.75		3.93E-02	1.97E-05	"
			CHROMIUM	1.40E-03		35.75		5.01E-02	2.50E-05	"
			COBALT	8.40E-05		35.75		3.00E-03	1.50E-06	"
			MANGANESE	3.80E-04		35.75		1.36E-02	6.79E-06	"
			MERCURY	2.60E-04		35.75		9.30E-03	4.65E-06	"
			NICKEL	2.10E-03		35.75		7.51E-02	3.75E-05	"
			SELENIUM	2.40E-05		35.75		8.58E-04	4.29E-07	
			CO2	5.45E-02	KG/SCF	35.75			2.14E+03	EPA GHG Emission Factors
			CH4	1.03E-03	G/SCF	35.75			4.04E-02	"
			N2O	1.03E-04		35.75			4.05E-03	"
47	20100102	Bldg 77L PEDAL CAT Diesel Gen (6)	NOx	1.07E+02	LB/10^3 GAL	11631.6	GAL		1.06E+00	Permit Emission Limit
(PROC39)		Diesel Generator	CO	4.50E+00		11631.6		5.23E+01	2.62E-02	Manufacturer Data Sheet, EPA Tier 4
		CU-M158	SOx	3.97E+01		11631.6		4.62E+02	2.31E-01	EPA webFire database
		Permit limits:	PM10	3.10E+00		11631.6		3.61E+01	1.80E-02	Manufacturer Data Sheet, EPA Tier 4
		1.06 tpy NOx	PM2.5	3.10E+00		11631.6		3.61E+01	1.80E-02	"

NSWCPD (FACILITY ID 9724) POTENTIAL TO EMIT

POINT ID (Sub Facility)	SCC #	DESCRIPTION	POLLUTANT	EMISSION FACTOR [1][2][3]	UNITS	ANNUAL USAGE	UNITS	ANNUAL EMISSIONS [5] LBS	ANNUAL EMISSIONS [5] TONS	COMMENTS
		Hours: 300 hr + 24 hr maintenance	VOC	1.20E+00		11631.6	GAL	1.40E+01	6.98E-03	"
		Fuel flow rate: 35.9 gal/hr	BENZENE	1.29E-01	$LB/10^3$ GAL	11631.6		1.50.E+00	7.50E-04	EPA webFire database
			TOLUENE	3.86E-02		11631.6		4.49.E-01	2.24E-04	"
			XYLENE	6.84E-03		11631.6		7.96.E-02	3.98E-05	"
			FORMALDEHYDE	6.63E-02		11631.6		7.71.E-01	3.86E-04	"
			ETHYLBENZENE	3.07E-03		11631.6		3.57.E-02	1.79E-05	"
			NAPHTHALENE	1.29E-02		11631.6		1.50.E-01	7.50E-05	"
			CO2	1.02E+01	KG/GAL	11631.6			1.31E+02	EPA GHG Emission Factors
			CH4	4.10E-01	G/GAL	11631.6			5.25E-03	"
			N2O	8.00E-02		11631.6			1.02E-03	"
48	20100102	Bldg 77L PEDAL HiPower Diesel Gen [6]	NOx	1.77E+02	$LB/10^3$ GAL	16663.2	GAL		1.76E+00	Permit Emission Limit
(PROC40)		Diesel Generator	CO	1.21E+02		16663.2		2.02E+03	1.01E+00	EPA Tier 2 for Nonroad Diesel Engines
		CU-M159	SOx	3.97E+01		16663.2		6.62E+02	3.31E-01	EPA webFire database
		Permit limits:	PM10	9.30E+00		16663.2		1.55E+02	7.75E-02	EPA Tier 2 for Nonroad Diesel Engines
		1.76 tpy NOx	PM2.5	9.30E+00		16663.2		1.55E+02	7.75E-02	"
		Hours: 250 hrs + 12 hr maintenace	VOC	4.60E+01	$LB/10^3$ GAL	16663.2		7.67E+02	3.83E-01	"
		Fuel flow rate: 63.6 gal/hr	BENZENE	1.29E-01		16663.2		2.15.E+00	1.07E-03	EPA webFire database
			TOLUENE	3.86E-02		16663.2		6.43.E-01	3.22E-04	"
			XYLENE	6.84E-03		16663.2		1.14.E-01	5.70E-05	"
			FORMALDEHYDE	6.63E-02		16663.2		1.10.E+00	5.52E-04	"
			ETHYLBENZENE	3.07E-03		16663.2		5.12.E-02	2.56E-05	"
			NAPHTHALENE	1.29E-02		16663.2		2.15.E-01	1.07E-04	"
			CO2	1.02E+01	KG/GAL	16663.2			1.87E+02	EPA GHG Emission Factors
			CH4	4.10E-01	G/GAL	16663.2			7.52E-03	"
			N2O	8.00E-02		16663.2			1.47E-03	"
49	40100336	Bldg. 77H	VOC	6.80E+00	LB/GAL	40.00	GAL	2.72E+02	1.36E-01	Manufacturer Emissions Data and Material Balance
(PROC38)		Parts Washer								
		Permit limit: 40 gal solvent								

*PMtotal = PMcon + PMfilterable

TOTAL CRITERIA POLLUTANTS [6]	
NOx	950.7967
VOC	22.7048
CO	119.6025
SO2	39.8791
PM10	20.9805
PM2.5	20.9390
PM-CON	8.0590
LEAD	0.0118

TOTAL HAP POLLUTANTS	
AMMONIA	7.55E-02
2-METHYLNAPHTHALENE	8.63E-06
BENZENE	4.88E-02
DICHLOROBENZENE	4.31E-04
FLUORANTHENE	1.08E-06
FLOURENE	1.01E-06
FORMALDEHYDE	2.62E-01
HEXANE	6.47E-01
NAPHTHALENE	2.96E-02
PHENANTHRENE	6.11E-06
PYRENE	1.80E-06
TOLUENE	1.95E-03
ARSENIC	7.19E-05
CADMIUM	4.40E-03
CHROMIUM	9.67E-03
COBALT	3.02E-05
MANGANESE	6.59E-01
MERCURY	1.09E-03
NICKEL	7.55E-04
BERYLLIUM	0.00E+00
SELENIUM	4.29E-07
ACETALDEHYDE	3.43E-04

TOTAL GREENHOUSE GAS EMISSIONS	
CO2	177313.89
CH4	6.200
N2O	1.1324
TOTAL COMBINED GHG (TPY)	**177,321.22**

NSWCPD (FACILITY ID 9724) POTENTIAL TO EMIT

POINT ID (Sub Facility)	SCC #	DESCRIPTION	POLLUTANT	EMISSION FACTOR (1) (2) (3)	UNITS	ANNUAL USAGE	UNITS	ANNUAL EMISSIONS (5) LBS	ANNUAL EMISSIONS (5) TONS	COMMENTS
			ACROLEIN		4.13E-05					
			XYLENE		2.24E-04					
			PROPYLENE		0.00E+00					
			ETHYLBENZENE		4.34E-05					
			TOTAL PAH		3.34E-02					
			TOTAL COMBINED HAPS (TPY)		**1.70E+00**					

(1) Emission factors from most recently drafted AP-42 factors unless otherwise noted. Pollutants with "less than" emission factors were not included.

(2) Sulfur emisssions calculations use 0.0015% by weight (S).

(3) PM2.5 and PM10 values estimated using PM Total emission factor from Table 3.1-2a

(4) Emissions based on hours of operation and not material usage.

(5) Total facility potential emissions based on summation of individual source emissions. Basis of calculations or permit limits specified for each source.

(6) Sources that started operation after August 3, 2018 are included in the total PTE for completeness purposes, but are **NOT** included in the RACT III submittal. The NOx PTE without CU-M161, CU-M162, CU-M163, CU-M164, CU-M158, CU-M159 are is 744.58 TPY.

Attachment B – RACT II Plan Approval No. IP16-000235

CITY OF PHILADELPHIA
DEPARTMENT OF PUBLIC HEALTH
AIR MANAGEMENT SERVICES

RACT II PLAN APPROVAL

RACT Plan Approval No. IP16-000235

Effective Date: 3/20/2020

Expiration Date: None

In accordance with provisions of the Air Pollution Control Act, the Act of January 8, 1960, P.L. 2119, as amended, and after due consideration of a Reasonably Available Control Technology (RACT) proposal received under the Pennsylvania Code, Title 25, Chapter 129.96 through 129.100, of the rules and regulations of the Pennsylvania Department of Environmental Protection (PADEP), Air Management Services (AMS) approved the RACT proposal of the facility below for the source(s) listed in section 1.A. Emission Sources of the attached RACT Plan Approval.

*This RACT Plan Approval has been revised to remove sources (CU-B108, CU-M115, CU-M116, CU-M155, and CU-G101) that have shut down since the latest RACT determination from the RACT permit issued March 22, 2016 (PA Permit No. 51-0924 dated 2/9/2016).

Facility:	Naval Surface Warfare Center - Philadelphia Division (NSWCPD)
Permittee:	NSWCPD
Location:	5001 South Broad Street, Code 1023, Philadelphia, PA 19112
Mailing Address:	5001 South Broad Street, Code 1023, Philadelphia, PA 19112
SIC Code(s):	9722
Plant ID:	9724
Facility Contact:	Mark Donato
Phone:	(215) 897-7607
Permit Contact:	Mark Donato
Phone:	(215) 897-7607
Responsible Official:	Dana F. Simon
Title:	Captain, US Navy Commanding Officer

3/20/20

Edward Wiener, Chief of Source Registration

Date

In accordance with provisions of the Pennsylvania Code, Title 25, Chapters 129.96 through 129.100, Air Management Services (AMS) has approved the RACT proposal plans for Naval Surface Warfare Center – Philadelphia Division (NSWCPD) on the above indicated air contamination source(s).

The RACT plan approval is subject to the following conditions:

1. **Purpose:**

   The purpose of this Plan Approval is to establish Nitrogen Oxides (NO_X) Reasonably Available Control Technology (RACT) for NSWCPD. This includes the following emission sources and control equipment:

   A. Emission Sources

      i. Seven (7) testing engines and turbines:

Unit	Description	Heat Input	Fuel Burned
CU-M111	B77H; Engine Testing Gas Turbine DDG-51	226.9 MMBTU/hr (6,180.7 bhp)	Diesel
CU-M112	B77H; Engine Testing Gas Turbine DDG-51	226.9 MMBTU/hr (6,180.7 bhp)	Diesel
CU-M113	B77H; Engine Testing Gas Turbine CG-47	40.6 MMBTU/hr (1,212.8 bhp)	Diesel
CU-M114	B77H; Engine Testing Gas Turbine GTG #2	37.4 MMBTU/hr (1,117.2 bhp)	Diesel
CU-M119	B824; Engine Testing TF-40 Gas Turbine	≤ 42.1 MMBTU/hr (≤ 1,257.6 bhp)	Diesel
CU-M139	B77H; Engine Testing Gas Turbine GTG#1	37.4 MMBTU/hr (1,117.2 bhp)	Diesel
CU-M151	B77H; DD(X) LM-500	51.4 MMBTU/hr (1,535.5 bhp)	Diesel

2. **Approval and Authorization:**

   A. The testing engines and gas turbines will continue to adhere to the standard Navy Planned Maintenance program as defined for shipboard use.

   B. The following testing engines and gas turbines will continue to adhere to the following NO_X emission limits as listed below:

Unit	NO_X Emission Limitation
CU-M111	244 lbs/hr
CU-M112	263 lbs/hr
CU-M113	24.8 lbs/hr
CU-M114	30.3 lbs/hr

Unit	NO_X Emission Limitation
CU-M119	9.14 tons in any rolling 12-month period
CU-M139	29.1 lbs/hr
CU-M151	514.60 lbs/hr (for entire DDX Test Cell*)

* The short term emission limit given for CU-M151 is the emission limit for the entire DDX Test Cell, which can contain up to three turbines whose combined emission rate cannot exceed 514.60 lbs/hr of NO_X.

3. RACT II Implementation Schedule:

A. Upon issuance of this approval, NSWCPD shall begin immediate implementation of the measures necessary to comply with the approved RACT proposal.

4. Monitoring, Recordkeeping, and Reporting Requirements:

A. NSWCPD shall maintain a file containing all the records and other data that are required to be collected to demonstrate compliance with the RACT requirements of 25 Pa Code §§129.96-129.99. These records shall include:

i. Details of the maintenance program for testing engines/turbines at the facility.

ii. Stack test results for each of the seven (7) testing engines and turbines listed above.

B. NSWCPD shall perform an AMS-approved stack test on each of the seven testing engine and gas turbines one time in each 5-year calendar period to demonstrate compliance with 25 Pa Code §129.100(a)(4) and the NO_X emission limits in Condition 2.B.

i. For CU-M111, CU-M112, CU-M113, CU-M114, and CU-M139 each unit shall be tested to demonstrate compliance with its respective NO_X emission limit one time in each 5-year calendar period.

ii. NSWCPD shall conduct a source test on the marine gas turbine ETF-40B (CU-M119) to establish nitrogen oxide (NO_X), carbon monoxide (CO), and particular matter-10 (PM-10) emission factors no later than 90 days after attaining full power of operation. The stack test protocol must be submitted to Air Management Services (AMS) at least 30 days before the test date. The test results must be submitted to AMS within 60 days of testing. If at any time AMS has cause to believe that air contaminant emissions from this source is in excess of the limits specified in this permit, NSWCPD shall be required to conduct whatever tests deemed necessary by AMS to determine the actual emission rates. CU-M119 shall be tested to demonstrate compliance with the NO_X emission limit one time in each 5-year calendar period thereafter.

iii. CU-M151 shall be tested to demonstrate compliance with the NO_X emission limit within 60 days of achieving full capacity—but not later than 180 days after initial start-up—and one time in each 5-year calendar period thereafter.

C. Records shall be retained for at least five years and shall be made available to AMS on request.

5. Revisions:

A. Revisions to any emission limitations incorporated in this RACT Approval will require resubmission as revision to the PA State Implementation Plan. The applicant shall bear the cost of public hearing and notification required for EPA approval as stipulated in 25 Pa Code §129.99(h).

Plan Approval Application

Table of Contents

List of Attachments

Attachment A – GTG Draft Plan Approval No. IP21-000322

Attachment B – GE Water Injection Letter

Attachment C – Control Technology Review

CITY OF PHILADELPHIA

DEPARTMENT OF PUBLIC HEALTH
PUBLIC HEALTH SERVICES
AIR MANAGEMENT SERVICES

Air Management Services
321 University Avenue
Philadelphia PA 19104-4543
Phone: (215) 685-7572
FAX: (215) 685-7593

APPLICATION FOR PLAN APPROVAL TO CONSTRUCT, MODIFY OR REACTIVATE AN AIR CONTAMINATION SOURCE AND/OR AIR CLEANING DEVICE

(Prepare all information completely in print or type in triplicate)

SECTION A - APPLICATION INFORMATION

Location of source (Street Address): 5001 S. Broad Street, Code 1023, Philadelphia, PA 19112	Facility Name: Naval Surface Warfare Center, Philadelphia Division

Owner: U.S Navy	Tax ID No: N/A

Mailing Address: 5001 S. Broad Street, Code 1023, Philadelphia, PA 19112	Telephone No.: (215) 897-7005	Fax No.: ( )

Contact Person: Jennifer Stager	Title: Environmental Program Manager

Mailing Address: 5001 S. Broad Street, Code 1023, Philadelphia, PA 19112	Telephone No.: (215) 897-2241	Fax No: (215) 897-8444

E-mail Address: jennifer.l.stager.civ@us.navy.mil

SECTION B - DESCRIPTION OF ACTIVITY

Application type: ☐ New source ☐ Modification ☐ Replacement ☐ Reactivation ☐ Air cleaning device ☑ Other RACT III	SIC Code: 9711	Completion Date: 01/01/2023

Applicable requirement: ☐ NSPS ☐ NESHAP ☐ Case by Case MACT ☐ NSR ☐ PSD	Does Facility submit Compliance Review Form biannually? ☐ Yes ☑ No If No attach Air Pollution Control Act Compliance Review Form with this application.

Source Description: The purpose of this plan approval application is to submit an alternative, case-by-case Reasonably Available Control Technology (RACT) proposal as required by 25 PA Code §129.114.

SECTION C - PERMIT COORDINATION (ONLY REQUIRED FOR LAND DEVELOPMENT)

Question	YES	NO
1. Will the project involve construction activity that disturbs five or more acres of land?	☐	☑
2. Will the project involve discharge of industrial wastewater or stormwater to a dry swale, surface water, ground water or an existing sanitary sewer system?	☐	☑
3. Will the project involve the construction and operation of industrial waste treatment facility?	☐	☑
4. Is onsite sewage disposal proposed for your project?	☐	☑
5. Will the project involve construction of sewage treatment facilities, sanitary sewer, or sewage pumping station?	☐	☑
6. Is a stormwater collection and discharge system proposed for this project?	☐	☑
7. Will any work associated with this project take place in or near a stream, waterway, or wetland?	☐	☑
8. Does the project involve dredging or construction of any dam, pier, bridge or outfall pipe?	☐	☑
9. Will any solid waste or liquid wastes be generated as a result of the project?	☐	☑
10. Is a State Park located within two miles from your project?	☐	☑

SECTION D - CERTIFICATION

I certify that I have the authority to submit this Permit Application on behalf of the applicant named herein and that the information provided in this application is true and correct to the best of my knowledge and information.

Signature: SIMON.DANA.FRANCIS.1179629174 Digitally signed by SIMON.DANA.FRANCIS.1179629174 Date: 2022.12.16 13:38:03 -05'00' Date ______ Address: 5001 S. Broad Street, Philadelphia, PA 19112

Name & Title: Dana F. Simon, Captain, U.S. Navy Phone: dana.f.simon1.mil@us.navy.mil Fax: 215-897-8481

SECTION E - OFFICIAL USE ONLY

Application No.	Plant ID	Health District	Census Tract	Fee	Date Received

Approved by	Date	Conformance by	Date

SECTION F 1 - GENERAL SOURCE INFORMATION

1. SOURCE						2. NORMAL PROCESS OPERATING SCHEDULE						
	A. Type Source (Describe)	B. Manufacturer of Source	C. Model No.	D. Rated Capacity (Specify units)	E. Type of Materials Processed	A. Amount Processed/yr. (Specify units)	B. Average hr/day	C. Total hr/yr	D. % Throughput/Quarter			
									1st	2nd	3rd	4th
1	Combustion Gas Turbine	General Electric	LM-2500	20 MW	N/A	N/A	24	8760	25	25	25	25
2												
3												
4												
5												

3. ESTIMATED FUEL USAGE (Specify Units)							4. ANNUAL FUEL USAGE						
A. Used in Unit	B. Type Fuel	C. Average Hourly Rate	D. Maximum Hourly Rate	E. Percent Sulfur	F. Percent Ash	G. Heating Value	A. Annual Amounts	B. Average hr/day	C. Total hr/yr	D. % Throughput/Quarter			
										1st	2nd	3rd	4th
1	Natural Gas (Primary)	0.22 MMCF	0.22 MMCF	<0.0015	<0.001	1050 BTU/CF	1395 MMCF	24	8760	25	25	25	25
1	No. 2 Fuel Oil (Backup)	1260 gal	1260 gal	<0.0015	<0.001	140000 BTU/gal	9980088 gal	Backup	-	-	-	-	-

5. IMPORTANT: Attach on a separate sheet a flow diagram of process giving all (gaseous, liquid, and solid) flow rates . Also list raw materials charged to process equipment and the amounts charged (tons/hour, etc.) at rated capacity (give maximum, minimum and average charges describing fully expected variations in production rates). Indicate (on diagram) all points where contaminants are controlled (location of water sprays, hoods or other pickup points, etc.).

SECTION F 1 - GENERAL SOURCE INFORMATION, CONTINUED

6. Describe process equipments in detail.

See next page for full narrative on case-by-case RACT III proposal.

7. Describe fully the methods used to monitor and record all operating conditions that may affect the emission of air contaminants. Provide detailed information to show that these methods provided are adequate.

NSWCPD will monitor all records in accordance with IP21-000322 (see Attachment A). Since the permit is still in draft format, the exact permit conditions are subject to change, but NSWCPD has already started and will continue to monitor these parameters as required.

* GTG and water injection system maintenance and calibration records
* Monthly and 12-month rolling emissions
* Daily operating hours, monthly operating hours, and hours per 12-month rolling period
* Date, time, and duration of GTG operation below 5 MW without water injection, above 5 MW with water injection, and above 5 MW without water injection during periods of startup, shutdown, and/or malfunction
* Natural gas and No. 2 fuel oil usage and fuel sulfur content
* Water injection water-to-fuel ratio, calculated per unit operating hour on a 4-hour rolling average
* Stack test results

8. Describe modifications to process equipments in detail.

There will be no modifications to the GTG. The purpose of this plan approval application is to submit an alternative, case-by-case RACT III proposal as required by 25 PA Code §129.114.

9. Attach any and all additional information necessary to adequately describe the process equipment and to perform a thorough evaluation of the extent and nature of its emissions.

Attachment A - Draft Installation Permit IP21-000322
Attachment B - GE Water Injection Letter
Attachment C - Control Technology Review and Supporting Documentation

- Provide equipment information on this page if sources do not belong to special categories in F2 to F8, otherwise remove this page from this application.
- If there are more equipment, copy this page and fill in the information as indicated

SECTION F 1 - GENERAL SOURCE INFORMATION, CONTINUED

6. Describe process equipments in detail.

CU-M157 is a simple cycle gas turbine (GTG) rated at 20 MW (26,840 HP) that operates on natural gas as the primary fuel and No. 2 fuel oil when natural gas is unavailable, including instances of curtailment by the utility and mechanical issues with the electric natural gas booster pump or other system components. The GTG supplies power to the Compatibility Test Facility (CTF) which is used to support research and development testing for shipboard propulsion and ship service electrical system components. The GTG serves as the primary source of electrical power for the shipboard component testing only. This contingency is necessary to maintain testing during critical periods with minimal interruptions. The GTG is equipped with a water injection system to control NOx emissions.

Table 1 – CU-M157 Emission Limits with Water Injection (>75% Load)

Fuel	Emission Limits (ppm @ 15% O2)		Stack Test Results from January 2022 (ppm @ 15% O2)
	§129.112(g)(2)(v)	IP18-000235 and 40 CFR §60.4330(a)(1)	15 MW w/ Water Injection
Natural Gas	42	25	24.5
Fuel Oil	96	74	38.3

The presumptive RACT III emission limitations under §129.112(g)(2)(v) apply to the GTG, listed in Table 1. When operating the GTG above 5 MW using water injection, stack test results demonstrate compliance with the aforementioned emission limits (see Table 1 above). NSWCPD will continue to conduct performance tests in accordance with IP18-000235, which will in turn demonstrate compliance with the less stringent presumptive RACT NOx emission limits.

Table 2 – CU-M157 Emission Limits without Water Injection (<75% Load)

Fuel	Emission Limits (ppm @ 15% O2)		Stack Test Results from January 2022 (ppm @ 15% O2)
	§129.112(g)(2)(v)	IP18-000235 and 40 CFR §60.4330(a)(1)	5 MW w/o Water Injection
Natural Gas	42	150	74.7
Fuel Oil	96	150	120.9

The GTG does not run continuously, and operations are typically intermittent and at varying loads, which are categorized as low load (<5 MW) and high load (>5 MW). Operations are dependent upon testing schedules and will vary in peak load and duration. Per condition 11(b) of IP18-000235 and draft permit IP21-000322, the GTG can operate without water injection at low load. When operating the GTG at low load without water injection, stack test results demonstrate compliance with permitted emission limits of 40 CFR 60 Subpart KKKK Table 1, but the GTG at low load will not meet the more stringent RACT NOx emission limits (see Table 2 above).

NSWCPD has analyzed the option of operating water injection at low loads, and determined that it would be technically infeasible for the GTG. The manufacturer's recommended operating procedure (see Attachment B) states that the water injection system cannot be used below 5 MW due to the high risk of engine blow out and lowered airflow resulting in poor atomization of the water, inefficient NOx control, and accelerated distress of the combustion system due to water erosion. This is also captured in 40 CFR 60 Subpart KKKK Table 1 for turbines operating at less than 75% of peak load, which requires compliance with the less stringent NOx emission limit of 150 ppm.

NSWCPD has also analyzed the option of including additional controls during operation without water injection, all of which were determined to be technically and economically infeasible. In the original plan approval application for the GTG (dated January 2015), NSWCPD reviewed the technical and economic feasibility for other emission controls before deciding on water injection. See Attachment C for the full control technology review narrative included with the application.

- Selective Catalytic Reduction (SCR) – Due to rapid and frequent changes in engine output, the variations in exhaust temperature, flow rate, and NOx emissions from the CTF would place demands on the SCR controller not found in commercial SCR systems. The addition of an SCR would not allow testing to completely simulate shipboard operations or meet testing objectives. The economic cost is approximately $22,700 to $27,500 per ton of NOx which is not economically viable for NWSCPD.
- Selective Non-Catalytic Reduction (SNCR) – Similar to SCR, due to rapid and frequent changes in adding SNCR would invalidate test results and disrupt operating conditions of the test cell.
- Dry Low Emissions (DLE) Combustion – With frequent and rapid changes to engine output, the risk of engine blowout increases, further reducing NOx control efficiency. Adding DLE would also require a redesign of the gas turbine module and combustor, which would impact NSWCPD’s ability to test propulsion and ship service systems at CTF (increasing risk and cost).

CITY OF PHILADELPHIA
DEPARTMENT OF PUBLIC HEALTH
PUBLIC HEALTH SERVICES
AIR MANAGEMENT SERVICES

Air Management Services
321 University Avenue
Philadelphia PA 19104-4543
Phone: (215) 685-7572
FAX: (215) 685-7593

AIR POLLUTION CONTROL ACT COMPLIANCE REVIEW FORM

Filing Date: December 2022	☑ New Filing	☐ Amended Filing of __/__/__	☐ New Operating Permit ☐ Periodic
Application No:	☑ New Plan Approval	☐ Renew Plan Approval	☐ Operating Permit ☐ Change Owner

Applicant: (non-corporations attach documentation of legal name) Naval Surface Warfare Center, Philadelphia Division (NSWCPD)	Address: 5001 S Broad Street Philadelphia, PA 19112	Tax ID No.: N/A Telephone No.: (215) 897-7005

Form of Management:
☐ Individual ☐ Fictitious name ☐ Partnership ☐ Corporation ☑ Government ☐ Other: _________

If applicant is a corporation attach list of names, business addresses, states of incorporation, taxpayer IDs , and relationships to applicant.

Describe Business Activities:

Naval Surface Warfare Center, Philadelphia Division (NSWCPD) provides machinery engineering support for the current and future Navy. A major part of that mission is construction and operation of numerous full scale testing sites which house a variety of ship components used for the research, development, testing and evaluation of ship propulsion and power generation systems. These test facilities are used to evaluate equipment of various kinds under shipboard conditions in an at-sea environment.

Does the applicant have any other related parties operating in the Commonwealth of Pennsylvania? ☐ Yes ☑ No

If Yes attach a list of :

- Name, Mailing Address, Telephone, and Relationship to the applicant of all related parties, and
- Name and Business Address of the plant manager and general partners of the applicant.

List all plan approvals or operating permits issued by the Department or an approved local air pollution control agency under the APCA to the applicant or related parties that are currently in effect or have been in effect at any time 5 years prior to the date on which this form is notarized. Attach additional sheets as necessary.

Air Contamination Source	Plan Approval/ Operating Permit Number	Location	Issuance Date	Expiration Date
Various	V13-009	N/A	6/13/14	6/13/19
GE LM 2500	IP18-000235	B77H	9/25/2019	3/25/2021

List all incidents of deviations of the APCA, regulations, terms and conditions of an operating permit or plan approval or order by applicant or any related party, using the following format grouped by source and location in reverse chronological order. This list must include items both currently known and unknown to the Department. Attach additional sheets as necessary. See the definition of "deviations" for further clarification.

Date	Location	Plan Approval/ Operating Permit #	Nature of Deviation	Incident Status: Litigation Existing/Continuing; or Corrected/Date
1/10/2020	N/A	IP18-000235	GTG water injection system malfunction resulted in GTG operations above 5MW without water injection	Corrected 1/10/2020. NOV received 8/4/2020. Permit modification in process

CONTINUING OBLIGATION: Applicant is under a continuing obligation to update this form if any additional documented conduct occurs between the date of submission and Department action on the application

I, ________________________________ , being duly sworn according to law, depose and state under penalty of law as provided in 18 Pa. C.S. §4944 and Section 9(b)(2) of the Air Pollution Control Act, 35 P.S. §4009(b)(2), that I am the representative of the Applicant/Permittee, identified above, authorized to make this affidavit. I further state that the information provided with this form, after reasonable inquiry, is true and complete to the best of my belief and that there are reasonable procedures in place to insure that documented conduct and deviations are identified and made part of the compliance review information contained in the Compliance Review Form.

SIMON.DANA.FRANCIS.1179629174 Digitally signed by SIMON.DANA.FRANCIS.1179629174 Date: 2022.12.16 13:44:27 -05'00'

(Signature)

Dana F. Simon

(Print or Type Name)

Captain, U.S. Navy

(Print or Type Title)

Sworn to and subscribed before me this ___day of ____________________, 19

____

Notary Public

Affix Corporate Seal and attach copy of Articles of Incorporation

(Regarding corporate seal and signatures, please refer to Item 4 in instructions.)

Attachment A – GTG Draft Plan Approval No. IP21-000322

City of Philadelphia
Department of Public Health
Air Management Services

DRAFT PLAN APPROVAL

Plan Approval No: **IP21-000322** Date: **XXXXX**

Plant ID: 09724

Owner: United States (US) Navy
Address: 5001 South Broad Street
Philadelphia, PA 19112-1403

Source: Naval Surface Warfare Center, Philadelphia Division (NSWCPD)
Location: 901 Admiral Peary Way,
Philadelphia, PA 19112-1403
Permit Contact: Jennifer Stager, Environmental Engineer
Email: jennifer.stager@navy.mil
Phone: (215) 897-2241

Pursuant to the provisions of Title 3 of the Philadelphia Code, the Air Management Code of February 17, 1995, as amended, and after due consideration of a plan approval application received under the rules and regulations of the Philadelphia Air Pollution Control Board, the City of Philadelphia, Department of Public Health, Air Management Services (AMS) on **XXXXX** approved plans for the installation and temporary operation of the air contamination device(s) described below:

This Plan Approval modifies IP18-000235 dated September 25, 2019. The following are modifications to IP18-000235.

- **Modify the short-term limit for CO and NOx in Condition 4.**
- **Modify Condition 11 to allow operation of the GTG without water injection up to one (1) hour to bring the test site to an emergency stop in the event of a malfunction. The total occurrence shall not exceed 12 hours per calendar year.**
- **Modify fuel throughput limits of Condition 17 based on the emission factors obtained from the January 2022 stack test.**

Source location	Source Description	Manufacturer	Model	Rated Capacity	Type of fuel
Building 77H (Outside)	Gas Turbine Generator (GTG) with water injection system	General Electric	LM-2500	20 MW <u>230.8 MMBtu/hr (Gas)</u> <u>186.4 MMBTU/hr (Oil)</u>	Natural Gas (primary) No. 2 Oil/ JP-5 Oil (back-up)

MMBtu/hr - Million British Thermal Unit per Hour

MW – Megawatt

This Plan Approval expires **XXXXXX**. If the installation has not been completed by this date, an application for either an extension or new plan approval must be made. The conditions of this plan approval will remain in effect until they are incorporated in an operating license. This Plan Approval is subject to conditions prescribed in the attachment.

Edward Wiener
Chief of Source Registration
(215) 685-9426

PLAN APPROVAL CONDITIONS
PLAN APPROVAL NO: IP21-000322
COMPANY: NSWCPD

Emission Limits

1. The gas turbine generator (GTG) and associated air pollution control equipment shall be installed, operated, and maintained in accordance with both the manufacturer's specifications, the specifications in the application (as approved herein) and with good operating practices.

2. The Permittee shall comply with the requirements of its PAL Permit No. 14347 dated July 10, 2019. The Permittee shall comply with the following Plantwide Applicability Limits (PAL) for the following pollutants: [AMS Plan Approval 14347 dated 7/20/2019]

Table 1: PAL Emission Limits

Nonattainment New Source Review (NNSR) PAL for:	
Nitrogen Oxides (NOx)	240.4 tons per rolling 12-month period.
Attainment New Source Review / Pollution of Significant Deterioration (PSD) PAL for:	
Sulfur Oxides (SOx)	54.3 tons per rolling 12-month period
Nitrogen Oxides (NOx)	240.4 tons per rolling 12-month period

(a) In accordance with 25 Pa Code §127.218, the total actual emissions from all sources at the facility shall not exceed the NNSR PAL of 240.4 tons of NOx on a 12-month rolling period. Any change that would result in an increase over the PAL would subject the facility to the NSR requirements specified in 25 Pa Code 127, Subchapter E.

(b) In accordance with 40 CFR §52.21(aa), the total actual emissions from all sources at the facility shall not exceed the PSD PAL of 240.4 tons of NOx and 54.3 tons of SOx per rolling 12-month period for all sources at NSWCPD. Any increase in emissions above these limits will subject the facility to PSD requirements specified in 25 Pa Code §127, Subchapter D.

3. Emissions from the GTG shall not exceed any of the following limits: [Application]

Table 2: Long Term Emission Limits

Pollutant	Emission Limit	
NOx	117	tons per 12-month rolling period.
CO	89.9	tons per 12-month rolling period.
PM_{10}	7.92	tons per 12-month rolling period.
$PM_{2.5}$	7.73	tons per 12-month rolling period.
VOC	1.34	tons per 12-month rolling period.
SO_2	1.06	tons per 12-month rolling period.

4. Short term emissions from the GTG shall not exceed any of the following limits: [Application, Stack Test Results from Jan 2022]

Table 3: GTG Short Term NOx and CO Emission Limits

Pollutant	Operating Scenario	Natural Gas	No.2 Oil /JP-5
NOx	Low (≤ 5 MW) and High Loads (> 5 MW) with Water Injection	21.0 lbs/hr	29.6 lbs/hr
	Low Loads (< 5 MW) Without Water Injection	26.8 lbs/hr	46.86 lbs/hr
CO	Maximum Operating Scenarios	77.1 lbs/hr	36.4 lbs/hr

5. CO emission from the GTG shall not exceed 1% by volume of exhaust gases. [AMR VIII Sec. II.6]

6. Particulate matter (PM) emissions from the GTG shall not exceed 0.04 grain per dry standard cubic foot. [25 PA Code §123.13(c)(i)]

7. In addition to the emission limits of Conditions 2-6, emissions from the GTG shall meet the following [40 CFR 60 Subpart KKKK Table 1 and 40 CFR §60.4330(a)(1)]:

Table 4: 40 CFR 60 Subpart KKKK Emission Limits

Pollutant	Output	Natural Gas	No.2 Oil /JP-5
NOx	During periods of operating at 75% or higher load	25 ppm @ 15% O_2 or 150 ng/J of useful output (1.2 lb/MWh)	74 ppm @ 15% O2 or 460 ng/J of useful output (3.6 lb/MWh)
	During periods of operating at less than 75% of peak load with less than or equal to 30 MW output	150 ppm @ 15% O_2 or 1,100 ng/J of useful output (8.7 lb/MWh)	150 ppm @ 15% O2 or 1,100 ng/J of useful output (8.7 lb/MWh)
PM		0.03 lbs/MMBTU	0.03 lbs/MMBTU
SO_2		110 ng/J (0.90 lb/MWh) gross output	110 ng/J (0.90 lb/MWh) gross output

8. *Visible emissions into the outdoor atmosphere of visible air contaminants in such a manner that the opacity of the emission is either of the following: [25 PA Code §123.41]
   (a) Equal to or greater than 20% for a period or periods aggregating more than three (3) minutes in any one hour.
   (b) Equal to or greater than 60% at any time.

Work Practice Standards

9. NSWCPD shall remodel to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS) when AMS has cause to believe that the attainment or

maintenance of the standards is in jeopardy.

10. The Permittee shall operate and maintain the GTG, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction. [40 CFR §60.4333(a)]

11. The Permittee shall comply with the following:
    (a) The Permittee shall operate the GTG with a water injection system at all times during periods of power output greater than or equal to 5 MW. Emissions from the GTG shall be accounted for using the most recent approved stack test results.
    (b) The Permittee may operate the GTG without water injection up to one (1) hour for each occurrence to bring the test site to an emergency stop in the event of a malfunction, up to thirty (30) minutes to start-up the water injection system, and up to fifteen (15) minutes during intermittent periods of high load (>5 MW).
    (1) Startup is a high load period without water injection that transitions into a high load period with water injection that is sustained for at least ten (10) minutes or at least 50% high load in the following hour. Both periods of high load without water injection (startup) and high load with water injection are preceded and followed by period(s) of low load (<5 MW) for at least ten (10 minutes).
    (2) Intermittent periods are periods of high load without water injection, preceded and followed by low loads for at least (5) minutes.
    (c) These operating scenarios are referred to as high load (> 5 MW) without water injection. The total occurrence of uncontrolled emissions shall not exceed 12 hours per calendar year. The following methodology shall be used to demonstrate that no violation of an emission standard of Condition 7 has occurred during an uncontrolled occurrence. [Application]
        (i) During an uncontrolled occurrence, calculation shall be based on a 4-hour rolling average using uncontrolled and controlled emissions
        (ii) During an uncontrolled occurrence (no water injection), a NOx concentration of 165 ppm shall be used for natural gas.
        (iii) During an uncontrolled occurrence (no water injection), a NOx concentration of 285 ppm shall be used when the GTG is firing fuel oil.
        (iv) If water injection is operating, a concentration of 25 ppm shall be used for natural gas.
        (v) If water injection is operating, a concentration of 42 ppm shall be used for oil.
    (d) When the GTG is operating at less than 5 MW and without water injection, the Permittee shall monitor and record operating hours. Emissions from the GTG without the use of water injection (start-up/shutdown/intermittent) shall be accounted for and reported in the facility's annual emission report using the most recent AMS approved stack test results.

12. The Permittee shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning fuel that requires water or steam injection for compliance. [40 CFR §60.4335(a)]

13. The GTG shall install a non-resettable hour meter, fuel flow meter, and a watt meter. [Application]

14. The GTG's stack height shall be a minimum of 90 feet with the temporary stack conversion to the permanent structure to be complete **by September 25, 2023**. [Application]

15. CU-M149 (P-104 test cell) shall be permanently removed from service upon issuance of this plan approval.

16. CU-M150, CU-M152, and CU-M155 shall no longer operate.

17. The GTG shall only burn natural gas, No. 2 oil, or JP-5 oil. Natural gas shall be the primary fuel for the GTG. The GTG may burn No. 2 fuel oil or JP-5 oil during times of mandatory natural gas curtailment, or any other time natural gas is unavailable. The Permittee shall comply with one of the following operating scenarios per rolling 12-month period. [Application]
    (a) Natural gas usage shall not exceed 603,000,000 cubic feet per rolling 12-month period and the combined fuel usage for No.2 oil and JP-5 shall not exceed 0 gallons per 12-month rolling period, calculated monthly;
    (b) No. 2 oil and JP-5 oil combined usage shall not exceed 9,439,500 gallons of per rolling 12-month period and natural gas usage shall not exceed 0 cubic feet per 12-month rolling period, calculated monthly.
    (c) When burning a combination of natural gas and oil, the Permittee shall meet one of the following limits in the table below, calculated monthly:

    Table 5 below represent the maximum incremental use of each fuel. Emissions from any combination of natural gas and No. 2/ JP-5 fuel between listed operating scenarios shall not exceed the limits in Condition 3 using the latest emission factors from the most recent AMS approved stack test.

Table 5: Maximum Incremental Use of Each Fuel

Percentage of Natural Gas	Natural Gas (MMCF)	Fuel Oil (Gallons)	Percentage of Fuel Oil
0%	0	~~9,439,500~~ 6,223,846	100%
10%	~~60~~ 51	~~8,495,550~~ 5,601,462	90%
20%	~~121~~ 103	~~7,551,600~~ 4,979,077	80%
25%	~~151~~ 128	~~7,079,625~~ 4,667,885	75%

30%	~~181~~ 154	~~6,607,650~~ 4,356,692	70%
40%	~~241~~ 205	~~5,663,700~~ 3,734,308	60%
50%	~~302~~ 257	~~4,719,750~~ 3,111,923	50%
60%	~~362~~ 308	~~3,775,800~~ 2,489,538	40%
70%	~~422~~ 359	~~2,831,850~~ 1,867,154	30%
75%	~~452~~ 385	~~2,359,875~~ 1,555,962	25%
80%	~~482~~ 410	~~1,887,900~~ 1,244,769	20%
90%	~~543~~ 462	~~943,950~~ 622,385	10%
100%	~~603~~ 513	0	0%

In the event of extended use of fuel oil at other than full load scenarios, the NOx emissions will be monitored using the appropriate emission factor established during the most recent stack test to ensure compliance with Condition 3.

(d) The Permittee shall comply with the minimum water to fuel ratio established in the most recent AMS-approved stack test to demonstrate compliance with Condition 7 and 12. Permittee shall ensure the 4-hour rolling average water to fuel injection ratio, calculated per unit operating hour, is above the minimum ratio listed in the table below, as established during the most recent emissions test. Averages will exclude periods without water injection during low load (<5MW) and as specified in Condition 11(b).

(i) Unit operating hour means a clock hour during which any fuel is combusted in the affected unit [40 CFR §60.4420].

Table 6 lists the water to fuel ratios from the most recent stack test January 5-7, 2021. The ratios below will be replaced by future approved emission factors.

Table 6: Average Minimum Water to Fuel Ratios

Test Date	Operating Scenario	Fuel	**Average Minimum Water to Fuel Ratio
1/5/2021	>5 MW with Water Injection	Natural Gas	0.33
		No.2 or JP-5 Oil	0.15
1/5/2021	>15 MW with Water Injection	Natural Gas	0.91
		No.2 or JP-5 Oil	0.89

** Ratio = PPH of water injection / PPH of fuel flow
PPH = pound per hour

18. Fuel burned (natural gas or fuel oil) in the GTG shall not contain total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. For natural gas, the fuel monitoring requirements of 40 CFR §60.4370 is exempt if the facility can demonstrate that the sulfur content of natural gas to be less than 20 grains per 100 standard cubic feet [40 CFR §60.4330a(2), 40 CFR §60.4365]

19. No person shall use commercial fuel oils which contain sulfur in excess of the percentages by weight set forth below: [Air Management Code §3-207 – assures compliance with 25 Pa Code §123.22(e)(2) and 40 CFR §60.4330(a)(2) per exemption under 40 CFR §60.4365(a)]

Grades Commercial Fuel Oil
No. 2 and lighter oil 0.0015% (15 ppm)

20. The GTG shall only be operated for the purposes of testing and operation training. [Exemption from PA Code 129.202]

21. If the GTG is operated other than the purposes of testing and operation training, then the Permittee shall comply with the requirements of PA Code §129.202 (Additional NOx Requirements) and 129.204 (Emissions Accountability).

Testing Requirements

22. Within 60 days after achieving the maximum production rate the GTG will operate, but no later than 180 days of initial start-up, the Permittee shall conduct a NOx, CO, SO_2, and VOC performance test on the GTG to demonstrate compliance with the emission limits of Conditions 3, 4, and 7. The performance test for the GTG shall be conducted at each of the following operating/testing condition below **while burning natural gas**. The water to fuel ratio shall be monitored during testing to establish acceptable operating values and ranges. [40 CFR §60.4400(a), 40 CFR §60.4360, 40 CFR §60.4415(a), and 40 CFR §60.8]
(a) Normal maximum emission scenario with the water injection system.
(b) At a minimal load (5MW) with and without water injection. Emissions from start-up and shutdowns when the GTG is not using water injection shall be accounted for in the facility's annual emission report using the most recent approved stack test

results.

23. Within 60 days of first firing No. 2 Oil or JP-5, the Permittee shall conduct a NOx, CO, SO_2, PM, PM_{10}, $PM_{2.5}$, and VOC performance test on the GTG to demonstrate compliance with the emission limits of Conditions 3, 4, and 7. The performance test for the GTG shall be conducted at each of the following operating/testing condition below **while burning No. 2 Oil or JP-5**. The water to fuel ratio shall be monitored during testing to establish acceptable operating values and ranges. Instead of testing for PM10 and PM2.5, the facility may test for PM and consider all PM emissions to be PM10 and PM2.5. [40 CFR §60.4400(a), 40 CFR §60.4360, 40 CFR §60.4415(a), and 40 CFR §60.8]
    (a) Normal maximum emission scenario with water injection system.
    (b) At a minimal load (5MW) with and without water injection. Emissions from start-up and shutdowns when the GTG is not using water injection shall be accounted for in the facility's annual emission report using the most recent approved stack test results.

24. The Permittee shall conduct subsequent tests for NOx and SO_2 on an annual basis (not more than 14 calendar months from the previous test) to demonstrate compliance with Condition 7. [40 CFR §60.4400 and 40 CFR §60.4415]

25. The Permittee shall conduct subsequent performance test on the GTG for CO and VOC every five (5) years. Subsequent PM tests shall be conducted when requested by AMS.

26. Each test required under Conditions 22 through 25, shall be conducted in accordance with EPA Reference Methods, 40 CFR 60 Subpart KKKK (if applicable), 25 Pa Code Chapter 139, and the most current PADEP Source Testing Manual. The owner or operator of the facility shall use the following reference methods to demonstrate compliance:
    (a) 40 CFR Part 60 Appendix A, Method 5 and EPA Reference Method 202 shall be used to determine Particulate Matter.
        (i) Instead of testing for PM10 and PM2.5, the facility may test for PM and consider all PM emissions to be PM10 and PM2.5.
    (b) U.S.E.P.A. Reference Methods 201/201A and 202 shall be used to determine PM10.
    (c) U.S.E.P.A. Reference Methods 201A and 202 shall be used to determine PM2.5.
    (d) 40 CFR Part 60 Appendix A, Method 7E or 20 shall be used to determine NOx [40 CFR §60.4400(a)(1)(i)].
    (e) 40 CFR §60 Method Appendix A Methods 25A and 18 or 40 CFR 60 Method 25A and 40 CFR Part 63 shall be used to determine VOC.
    (f) SO_2 shall be determined using one of the following methodologies:
        (i) The sulfur content of the natural gas must be collected using total sulfur Method ASTM D5287 and analyzed using ASTM D1072, D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377. The sulfur content of the No. 2 oil must be collected using total sulfur Methods ASTM D4177 or Section 14 of ASTM D4057; and analyzed using ASTM D129, D1266, D1552, D2622, D4294, or D5453. Alternatively, if the total sulfur content of the gaseous

fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377, which measure the major sulfur compounds, may be used. [40 CFR §60.4415(a)(1)(i)-(ii)]

(ii) Measure the SO_2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19-10-1981-Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in Appendix A, and measure and record the electrical and thermal output from the unit. Then use equation 6 of 40 CFR §60.4415 to calculate the SO_2 emission rate. [40 CFR §60.4415(a)(2)]

(iii) Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in Appendix A of this part. In addition, the Permittee may use the manual methods for sulfur dioxide ASME PTC 19-10-1981-Part 10. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in Appendix A to calculate the SO_2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in 40 CFR §60.4350(f) to calculate the SO_2 emission rate in lb/MWh. [40 CFR §60.4415(a)(3)]

(iv) The Permittee may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas. The Permittee must use one of the following sources of information to make the required demonstration [40 CFR §60.4360 and 40 CFR §60.4365]:

(A) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas; or

(B) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of 40 CFR 75 appendix D is required.

27. For testing required under Conditions 22, 23, 24, and 25, the Permittee shall submit a test protocol to AMS for approval at least 30 days prior to the test date. All test results shall be submitted within 60 days after completion of the test.

Monitoring and Recordkeeping Requirements

28. The Permittee shall monitor and keep comprehensive and accurate records of the following for at least five (5) years:

(a) Maintenance and calibrations conducted on the GTG and water injection system to assure compliance with Conditions 1 and 12.

(b) Monthly combined NOx and SOx emissions to verify that the PAL limits specified in Condition 2 have not been exceeded, on a rolling 12-month basis. The facility wide emissions shall be calculated based on fuel usage, operating hours, AMS approved stack tests, manufacturer's specifications, or AP-42 emission factor per the facility's PAL permit 14347 dated 7/10/2019. Emission calculation and records shall include emissions from start-ups, shutdowns, and malfunctions. [40 CFR § 52.21(aa)(12), AMS Plan Approval 14347 dated 7/10/2019]

(c) Records required by the PAL 14347 dated 7/10/2019. Records required by the PAL permit shall be kept for at least 10 years.

(d) For the GTG, monthly emissions from the GTG to demonstrate compliance with the emission limits in the table in Condition 3. Emissions shall be calculated based on fuel usage and the most recent AMS approved stack test.

Tables 7 and 8 lists the emission factors from the most recent stack test January 5-7, 2021. The emission factors below will be replaced by future approved emission factors. The Permittee shall use most conservative emission factor for each pollutant when operating at low or high loads with water injection. Permittee shall use the low load without water injection emission factor when operating at less than or equal to 5MW without water injection.

Table 7: Natural Gas Emission Factors

Test Date	Operating Scenario	Fuel	Pollutant	Emission Factor
1/5/2021	≤ 5MW without Water Injection	Natural Gas	NOx	26.8 lb/hr
			CO	34 lb/hr
			VOC	0.44 lb/hr
			SO_2	0.017 lb/MMBTU or 0.003 lb/MWh
1/5/2021	15 MW with Water Injection	Natural Gas	NOx	16.9 lb/hr
			CO	77.1 lb/hr
			VOC	1.15 lb/hr
			SO_2	0.018 lb/MMBTU or 0.001 lb/MWh

Table 8: No. 2 Fuel Oil or JP-5 Oil Emission Factors

Test Date	Operating Scenario	Fuel	Pollutant	Emission Factor
1/6/2021	≤5 MW without		NOx	46.86 lb/hr

	Water Injection	No.2 or JP-5 Oil	CO	40.25 lb/hr
			VOC	0.48 lb/hr
			SO_2	0.08 lb/MMBTU or 0.016 lb/MWh
1/6/2021	15 MW With Water Injection	No.2 or JP-5 Oil	NOx	28.6 lb/hr
			CO	36.4 lb/hr
			VOC	0.51 lb/hr
			SO_2	0.08 lb/MMBTU or 0.005 lb/MWh

(e) Number of hours per month the GTG operated using a non-resettable hour meter.

(f) The Permittee shall monitor and keep records of the date, time, and duration when the GTG operated above 5 MW without water injection. The Permittee shall calculate the total operating hours per calendar year monthly to demonstrate compliance with Conditions 11(b) and 11(c).

(g) The Permittee shall monitor daily operating hours for each operating scenario below to demonstrate compliance with Conditions 11(a) and 11(d). Verification or calculations shall be kept per Condition 28(d) to demonstrate compliance with Condition 3.

(ii) Date, time, and duration when the GTG operated below 5 MW without water injection.

(ii) Date, time, and duration when the GTG operated above 5 MW with water injection.

(h) Monthly natural gas and No. 2 oil/JP-5 oil usage to demonstrate compliance with Conditions 17(a)-(c).

(i) 4-hour rolling average water to fuel ratio, calculated per unit operating hour, to demonstrate compliance with Condition 17(d).

(j) The sulfur content of natural gas and oil to demonstrate compliance with Conditions 18 and 19. Compliance may be demonstrated by the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.0015 weight percent 15 ppmw), the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat. [Exemption from 40 CFR §60.6370, 40 CFR §60.4365 and assures compliance with Air Management Code §3-207]

(k) Performance test results.

Reporting Requirements:

29. The Permittee shall report excess emissions and monitor downtime in accordance with 40 CFR 60§60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunctions. [40 CFR 60.4375(a)]

30. For the purpose or reports required under 40 CFR §60.7(c) and for the combustion turbine using water to fuel ratio monitoring, periods of excess emission and monitor downtime that must be reported are defined as follows: [40 CFR §60.4380]
    (a) Any excess emission is any unit operating hour in which the 4-hour rolling average water to fuel ratio, as measured by the continuous monitoring system, falls below that acceptable water to fuel ratio as established during the most recent performance test. Any unit operating hour in which no water or steam is injected into the turbine when fuel is being burned that requires water or steam injection for NOx control will also be considered as excess emission except as specified in Condition 11(b) and 11(c).
    (b) A period of monitor downtime is any unit operating hour in which water is injected into the GTG but the essential parametric data needed to determine the water to fuel ratio are unavailable or invalid.
    (c) Each report must include the average water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

* This is a local or/and state requirement only and it is not Federally enforceable.

Attachment B – GE Water Injection Letter

Dave Hartshorne
GE Marine Product Line Manager

One Neumann Way, M/D S156
Cincinnati, OH 45215
USA

T 513 552 2930
F 513 552 5005
C 513 708 9762
dave.hartshorne@ge.com

May 31, 2017

To: Steven Pesarchick
2S Cog/Gas Turbines Life Cycle Support - Code 423
Naval Surface Warfare Center - Philadelphia Division

Subject: TM2500 Water Injection Minimum Operating Power Level

Reference: Your email of May 24th, 2017

Dear Steve,

Further to our discussion earlier this week, the following is GE's recommendation for minimum operating conditions with water injection for NOx control down to 25ppm NOx.

For continuous operation, GT power must be maintained above 5MW when NOx water is on-line. Water injection at power levels down to 3MW are acceptable for transient operation, or during start-up while water flow is brought on line, but continuous operation is not recommended at these power levels.

Operation with water injection to achieve 25ppm NOx below 5MW results in excessively high water to fuel ratio's with a high risk of engine blow-out, and the facility tripping offline.
In addition, the low airflow at power levels below 5MW results in poor atomization of the water, inefficient NOx control, and accelerated distress of the combustion system due to water erosion.
Please advise if you require additional information.

Best regards,

Dave Hartshorne
GE Marine Product Line Manager

cc.

Enclosure (2)

Attachment C – Control Technology Review

4 Control Technology Review

The project consists of a LM-2500 GTG that will primarily combust natural gas with No. 2 fuel oil or JP-5 as a backup fuel to ensure proper shutdown of the GTG and EDTF during an interruption of the natural gas supply. Emissions of criteria pollutants will not be subject to Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER). However, emissions of NO_x will be controlled to meet the requirements of NSPS Subpart KKKK during operations.

Emissions of other pollutants, including HAPs, will be minimized by using clean fuels and annual limited operation. Natural gas will be the primary fuel with limited use of No. 2 fuel oil / JP-5 as a backup fuel. In addition, water injection will minimize NO_x emissions. A discussion of control measures evaluated for criteria pollutant emissions is provided below.

4.1 Best Available Technology (BAT)

BAT is defined in §121.1 as "equipment, devices, methods or techniques as determined by the Department which will prevent, reduce or control emissions of air contaminants to the maximum degree possible and which are available or may be made available." In January 2013, PADEP issued a revised General Permit BAQ-GPA/GP-5, General Plan Approval and/or General Operating Permit, (henceforth, "GP-5"), for natural gas compression and/or processing facilities. It includes BAT limits for emissions from simple-cycle gas turbines. Although GP-5 will not be used to permit the proposed equipment (the turbine will not be used for natural gas compression), GP-5 does specify control levels that are considered BAT for a simple-cycle natural gas-fired combustion turbines greater than or equal to 15,000 bhp.

Due to the nature of the configuration and operation of the proposed GTG, the control levels specified in GP-5 will not be achieved. The following subsections provide a discussion on the combustion turbine BAT options. It is important to note that the proposed operation of this GTG will be significantly different than that of units that are operated for profit (electric generation, production power, etc.). The GTG will use an existing Navy LM-2500 gas turbine. It will be converted to dual fuel and retrofitted with a feasible emission control system. This GTG is proposed to be installed to support testing only and will not be used as a facility asset. The proposed GTG uses are outlined in Section 2.2. Similar to the other turbines that have been installed at NAVSSES, the testing plan has a maximum utilization early on in the program and then significantly drops to a lower level in subsequent years. For example, the DD(X) Marine Gas Turbine Land Based test Facility, PA #05037, was permitted for the fuel use equivalent of 1,000 hours per year. However the most active year operating the gas turbine was 667 hours per year. The average over that time period was 260 hours per year. This GTG has a requested permit limit of 330 million cubic feet per inch per year which is the equivalent of 1,500 hours per year of full-load operation; however, the 10-year projected average operations is approximately 700 hours per year.

4.1.1 NO_x Control

For NO_x, the control technologies evaluated as BAT are selective catalytic reduction (SCR), Selective Non-Catalytic Reduction (SNCR), Dry Low Emissions (DLE) Combustion, and Water Injection. NAVSSES has determined that water injection is the only technically and economically feasible control option for the turbine. As such, it is proposed that water injection is utilized while the turbine is in operation. Other pre- and post-combustion emission control approaches are not viable due to the required frequent changes in speed and power of the GTG to meet the testing objectives of the EDTF. Additionally, because of the low operating hours the NO_x removal beyond the use of water injection during steady state operations proves to be minimal. For this reason it has been concluded the post-combustion control technologies are cost prohibitive.

4.1.1.1 Selective Catalytic Reduction

Several design factors must be considered when implementing SCR controls; operating temperature, sulfur content of the fuel, design of the ammonia injection system and catalyst maintenance. Inlet temperature optimization is critical when using SCR. Temperatures below 500°F inhibit the reaction while temperatures above 850°F promote oxidation of NH_3 to NO_x.

Fuel sulfur content must be considered in a potential SCR system application. The SCR catalyst promotes oxidation of sulfur dioxide (SO_2) to sulfur trioxide (SO_3) which, in the presence of water, forms sulfuric acid (H_2SO_4). The typical conversion rate of SO_2 to SO_3 is approximately 2%.

Enclosure (2)

Ammonia can react with sulfuric acid in the exhaust gas to produce particulate compounds: ammonium bisulfate and ammonium sulfate. Ammonium bisulfate is a corrosive solid and can be produced when the exhaust gas temperature is below 699°F. Ammonium sulfate forms at lower temperatures and poses less material damage problems due to its non-corrosive properties. If formed in significant quantities, these sulfates can cause severe plugging and/or corrosion. Prevention of such build ups is achieved through the use of lower sulfur fuels and/or the control of ammonia slip to levels below 5 ppm. Small deposit rates can be managed through periodic in situ catalyst washing.

A major concern with NO_x reduction using SCR catalyst is "ammonia slip". Strict control of the ammonia injection system must be kept in order to keep the NH_3/NO_x ratio at a level such that all of the ammonia is reacted. Ideal conditions are usually not realistic and thus most SCR catalyst manufacturers estimate approximately 10 ppmv of ammonia slip under normal operating conditions. Obviously, improper system operation would result in either a high NH_3 slip or conversely a lower NO_x removal efficiency.

The major difference which will have a substantial effect on ammonia slip and NO_x reduction is the comparatively very rapid and frequent changes in engine speed and power output at EDTF. The variations in temperature and NO_x emissions will place demands on the SCR controller not found in commercial SCR installations. If the controller is not able to react to the rapid changes, increased ammonia slip and increased NO_x emissions will result.

Another operation factor worth noting is the catalyst preheat time. Typically, the catalyst is preheated for 10 to 15 minutes before ammonia injection is initiated. The preheat source is the engine exhaust. During the preheat period, the SCR is providing little if any NO_x emission control. Some test cycles only have durations of 10 to 15 minutes. Therefore, a test run may be completed before the SCR system would be functional.

Installation of SCR on the GTG will require development of advanced ammonia injection technology. A sophisticated controller will be necessary to regulate the amount of ammonia injected as the NO_x concentration changes in conjunction with engine power levels. If the controller is not able to respond to the rapid power changes, the potential for excessive ammonia slip increases and NO_x emissions will not be effectively controlled. SCR units serving simple and combined cycle (cogeneration) gas turbine installations require ammonia injection controllers which have to respond to small modulations in engine power output. Therefore, controllers which exist for field installations are not adequate to respond to the rapid power changes which typically occur within a minute or less during test cycles.

In addition to the NO_x concentration change, exhaust temperature and flow-rate changes will impact SCR effectiveness. Exhaust temperatures for the installation will, for the most part, fall within the applicable range. However, some test cycles will be shorter than the required preheat time. Further, the long term effect of temperature cycling on the mechanical integrity of the catalyst is unknown. It is reasonable to assume that the catalyst life will be shortened. Exhaust flow rates will vary by a factor of approximately five, i.e., 40 pounds per second to 200 pounds per second. Although of lesser concern than the NO_x concentration and exhaust temperature changes, such flow rate variation is not typical to conventional stationary gas turbine installations.

In summary, when testing at EDTF requires rapid and frequent changes in engine output, thus the variations in temperature, exhaust flow rate, and NO_x emissions from test facilities would place demands on the SCR controller not found in commercial SCR installations. Also, adding SCR onto the GTG will change the operating conditions of the facility. Changing these conditions would not allow testing to completely simulate shipboard operations as required and would therefore invalidate the testing results. Therefore, SCR systems cannot be considered viable for application to the GTG for EDTF.

Furthermore, the cost effectiveness of a SCR system is approximately $25,700 per ton of NO_x removed. This is presented in Appendix F of this document. This is without the use water injection. If pre-controlled with water injection the cost effectiveness becomes even more cost prohibitive and well beyond the threshold under which the Department has ruled as economically viable. It is assumed that the water injection will control NO_x emissions to 25 ppmvd @ 15% O_2. The SCR would further control NO_x to 15 ppmvd @ 15% O_2 or a control efficiency of 87%. The control costs are referenced from GP-5.

4.1.1.2 Selective Non-Catalytic Reduction

Selective non-catalytic reduction ("SNCR") is a post-combustion technology that reduces NO_x using ammonia or urea injection. One of these chemicals is added to the combustion products where they react at elevated temperatures (1,600°F to 2,200°F) with NO_x to form molecular nitrogen. The primary limiting factor restricting SNCR application is that it is only viable over a fairly narrow temperature range and there is potential for the production of by-product emissions. For both ammonia and urea injection, incomplete reactions will result in "ammonia slip". It is also possible to increase NO_x emissions if the upper temperature range is exceeded. Similar to SCR, adding SNCR will disrupt the operating conditions of the test cell and invalidate test results. Accordingly, this alternative is not feasible.

4.1.1.3 Dry Low Emissions (DLE) Combustion

DLE was developed to achieve low emissions without using water or steam as diluents. A DLE combustor utilizes the principle of lean premixed combustion. However, instead of one single concentric ring (standard LM-2500 design) a DLE combustor uses two or three rings with premixers depending on the gas turbine type. This multiple ring configuration is to allow for "staging" during operation. Implementation of a DLE combustor is a pre-combustion emissions control technology with significant NO_x emission potential. However, the following considerations lead to this being a non-viable option:

- This emission control technology is designed around the steady-state operation of the gas turbine and the main feature of DLE technology is to operate with a lean fuel mixture in order to keep the combustion temperature at an acceptable level. For DLE, the LM-2500 has three rings arranged in the combustor dome of the engine. Above 50% power, all three rings are fueled and combustion takes place downstream of the zones. It is important however to note that DLE only guarantees NO_x emission reduction at loads from 75% and above. It is anticipated that testing protocols will require significant periods of operation below this load level. In cases where a load is suddenly changed the fuel to air mixture may become too lean. This increases the risk of a blowout, consequently increasing NO_x emissions, and if fuel is still being supplied, spontaneous combustion might occur. Similar to the post-combustion emission control approaches discussed the constant change in speed and power output of the GTG required to meet testing objectives would make this technology not viable.
- The nature of testing requires the use of both natural gas and liquid fuel types. While the majority is designed to operate utilizing natural gas, bumpless transitions between fuels is a requirement. A DLE turbine operating on both liquid and natural gas has an extremely more complicated configuration than a single fuel turbine. In addition to a gas fuel system, it needs a liquid fuel system with accompanied manifolds and valves. The premixer is modified with a liquid fuel circuit added to the gas premixer, and leads to a more complex control system. The gas generator can be started on either natural gas or on liquid fuel, but no on a combination of the two. When operating on liquid fuel, it is necessary to purge the liquid portion when switching to natural gas. Gas containing any liquid may damage the premixers and the combustor, and polluted gas may give component problems. For this reason, DLE is not a viable option for the test objectives.
- The GTG is utilizing an existing LM-2500 and its associated engine module. This Navy engine module design addressed the thermal management needs of the gas turbine, and has been vigorously tested and has numerous surface fleet installations (LM-2500 is the most widely used gas turbine in surface fleet combatants). The introduction of a DLE combustor will alter the gas turbine footprint and require a redesign of the gas turbine module. A redesign that would introduce unnecessary risk and cost to EDTF and impact the ability of the Navy to test propulsion and ship service systems at EDTF. In addition to redesign, maintenance costs are significantly higher. These higher costs are mainly related to a more expensive combustor.

4.1.1.4 Water Injection

Another approach to reducing NO_x formation is to reduce the flame temperature by introducing a heat sink into the flame zone. Water is a very effective means of achieving this goal. The principle behind this control technology is to reduce the peak combustion temperature and formation of thermal NO_x by injecting De-Ionized (DI) or treated water in to the combustor.

Substantial quantities of purified water are required to suppress NO_x emissions. Equipment manufacturers recommend the maximum level of dissolved impurities for water injection into a gas turbine engine combustor be less than 2 ppm. At the EDTF provisions can be made in order to meet the required demand.

Wet controls affect gas turbine performance in two ways: power output increases and efficiency decreases. A penalty in overall efficiency must be paid for the additional fuel required because the heat of vaporization energy cannot be recovered. However, gas turbine power output is enhanced because of the additional mass flow through the turbine. The energy from the added mass flow and heat capacity of the injected water can be recovered in the turbine, which results in an increase in power output

There are several technical considerations associated with water injection NO_x control. Injecting water into a combustor affects several parameters:

- Combustion Stability/Flameout. A major issue for water injection under transient operation comes from instabilities within the combustor. Flame quenching from excessive heat losses and the blowing downstream of flames from excessive air velocities are some mechanisms of combustor instability. At the idle state, the engine has to meet a balance of conditions in order to operate properly. "Dry" steady-state fuel consumption must provide a minimum margin for flame stability during fluctuations of ambient temperature and humidity. With water injection, upward adjustment of the idle fuel-consumption rate is required to compensate for conditions.
- Carbon Monoxide Emissions. As more and more water is added to the combustor and there is a reduction in flame temperature which decreases NO_x, a point is reached at which a sharp increase in carbon monoxide is observed.
- Erosion and Wear. Water injection increases dynamic pressure oscillation activity in the turbine combustor. This activity can increase erosion and wear in the hot section of the turbine, thereby increasing maintenance requirements. As a result, the turbine must be removed from service more frequently for inspection and repairs to the hot section components. The injection of water into the combustion cover/fuel nozzle area, while effective in controlling NO_x emission, has a tendency to impinge on the nozzle tip swirler and on the liner cap/cowl assembly resulting thermal strain which usually leads to cracks.

With an increase in power output requirements leading to increased water injection, eventually a point will be reached when the flame will blow out. This point is the absolute limit of NO_x control with water injection. Each pound of water injected into a combustor represents a 1000 Btu heat sink. In the idle condition, when the flame stability is the most delicate, water injection represents a massive quenching heat sink that the combustor flames must survive. Fortunately, the idle-condition flame needs little or no water addition to suppress NOx because of the low flame temperature. During rapid transients, the water-fuel ratio falls as the engine power falls. Water flow must decrease fast enough to avoid flame-quenching. Given a fuel flow rate upstream of the fuel manifold, a controller can compute the required water flow given the current state of the engine. However, water mixed with the fuel in the fuel manifold prior to the termination of water flow may quench the flame during a rapid deceleration. Provisions to the fuel flow rate during decelerations may need to be made in order to prevent flameout. During "dry" operation, the steady-state fuel flow rate falls below the baseline requirements for a short period of time. Due to this condition, with water injection, potential flameout is magnified. Close coordination with the GTG vendor will be necessary to ensure the water injection system will support the operational profiles of the test program.

Despite additional maintenance requirements and operational impacts, for temperature ranges and transient operating conditions that will be present, water injection is the only viable option for emissions mitigation.

4.1.1.5 NO_x Control Summary

In conclusion, a review of BAT conclusively demonstrates that, for the following reasons, only water injection is a viable option for the installed GTG at EDTF:

- Post-combustion emission control approaches are not viable due to the required frequent changes in speed and power of the GTG to meet testing objectives.
- DLE combustor is not a viable option due to the required changes in speed and power of the GTG to meet testing objectives and the impact this approach would have on the engine module. Additionally, a new engine module design would be needed, requiring extensive modeling and testing to validate its performance and will introduce unnecessary risk to the test program at EDTF and a significant financial burden.
- Water injection is the only viable option for the GTG.

4.1.2 CO and VOC Control

The use of an oxidation catalyst is the main control technology for both CO and VOC that was evaluated as BAT by the DEP. Appendix H contains the economic analysis for the oxidation catalyst. Based on the planned hours of operation, the cost per ton of CO and hydrocarbons removed is approximately $22,500 and therefore it is considered cost prohibitive. These calculations were derived based on the methodology used in the PADEP "Technical Support Document, General Permit GP-5, January 31, 2013" along with the costing information contained in the USEPA memorandum written by Sims Roy entitled "Oxidation Catalyst Costs for New Stationary Combustion Turbines." This memorandum evaluated the costs for multiple models of combustion turbines from both GE (including the LM-2500) and Solar. The data in this memo was based on 1998 costs; therefore, the capital cost and annual costs were adjusted using the Chemical Engineering Plant Cost Index (CEPCI) value ratio from 1998 to 2014.

Enclosure (2)

Additionally, it has been shown that at lower load levels and turbine exhaust temperatures the effectiveness of the catalyst decreases. Because the typical operating profiles will include extended periods of varying and lower load levels, the catalyst performance can neither be predicted nor guaranteed.

Therefore, the use of good combustion practices in accordance with manufacturer's specifications is proposed as BAT for the GTG. Similar to the other post-combustion control analysis, the pre-controlled CO emission rate is based on the operation of the turbine utilizing water injection.

4.1.3 Particulate Matter

The Pennsylvania DEP has determined that BAT for particulate matter is 0.03 lb/MMBtu. Based on the emissions information provided in Appendix D, the proposed GTG will emit particulate matter at the following rates:

- • 0.0066 lb/MMBtu when firing natural gas, and
- • 0.0120 lb/MMBtu when firing fuel oil.

Therefore, combustion of natural gas and low or ultralow sulfur fuel is proposed as BAT for particulate matter.

4.2 Summary

Based on the information provided above, water injection and compliance with NSPS Subpart KKKK is proposed for the GTG.

- • For NO_x, the natural gas limit is 25 ppmvd at 15% O_2 or approximately 1.2 pounds per megawatt hour (lb/MWh) of useful output. The limit for fuel oil combustion is 74 ppmvd at 15% O_2 or approximately 3.6 lb/MWh of useful output.
- • For SO_2, the emission limit is 110 ng/J (approximately 0.90 lb/MWh) gross output or potential emissions of 26 ng/J (0.060 lb SO_2 per MMBtu) heat input.

To ensure compliance with the NO_x limitation, the Navy will install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption (natural gas or no. 2 fuel oil) and the ratio of water to fuel being fired in the turbine.

Compliance with the SO_2 limit will be demonstrated through the use of pipeline quality natural gas. Compliance will be confirmed through fuel sulfur content records in the form of a valid purchase contract, tariff sheet, or transportation contract for the fuel which specifies the sulfur content to be 500 parts per million by weight (equivalent to 0.05% sulfur) or less for oil and 20 grains per 100 standard cubic feet or less for natural gas.

Appendix F.
BAT Analysis Supporting Documentation

Oxidation Catalyst - BAT Analysis

From pages 39-41 of GP-5 TSD:

Emission limits/control targets for simple cycle turbines equal to or greater than 15000 bhp		
NOx	15 ppm @ 15% O2	
CO	10 ppm @ 15% O2	or 93% reduction
NMNEHC	5 ppm @ 15% O2, as propane	or 50% reduction
PM	0.03 lb/MMBtu	

Assumptions

8,000 btu/hp-hr
20 MW (Rated)
1,341 hp/MW (USEPA AP 42 - App A)
26,820 hp

Emissions		**CO**		**VOC (Total Hydrocarbons)**	
Uncontrolled:	(with water injection for NO_2)	33	lb/hr	5.3	lb/hr
		1.23E-03	lb/hp-hr	1.98E-04	lb/hp-hr
		1.54E-01	lb/MMBtu	2.47E-02	lb/MMBtu
		68.61	ppm @ 15% O2	-	ppm @ 15% O2
Controlled:		**10**	**ppm @ 15% O2**	9	ppm @ 15% O2, as propane
Control Efficiency:		85%		**50%**	**reduction**
Operating Hours (annual average):		1500		1500	
Uncontrolled:		24.75	tpy	3.98	tpy
Controlled:		3.61	tpy	1.99	tpy
Emission Reduction:		21.14	tpy	1.99	tpy
Emission Reduction (CO + VOC):		23.13	tpy		

Based on 1999 USEPA Sims Roy Memo "Oxidation Catalyst Costs for New Stationary Combustion Turbines"
Costs Adjusted Using Chemical Engineering Plant Cost Index (CEPCI) Ratio

Total Capital Cost (1998)	$ 1,103,989.00	
CEPCI Adjustment Factor 1998-2014 (580.2/389.5)	1.49	
Total Capital Cost (2014)	**$ 1,644,504.28**	
Total Annual Cost (1998 - 6-yr annualized costs)	$ 348,060.00	
CEPCI Adjustment Factor 1998-2014 (580.2/389.5)	1.49	
Total Annual Cost (2014)	**$ 518,470.89**	(Total Direct Annual Costs + Total Indirect Annual Costs)
Annual CO + VOC Reduction (tons)	23.13	
Cost Effectiveness ($/ton removed)	**$ 22,415.19**	for CO and VOC combined

SCR - BAT Analysis

From pages 39-41 of GP-5 TSD:

Emission limits/control targets for simple cycle turbines equal to or greater than 15000 bhp			
NOx	15	ppm @ 15% O2	
CO	10	ppm @ 15% O2	or 93% reduction
NMNEHC	5	ppm @ 15% O2, as propane	or 50% reduction
PM	0.03	lb/MMBtu	

Assumptions

8,000	btu/hp-hr
20	MW (Rated)
1,341	hp/MW (USEPA AP 42 - App A)
26,820	hp

Emissions		**NOx**	
Uncontrolled:	(without water injection)	90.2	lb/hr
		6.34E-04	lb/hp-hr
		7.92E-02	lb/MMBtu
		114.19	ppm @ 15% O2
Controlled:		15	ppm @ 15% O2
Control Efficiency:		87%	
Operating Hours (annual average):		1500	
Uncontrolled (assuming no water injection):		67.65	tpy
Controlled:		8.89	tpy
Emission Reduction:		58.76	tpy

Based on Calculations from GP-5 TSD pg. 77

Total Capital Investment	$ 3,517,178.33
Labor and Maintenance Materials	
Operating Labor	$ 42,752.00
Supervisory Labor	$ 6,412.80
Maintenance	$ 169,073.36
Catalyst Replacement	$ 297,433.41
Catalyst Disposal	$ 5,445.41
Reagent	$ 16,850.79
Dilution Stream	$ 10,008.69
Performance Loss	$ 44,388.83
Blower	$ 4,438.88
Overhead	$ 201,304.74
Taxes, Insurance, and Administration	$ 140,800.23
Capital Recovery (10 yrs @ 10%)	$ 572,404.58
Total Annual Costs	**$ 1,511,313.72**
Annual NOx Reduction (tons/yr)	58.76
Cost Effectiveness ($/ton removed)	**$ 25,718.73**

December 30, 1999

MEMORANDUM

FROM: Sims Roy
Emission Standards Division
Combustion Group

TO: Docket A-95-51

SUBJECT: Oxidation Catalyst Costs for New Stationary Combustion Turbines

The purpose of this memorandum is to summarize information on the cost of oxidation catalyst control for new stationary combustion turbines. Catalyst vendors provided information to EPA on the costs of acquiring, installing, and operating oxidation catalysts for HAP reduction for various turbines; these costs were applied to seven model turbines ranging in size from 1.13 megawatts (MW) to 170 MW. The total capital and annual costs were then estimated using methodologies from the OAQPS Control Cost Manual. A detailed description of the cost methodologies is given in Attachment A.

The total capital and annual costs for each model turbine are presented in the table below. The annual costs were estimated for both the guaranteed life of the catalyst (3 years) and the "typical" life of the catalyst (6 years).

Model Turbine	Total Capital Cost ($)[a]	Total Annual Cost ($)	
		3-Year Costs	6-Year Costs
GE PG 7121EA, 85.4 MW	3,272,268	1,157,833	956,998
GE PG 7231FA, 170 MW	4,753,816	1,673,902	1,382,131
GE PG 6561B, 39.6 MW	1,736,369	631,334	524,762
GE LM25000, 27 MW	1,103,989	415,818	348,060
Solar Centaur 40, 3.5 MW	677,525	268,560	226,974
Solar Mars T12000, 9 MW	485,196	202,673	172,898

Enclosure (2)

Model Turbine	Total Capital Cost ($)[a]	Total Annual Cost ($)	
		3-Year Costs	6-Year Costs
Solar Saturn T1500, 1.13 MW	364,154	161,431	139,086

[a]Costs reflect mid-1998 figures.

Attachment A

MEMORANDUM

DATE: May 14, 1999

SUBJECT: Stationary Combustion Turbines Control Options Cost Information Summary

The purpose of this memorandum is to summarize the cost information that has been received for control options to date. This information will be used with model turbines developed for the Stationary Combustion Turbines source category as part of estimating the national impacts of viable regulatory options.

Background

In support of MACT determinations for new and existing combustion turbines, a set of model turbines has been developed that can be used to evaluate the national impact of control options being considered. The following approach will be used to determine national impacts:

1) Develop model turbines
2) Estimate control costs for each control option for each model turbine
3) Estimate emission reduction for each control option for each model turbine
4) Relate model turbines to turbines in the EPA Inventory Database for Stationary Combustion Turbines
5) Extrapolate from the inventory database population to the national population
6) Determine regulatory options
7) Estimate economic impacts for each regulatory option

Cost information has been received that will be used to estimate the control costs for each option being considered on a model turbine basis. This memorandum reflects the cost information that has been received to date. Any additional cost data received from vendors will be incorporated, as necessary, at a later time.

Cost Information

The methodology in the OAQPS Control Cost Manual will be used to determine the annual cost of control technologies. The OAQPS methodology provides generic cost categories and default assumptions to estimate the installed costs of control devices. Direct cost inputs are required for certain key elements, such as the capital costs of the control device. Other costs, such as installation, are then estimated based on percentages of the direct cost inputs.

In the OAQPS methodology, five cost categories are used to describe the annual cost of a control device. These are as follows:

1) Purchased Equipment Costs (PEC), which include the capital cost of the control device and auxiliary equipment, instrumentation, sales tax, and freight;
2) Direct Costs for Installation (DCI), which are the construction-related costs associated with installing the catalyst;
3) Indirect Costs for Installation (ICI), which include expenses related to engineering and start-up;
4) Direct Annual Costs (DAC), which include annual increases in operating and maintenance costs due to the addition of the control device; and
5) Indirect Annual Costs (IAC), which are the annualized cost of the control device system and the costs due to tax, overhead, insurance, and administrative burdens.

The cost that will be used in model turbine analyses is the total annual cost, which is the sum of the Direct Annual Costs (DAC) and the Indirect Annual Costs (IAC). The following information reflects the capital and operating costs that have thus far been obtained from vendors on the control technologies under consideration. Cost estimates are in 1998 dollars unless otherwise indicated.

Catalytic Systems

- **CO Oxidation Catalyst Systems**

Several vendors were contacted for capital and operating-related costs for CO oxidation catalysts. The following general information was requested:

1) What is the cost range of the catalyst material?
2) Would this number change in considering three flow ranges, i.e., small, medium, and large, starting with a minimum flow of 100 Mlbs/hour and ending with ~3000 Mlbs/hour?
3) What operating temperature ranges with respect to high CO removal/oxidation are recommended?
4) What happens during start-up and low load operation? What would be the result of a prolonged operation with gas turbine exhaust temperatures of ~500°F?
5) What are recommended space requirements and would flow straightening equipment be necessary?
6) What is the cost of reactor housing, required steel support, foundation needs and ductwork?

Cost information for CO oxidation catalysts was received from Engelhard, a catalyst vendor, and Nooter/Eriksen, a heat recovery steam generator (HRSG) vendor. Generalized estimates were also received for costs associated with increased pressure drops and retrofit applications. The information received is summarized below.

Engelhard

Engelhard CO catalysts are manufactured with a special stainless steel foil substrate which is corrugated and coated with an alumina washcoat. The washcoat is impregnated with platinum group metals. The catalyzed foil is folded and encased in welded steel frames, approximately 2 ft. square, to form individual modules. The individual modules are installed within the support frame. The modules typically weigh approximately 50 lb. each. The number of modules required increases with gas flow. Substrate depth and corrugation patterns can vary depending on project requirements. Typically, performance is warranted for 2 to 3 years with an expected life of 5 to 7 years. Typical guarantees are based on a ±15% gas velocity profile distribution. The catalyst is not a hazardous material and in most cases can be recycled to reclaim the precious metals. Engelhard can also provide catalysts on a ceramic substrate.

Engelhard provided costs for a simple cycle turbine installation (catalyst at turbine discharge temperature) for six turbine exhaust flows ranging from 28.4 lb/sec to 984.0 lb/sec. These costs were based on an oxidation catalyst that would achieve 90% CO conversion efficiency and 1" pressure drop across the catalyst panels (not total system pressure drop). The costs provided include the cost of an internal support frame and catalyst modules only. These costs are shown in Table 1.

Table 1. CO Oxidation Catalyst Costs Provided by Engelhard

Turbine Exhaust Flow (lb/sec)	Turbine Exhaust Temperature (F)	Required Inside Liner Cross Section (sq. ft.)	Estimated Cost Catalyst + Frame[a]
28.4	1050	67	$140,000
41.0	819	90	$155,000
318.0	990	716	$600,000
658.0	998	1522	$1,100,000
812.0	975	1881	$1,450,000
984.0	1116	2388	$1,550,000

[a]Costs reflect mid-1998 figures.

Regression analysis on the cost data in Table 1 suggest there is a nearly linear relationship between catalyst cost and exhaust flow rate ($r^2 = 0.993$, when Catalyst cost = 1541.8*(lb/sec) +

102370). Therefore, in estimating catalyst costs for the model turbines, the capital cost of a CO catalyst and frame for a given exhaust flow rate can be calculated using this relationship.

Information was also provided by Engelhard in response to the questions posed concerning operating issues associated with operating CO oxidation catalysts. A graph showing that lower performance/conversion accompanies lower temperatures was supplied. Typically, the catalysts Engelhard provides for gas turbine installations are supplied to a Heat Recovery Steam Generator (HRSG) supplier. The CO catalyst is generally installed within a HRSG. Supplemental firing usually is performed to increase steam production and thus gas temperatures at the catalyst and conversion requirements can be impacted by supplemental firing. Engelhard typically meets given HRSG cross section and maximum specified pressure drop allowed.

Engelhard indicated that reasonable retrofit estimates could not be provided due to many site-specific requirements. Their scope includes an internal support frame and catalyst modules which are installed inside the HRSG housing and as such, issues including flow straightening, housing, foundations, etc., are handled by other vendors.

Nooter/Eriksen

Nooter/Eriksen has become virtually sole sourced to Engelhard's Camet catalyst for their oxidation catalysts and provided an estimate of $650,000 for a 60% CO oxidation catalyst (no support frame or casing) in a GE Frame 7F installation (3,500,000 lb/hr with a catalyst temperature of approximately 900°F). They indicated that the price variation is approximately linear with mass flow and would approximately double to achieve 90% conversion. They were unable to comment on HAP destruction. The CO catalyst is occasionally required to also oxidize volatile organic compounds (VOCs), in which cases the catalyst is generally effective with unsaturated VOCs only and the catalyst must be located in a higher temperature window.

For high CO oxidation (90%), a temperature range of approximately 700°F to 760°F is preferred. If VOC oxidation is also required, the temperature window generally increases to 950°F to 1,100°F. It was indicated that prolonged operation at 500°F will not generally harm an oxidation catalyst unless the combustion turbine is operating with a high soot concentration in the exhaust, although there is little oxidation activity at 500°F.

Concerning retrofit issues, it was indicated that new ductwork to redirect flow outside of the original flow path would probably have the effect of obsoleting the greater portion of the HRSG. Most catalyst system guarantees are based on even flow distribution (typically ±15% RMS of the mean) entering the catalyst. If flow distribution devices were not originally included with the HRSG, this could increase the overall HRSG pressure loss by 0.5" to 1.0" W.C.

Generalized Pressure Drop Costs

Installation of a catalyst system will increase the pressure drop experienced by the turbine exhaust flow. The additional pressure drop results in a decrease in turbine power output. If the turbine is not operating at full load, additional fuel can be burned to make up for the lost power (fuel penalty). The fuel penalty is assessed as the cost of increased fuel, which is calculated by assuming a percentage heat rate increase per inch of pressure drop due to the increased exhaust backpressure on the turbine that results from installing an oxidation catalyst. An equation for the fuel penalty was provided by the Gas Research Institute, which is based on an anticipated heat rate increase of 0.105% per inch pressure drop, $2/MMBtu for natural gas, and a 9,000 Btu/hp-hr baseline.

If the unit is operating at full load, the loss in power cannot be regained by burning additional fuel and will result in a loss in electricity sales. The costs associated with the power loss depend on site-specific factors, such as value of lost product or capital and annual costs for equipment required to make up for the power loss. Information on the loss in annual sales at different selling prices for electrical power was provided to EPA by Dow Chemical Company. For a GE Frame 7 turbine, the annual cost (lost sales) per inch of water pressure drop may be estimated using the following relationship: Annual Cost ($/inch) = 1,160*Power Value ($/Mwh) + 100.

Generalized Retrofit Costs

Estimates for retrofit costs were provided to EPA by Dow Chemical Company. Site-specific factors can have a major impact on the cost of retrofitting a catalyst control system to an existing turbine installation. In general, the heat recovery unit (if one exists) must be altered, ductwork and piling supports must be added, and piping, electrical conduits, and wiring must be lengthened. Some turbine installations have enough space between the turbine exhaust and the heat recovery unit to add the catalyst system. In cases where space is very limited, the heat recovery unit might have to be removed and replaced with a new vertical style unit. Estimates were provided for retrofit costs for adding a catalyst system to an ABB Type 11 turbine (gas flow rate = 580 lb/sec). The retrofit costs totaled about $800,000, which included $100,000 for ductwork. The cost of down time must also be estimated. It is difficult to extrapolate from the costs provided for this unit since the complexity and cost associated with retrofit installations varies so much by site.

- **Other Catalytic Systems**

Cost information in the form of comparisons to SCR systems for NOX control were received for SCONOx and XONON. More detailed cost information is needed from each vendor before an accurate assessment can be made concerning the cost of using these systems in conjunction with the model turbines. The information provided on these two systems is summarized below.

SCONOx™

Cost information for SCONOx was submitted by Goal Line Environmental Technologies LLC. The information consisted of a cost comparison model between SCONOx and SCR (selective catalytic reduction). The comparison is difficult to use for HAPs since it was based on NOX control and therefore takes into account cost issues concerning ammonia use in the SCR system. The lifetime cost (10 years) for the reduction of NOX from 20 ppm to 2.5 ppm for a typical 270 MW plant was estimated as $12,970,970 for the SCONOx system and $17,882,560 for an SCR system. This analysis would need to be significantly adapted to be used constructively in model turbine cost analyses.

XONON

A cost comparison of the XONON system was provided by Catalytica Combustion Systems. The comparison consisted of estimates for DLN (dry low NOX), DLN + SCR (selective catalytic reduction), and XONON for controlling NOX from two different turbine models. As with the SCONOx information, the use of ammonia is a cost consideration that needs to be excluded when considering the cost of the XONON system.

Lean pre-mix (LPM) Combustors

Cost information for lean pre-mix combustors was taken from the "Alternative Control Techniques Document -- NOX Emissions from Stationary Gas Turbines" (ACT). The incremental capital costs for LPM units relative to diffusion flame units are provided for eight turbines in the ACT. A regression formula was developed where the incremental capital cost is a function of turbine rating (MW). This relationship is as follows:

$$\text{Incremental capital cost (1990\$)} = 21454.3*\text{MW} + 408431;\ r^2 = 0.981$$

It is not expected that the maintenance requirements for an LPM unit will be different than for a standard design; therefore, the incremental capital cost is the only cost to be considered in calculating annual costs. According to the ACT, retrofit costs are 40 to 60 percent greater than new installation costs.