CITY OF PHILADELPHIA
Department of Public Health
Environmental Protection Division
Air Management Services

InterOffice Memo

To:	File
From:	Daniel Henkin
Date:	April 20th, 2020
Subject:	2008 8-Hour RACT Analysis for Exelon Generating Company - Richmond Station (PLID # 04903)

Introduction:

The Clean Air Act (CAA) requires that moderate (or worse) ozone nonattainment areas implement reasonably available control technology (RACT) controls on all major sources of VOC and NO_X. Philadelphia County is part of the Philadelphia-Wilmington-Atlantic City moderate ozone nonattainment area for the 2008 8-hour ozone NAAQS. This document presents the findings of a RACT evaluation for the 2008 8-hour ozone standard for this facility.

The SIP revision does not adopt any new regulations. It incorporates the provisions and requirements contained in the amended RACT approval for the facility, which are determined to satisfy the requirements for the 2008 National Ambient Air Quality Standards (NAAQS) for ozone.

Company Description:

Exelon Generation Company - Richmond Generating Station owns and operates an electric utility at 3901 North Delaware Avenue, Philadelphia, PA, 19137. Equipment used at the facility includes two (2) simple cycle combustion turbines.

Applicability for NO_X and VOC RACT II:

Exelon - Richmond is a major source of NO_X due to having potential NO_X emissions greater than 100 tons per year, the major source threshold in Philadelphia County that is applicable to NO_X RACT for the 2008 8-hour ozone NAAQS.

Exelon - Richmond is not a major source of VOC, due to having potential VOC emissions not greater than 50 tons per year, the major source threshold in Philadelphia County that is applicable to VOC RACT for the 2008 8-hour ozone.

Process Descriptions:

The facility's air emission sources contributing to NO_X emissions include the following:

- Two (2) simple cycle combustion turbines each rated 66 MW (838 MMBTU/hr) firing No. 2 Oil and Kerosene.

Previous RACT Considerations:

As a result of the 1-hour RACT determination, the facility was re-evaluated for the 1997 8-hour RACT Standard. The resulting case-by-case RACT Plan Approval, dated 2/9/2016, PA Permit Number 51-4903, was approved into the SIP by EPA on 10/07/2016 (81 FR 69691). The applicable units to RACT I are the same as in this RACT II Plan Approval—two simple cycle combustion turbines each rated 66 MW (838 MMBTU/hr) firing No. 2 Oil and Kerosene. These sources are, under the RACT I Plan Approval, subject to the following requirements:

- Replacing the prior NO_X emission limits of each combustion turbine, of 0.7 lbs/MMBtu, with 0.68 lbs/MMBtu and 569.84 lbs/hr.
- A maximum rolling 12-month capacity factor of 15% for each turbine, calculated and recorded on a monthly basis.
- The installation, maintenance and operation of the combustion turbines in accordance with manufacturers' specifications.
- Monitoring and recordkeeping of daily fuel usage, and net generation for each combustion turbine on a monthly basis.
- Performing an AMS-approved stack test on one combustion turbine every 5 years to demonstrate compliance with the NO_X emission. If the test results are above 0.34 lbs/MMBtu or 284.92 lbs/hr (50% of the limits), the other combustion turbine shall also be tested during that 5-year period.
- Maintaining a file containing all the records and other data that are required to be collected to demonstrate compliance with NO_X RACT requirements of 25 Pa Code §§129.91-129.94. These records shall include records of the monitoring requirements of [the 1997 8-hour RACT I] Plan Approval. The records shall provide sufficient data and calculations to clearly demonstrate that the requirements are met.

AMS has determined that the RACT I requirements will be superseded by individual case-by-case RACT II determinations for the two sources at the facility. RACT II requirements are no less stringent than the RACT I requirements.

NO_X RACT Analysis for the 2008 8-hour Ozone Standard:

The following were considered possible NO_X controls for each combustion turbine: Water Injection, Fuel Switch (conversion to natural gas), Selective Catalytic Reduction (SCR), and Dry Low-NO_X combustors.

To switch to natural gas would result in NO_X emissions reductions of around 65%. This option requires the installation of a new gas pipeline and a pressure regulating station. There is no gas service to this building currently. Estimation from PGW have been in the neighborhood of four (4) million dollars to run this line (permits, survey and staking, cleaning & grading, trenching, pipe stringing, lowering in & backfilling, hydrostatic testing, cleanup & restoration, and pipe and accessories cost). This cost does not include the pressure regulating station. Considered alongside with the detailed environmental assessment of the impacts of the pipeline on the surrounding media, industrial, and residential areas surrounding the facility, the technology is considered not technically feasible for the RACT affected units.

Dry Low-NO_X combustors utilize a staged combustion process to minimize residence time in the high temperature portion of the flame such that there is excess oxygen compared to fuel resulting in a lower flame temperature. The use of a Dry Low-NO_X burner firing No. 2 oil requires the concurrent use of water injection. General Electric has not yet developed a Dry Low-NO_X burner retrofit for firing No. 2 oil for this model combustion turbine firing No. 2 oil. This control technology is therefore not technically feasible for these turbines.

SCR injects ammonia upstream of a catalyst. NO_X, ammonia (NH_3), and oxygen (O_2) react on the surface of the catalyst to form nitrogen (N_2) and water (H_2O). NO_X emissions would be reduced by around 90%.

Water Injection increases thermal mass by dilution which reduces peak temperatures in the flame zone. From a GE website giving an overview of technical solutions: "for non-Dry Low Emissions (DLE) turbines without a NO_X abatement system, a water injection system can be added that lowers NO_X emissions to 25 ppm (gas fuel) or 42 ppm (liquid fuel)." Based on conversations between the facility and a GE representative, 42 ppm has not been demonstrated on this vintage combustion turbine firing oil. The units in question were installed in 1972. Per vendor data included with submitted RACT analysis, this control technology can achieve a rate of 90 ppmv at 15% O_2. When compared with the presumed inlet 176 ppmv @ 15% O_2, this control technology would reduce NO_X emissions by around 49%.

Baseline NO_X emissions for each unit was determined based on the existing 0.68 lbs/MMBTU NO_X emission limit, equivalent to 176 ppmv @ 15% O_2. Based on an 838 MMBTU/hr capacity, 8,760 hours per year, the NO_X emission limit, and 15% capacity factor limit, baseline emissions are 374.38 tons per year for each unit. Exelon Richmond did not consider emissions averaging, as both units are identical with identical existing limits.

Table 1: Cost Analysis Summary for Exelon Richmond CT 91 and CT 92

Source	Control Technology	Baseline NO_X Emissions (TPY)	NO_X Reduction (%)	NO_X Reduction (TPY)	Total Annualized Cost	Cost Effectiveness ($/Ton)
Exelon Richmond	Water/Steam Injection	374.38	49	182.79	$1,938,025	$5,301
	SCR	374.38	90	336.95	$1,899,993	$5,639

All of these control options have been determined economically unreasonable. Additionally, these units typically operate no more than 10 hours in a month or 20 hours annually, with actual emissions a fraction of their potential to emit.

Each of the two turbines has a NO_X emission limit of 0.68 lbs/MMBtu. AMS has determined the lbs/MMBtu limits to be RACT because stack test data has shown the turbines can comply with these limits under existing technology. The most recent NO_X testing conducted on 12/12/2018 provided results of 0.55 lbs/MMBtu and 417.1 lbs/hr for CT 91, and 0.61 lbs/MMBtu and 477.2 lbs/hr for CT 92, which indicate the current limits are appropriate for RACT. The previous testing in 2013 also demonstrated compliance with these limits.

The previous calculation method for the rolling 12-month capacity factor has been replaced with language from the RACT II regulations found under 25 Pa Code §129.97(c)(7)(ii). The previous calculation method was:

$$\frac{Last\ 12\ months\ net\ generation\ (MWH)}{Maximum\ capcaity\ of\ unit\ (MW) \times 24\ hrs/day \times No.of\ dats\ in\ last\ 12\ months}$$

The new language from 25 Pa Code §129.97(c)(7)(ii) states:

> *For an electric generating unit, the annual capacity factor is the ratio of the unit's actual electric output (expressed in MWe/hr) to the unit's nameplate capacity (or maximum observed hourly gross load (in MWe/hr) if greater than the nameplate capacity) multiplied by 8,760 hours during a period of 12 consecutive calendar months.*

While this language is placed within the Presumptive RACT section, the citation is a broad definition for electric generating units, so using this calculation method in a case-by-case determination is appropriate.

Thus, AMS proposes as RACT for each combustion turbine a rolling 12-month capacity factor limit of less than 15% (based on net generation), a NO_X emission limit of 0.68 pounds per MMBtu, and a requirement to install, maintain, and operate the unit in accordance with manufacturer's specifications.

Conclusions and Recommendations:

AMS proposes as RACT for the 8-hour ozone standard the following revisions to the SIP-approved RACT Plan Approval (PA Permit Number 51-4903) for the Exelon - Richmond Station:

- NO_X emission limits of each combustion turbine of 0.68 lbs/MMBTU and 569.84 lbs/hr.
- For each combustion turbine a rolling 12-month capacity factor limit of less than 15% (based on net generation), citing 25 Pa Code §129.97(c)(7)(ii):
  - "For an electric generating unit, the annual capacity factor is the ratio of the unit's actual electric output (expressed in MWe/hr) to the unit's nameplate capacity (or maximum observed hourly gross load (in MWe/hr) if greater than the nameplate capacity) multiplied by 8,760 hours during a period of 12 consecutive calendar months."
- Removal of the following condition, which references requirements that are not related to NO_X or VOC and are not applicable to RACT:
  - "The operation of the aforementioned combustion turbines shall not at any time result in the emission of visible air contaminants in excess of the limitations specified in Section 123.41, particulate matter in excess of the limitations specified in Section 123.11 or sulfur oxides in excess of the limitations specified in Section 123.22, all Sections of Chapter 123 of Article III of the Rules and Regulations of the Department of Environmental Resources, or in the emission of any of these or any other type of air contaminant in excess of the limitations

specified in, or established pursuant to, any other applicable rule or regulation contained in Article III."

4/20/20

Edward Wiener, Chief of Source Registration **Date**

Detailed Calculations Summary

The below table specifies the system parameters for each of the two combustion turbines.

Table 2: System Parameters for Cost Analysis

System Parameter	Value	Units / Description
Input Rating (Q_b)	838	MMBtu/hr
MW Full Capacity	66	MW
Capacity Factor (CF)	15%	TVOP
Assumed NOx Inlet	0.68	lbs/MMBtu - RACT I Limit
NO_X	569.84	lbs/hr - RACT I Limit * Input Rating
Net Plant Heat Input Rate	12.697	MMBtu/MW
HHV of Fuel	137560	Btu/gal, Value from TVOP
MWhs/yr Output	86724	MWhs per year with Capacity Factor

The below cost analysis examines the application of Selective Catalytic Reduction (SCR) on one of the two GE Frame 7B Simple Cycle Combustion Turbine engines located at the Exelon Generation Company – Richmond Generating Station's facility located at 3901 North Delaware Avenue, Philadelphia PA 19137. Primary Source: EPA Air Pollution Cost Control Manual, Section 4 - NOx Controls, Chapter 2 - Selective Catalytic Reduction. All cited "Equations" are drawn from this primary source, last updated June 12, 2019.

Table 3: Cost Analysis for SCR

System Parameter	Value	Units / Description
Heat Rate Factor (HRF)	1.270	Dimensionless - Equation 2.6
ηNO_X	90%	90% Removal Rate of NO_X for a utility CT
NO_X Removal Rate	336.946	ton/yr - Equation 2.11
Stoichiometric Ratio Factor (SRF)	1.05	Typical value for ammonia reagent SCR system - Equation 2.13
q_{fuel}	9190	ft^3/min-MMBtu/hr, base case flue gas volumetric flow rate factor, used O_2 F-Factors from 12/12/2018 testing
base case T	932.6	Fahrenheit, observed during 12/12/2018 testing
$q_{fluegas}$	5402509	acfm, Average gas stream volumetric flow from three runs conducted 12/12/2018
η_{adj}	1.2391	Equation 2.23
NO_{Xadj}	1.07054	Equation 2.25
$Slip_{adj}$	1.17010	Equation 2.24, Slip=5 ppm (chosen for higher temperature operation)
N_{SCR}	1	Number of SCR Reactors
$Temperature_{adj}$	2.2745	Equation 2.27
$Vol_{catalyst}$	8313.20	ft^3 - Equation 2.22

System Parameter	Value	Units / Description
$A_{catalyst}$	5627.61	ft^2, catalyst cross-sectional area - Equation 2.28 (Uses 16 ft/sec as superficial velocity)
A_{SCR}	6471.76	ft^2, SCR reactor cross-sectional area - Equation 2.29
length and width	80.45	ft, for a Square reactor - Equation 2.30
h'_{layer}	3.1	ft, nominal height for each catalyst layer, Footnote 23
n_{layer}	0.477	number of catalyst layers
$n_{layer, revised}$	2	Minimum number of layers (Rounded to nearest integer [1] but there must be at least two catalyst layers)
h_{layer}	1.739	ft, Equation 2.32
M_{NOx}	46.01	lb/mole, Molecular Weight of NO2
$M_{reagent}$	17.03	lb/mole, MW of ammonia reagent
$\dot{m}_{reagent}$	199.318	lb/hr, mass flow rate of reagent - Equation 2.35
C_{sol}	0.19	Weight Fraction of aqueous ammonia reagent solution, 19% from facility proposal
$\dot{m}_{sol}$	1049.044	lb/hr, mass flow rate of aqueous reagent solution, Equation 2.36
ρ_{sol}	7.74	lb/gal, density of aqueous reagent solution for 19% solution ammonia at 60°F
q_{sol}	135.535	gal/hr, solution volume flow rate, Equation 2.35
$Cost_{reag}$	0.451	$/lb of aqueous ammonia, Site Reported Data
P_0	14.7	psi, atmospheric pressure at sea level
h	12	feet, elevation of unit
P_{ELEV}	14.703	Equation 2.39b
ELEVF	0.9998	Equation 2.39a
Retrofit Factor	1	Value for "average difficulty"
TCI	**$ 8,402,128.36**	**$, Equation 2.45 (Utility, Oil- and Gas-fired units ≥25 MW to 500 MW)**
Annual Maintenance Cost	$ 42,010.64	$, Equation 2.57
Annual Reagent Cost	$ 621,677.95	$, Equation 2.58
P	369.6	kW, electrical power consumption of SCR system, Equation 2.60
$Cost_{elect}$	$ 188.26	$/MW, Site Reported Data
Annual Electricity Cost	$ 91,429.30	$, Equation 2.62
$CC_{replace}$	$ 227.00	$/ft³, default value for Catalyst Cost, includes removal and disposal/regeneration and installation
Catalyst Replacement Cost	$ 943,548.04	$, Equation 2.63 where $R_{layer}=n_{layer}$ for replacing 1 layer at a time
i	10%	Interest [SEE **FOOTNOTE 2**]
Y	5	years, catalyst life for site average capacity factor, Site Reported Data

System Parameter	Value	Units / Description
Future Worth Factor	0.1638	Equation 2.65
Annual Catalyst Replacement Cost	$ 154,550.79	Equation 2.64
Direct Annual Costs	**$ 909,668.68**	**$, Equation 2.56**
Operator Labor Rate	$ 73.80	$/hr, Site Reported Data
Annual Operator Labor Cost	$ 96,973.20	$, with 15% Capacity Factor
Administrative Charges	$ 3,413.32	$, Equation 2.69
Capital Recovery Factor	0.11746	Equation 2.71, where i=10%, n=20 years [Site Data]. Equipment originally commissioned in 1974, 20 years provided by facility. [SEE **FOOTNOTE 2**]
Capital Recovery	$ 986,910.84	$, Equation 2.70
Indirect Annual Cost	**$ 990,324.17**	**$, Equation 2.68**
Total Annual Cost	**$ 1,899,992.85**	**$, Equation 2.72**
Cost Effectiveness	**$ 5,638.86**	**$/ton of NO_X Removed**

The below cost analysis examines the application of Water Injection (WI) on both of the two GE Frame 7B Simple Cycle Combustion Turbine engines located at the Exelon Generation Company – Richmond Generating Station's facility located at 3901 North Delaware Avenue, Philadelphia PA 19137. Primary Source: EPA Air Pollution Cost Control Manual, Section 1 - Introduction, Chapter 2 – Cost Estimation, last updated February 1, 2018.

Table 4: Cost Analysis for Water Injection

Parameter	Value	Factor	Basis
Total Capital Cost			
Direct Costs			
Buildings	$0		None Needed
Purchased Equipment:	$3,344,690.00		
(2) Water Injection System GE Supply	$1,768,550.00		GE Proposal: 2 * ($16,605 Revise Control Curve + $867,670 Water Injection System)
Laser Scan Survey (total for all units)	$113,200.00		GE Proposal (Price per site)
(2) GE Mark Vie controls upgrade	$800,000.00		GE Proposal: 10/7/2016 budgetary price. Required for GE to incorporate WI control program and associated combustor tuning.
(2) NOx analyzers	$100,000.00	$ 50,000	Facility Estimate
(1) On-site Monitoring Lite instrumentation	$12,940.00		GE Proposal (Price to monitor three turbines or fewer)
(2) 550,000 gallon demineralized water storage tanks & pumps	$550,000.00		Facility Estimate

Parameter	Value	Factor	Basis
Purchased Equipment Cost (PEC)	$3,511,924.50		Purchased Equipment + Freight Cost
Freight	$167,234.50	5%	5% of Purchased Equipment (Typical Value from EPA Cost Control Manual [CCM], Table 2.4 on Page 2-26)
Site Preparation	$351,192.45	10%	10% of PEC, including relocation of interferences
Direct Installation Cost	$1,404,769.80		
Foundations & Supports	$280,953.96	8%	8% of Purchased Equipment Cost
Handling & Erection	$702,384.90	20%	20% of Purchased Equipment Cost
Electrical	$140,476.98	4%	MCC, wiring, control dashboards
Piping	$70,238.49	2%	All including recirculation except from Vendor
Insulation, Heat tracing	$140,476.98	4%	4% of Purchased Equipment Cost
Painting	$70,238.49	2%	2% of Purchased Equipment Cost
Total Direct Cost (TDC)	**$5,267,886.75**		
Indirect Costs			
Engineering & Project Management	$351,192.45	10%	10% of Purchased Equipment Cost
Construction & Field Expenses	$175,596.23	5%	5% of Purchased Equipment Cost
Contractor Fees	$351,192.45	10%	10% of Purchased Equipment Cost
Start-up	$70,238.49	2%	2% of Purchased Equipment Cost
Performance Test	$10,000.00		Estimate including initial RATA
Contingencies	$702,384.90	20%	20% of PEC, EPA CCM 2.6.4.2
Interest During Construction	$247,590.68		TDC * 4.7% interest rate [Site Data] * 1 years
Total Indirect Cost (TIC)	**$1,908,195.19**		
Total Capital Investment Cost (TCI)	**$7,176,081.94**		
Total Annual Cost			
Direct Annual Costs			
Utilities Cost	$23,812.11	$ 188.26	$188.257 $/MW-hr [Site Data, See **FOOTNOTE 1**]
Power Consumption for Pumps	83	MW-hr/yr	2 * 42.5 HP pumps [15-65 psig water injection, full load injection at 110 gpm, Combustor showerhead pressure 200 psig] * 15% CF * 8760 hrs/yr / 1341.022 HP/MW
Power Consumption for Heater	43	MW-hr/yr	2 * 30 kW heater * 720 hrs/yr [6 hrs/day for 4 months/yr] / 1000 kW/MW
Demineralized Water Cost	$112,241.44	$13/1000 gal	2* 27400 lb/hr (GE Data) * 15% * 8760 hrs/yr / 8.34 lbs/gal * $13/1000 $/gal

Parameter	Value	Factor	Basis
Labor Cost	$137,387.01		
Maintenance Labor	$3,838.00	52	52 hrs/yr @ $73.80/hr (Facility Estimate)
Operating Labor	$110,700.00	1500	1500 hrs/yr @ $73.80/hr (Facility Estimate)
Supervisory Labor	$12,849.01	10%	10% of O&M hours (1500+52) @ $82.79/hr
Annual Testing	$10,000.00		Estimate including RATA
Maintenance Material Cost	$3,838.00		EPA CCM 2.6.5.3: "a factor of 100% of the maintenance labor cost"
Annual Inspection Cost	$24,333.00		$73,000 for entire site for 3 years, 73000/3=24333 (Facility Estimate)
Fuel Penalty Cost	$499,495.76		Additional fuel cost for compensating higher heat rate. Additional Fuel Req * Fuel Cost
Net Estimated heat rate increase		2%	Vendor (GE) communication
Total Annual Heat Input	2202264	MMBtu/ year	838 MMBtu/hr * 2 units * 15% CF * 8760 hrs/yr
Additional Heat Input	44045.28	MMBtu/ year	2% Increase * 2202264 MMBtu/yr
Fuel Oil Heating Value	137560	Btu/gallon	Station TV Permit Data
Additional Fuel Requirement	320189.59	gallon/ year	Additional Heat Input / Heating Value * 1000000
Delivered cost of fuel oil at site	$1.56	$/gal	Site Data: Ref John Tissue email dated 10/10/2016
Total Direct Annual Cost	**$801,107.31**		
Indirect Annual Cost			
Overhead	$78,735.00	60%	60% of "labor (operating, supervisory, and maintenance) plus maintenance materials", EPA CCM 2.6.5.7
Administrative Charge	$143,521.64	2%	2% of TCI, EPA CCM 2.6.5.8
Insurance	$71,760.82	1%	1% of TCI, EPA CCM 2.6.5.8
Capital Recovery	$842,899.89		CR = CRF * TCI
Capital Recovery Factor	0.11746	10%	[i(1+i)^n] / {[(1+i)^n]-1}, where i=10%, n=20 years [Site Data]. Equipment originally commissioned in 1974, 20 years provided by facility. [SEE **FOOTNOTE 2**]
Total Indirect Annual Cost	**$1,136,917.36**		
Total Annual Operating Costs	**$1,938,024.67**		

Parameter	Value	Factor	Basis
Baseline NO_X Emissions (TPY)	749		NO_X emissions for both CTs based on NO_X emission rate of 0.68 lb/MMBtu (176 ppmv) and 15% CF
Post-Control NO_X Emissions (TPY)	383		NO_X emissions for both CTs based on NO_X emission rate of 0.348 lb/MMBtu (90 ppmvd) and 15% CF [SEE **FOOTNOTE 3**]
NO_X Emission Reduction (TPY)	366		Baseline - Post Control NO_X Emissions
Cost Effectiveness ($/ton NO_X removed)	**$5,301.29**		

1: "The Exelon analysis uses a value that reflects Richmond's cost rather than the grid average price. Oil fired simple cycle combustion turbines have much higher costs (e.g. based on fuel alone, without consideration other costs) than the average grid price, which is why the unit operates with such a very low capacity factor. Exelon continues to support use of 188.257 $/MW-hr."

2: Exelon uses i=10% "The rate of 10% is consistent with Exelon's proprietary firm specific rate, which reflects a weighted average cost of capital that incorporates a combination equity and debt financing." This is backed up by Exelon data confirmed by AMS through correspondence dated February 2020. Furthermore, AMS found that setting i=5% did not bring the Cost Effectiveness to below the threshold considered for economic reasonability.

3: "Per vendor data included with submitted RACT analysis, this control technology can achieve a rate of 90 ppm... Based on conversations with a GE representative, 42 ppm has not been demonstrated on this vintage combustion turbine firing oil. The information referenced on GE's website, may have been primarily intend for new or aeroderivative units, as indicated by statement "Applicable Turbine Models LM2500, LM6000, LMS100", viewed by clicking on the Product Details link of the GE website at https://www.ge.com/power/services/gas-turbines/upgrades/water-injection-for-nox-reduction. Achieving a rate near 42 ppm, would require significant engineering design and capital changes that would significantly increase the costs and would not be guaranteed until proven in the field. For example, additional capital consideration would include: water tanks, additional piping, water forwarding and injection skid, demineralization system, enhanced technology fuel nozzles, fuel purge system, re-piping combustion enclosure, and updated controls systems."