Constellation

December 28, 2022

Via Electronic Mail
Mr. James Rebarchak
Regional Air Program Manager
PA Department of Environmental Protection
Bureau of Air Quality
Southeast Regional Office
2 East Main Street
Norristown, PA 19401

Dear Mr. Rebarchak:

Subject: RACT III Case-by-Case Analysis Update
Constellation Energy Generation, LLC
Croydon Generating Station
Title V Operating Permit No. 09-00016

Constellation Energy Generation, LLC (Constellation) is submitting this proposal to demonstrate compliance with the Reasonably Available Control Technology (RACT) requirements of 25 Pa. Code Sections §129.111 through §129.115 for their Croydon Generating Station (Croydon) located in Bristol Township, Bucks County, Pennsylvania. The following proposal includes background information, a facility description, a summary of RACT affected sources and an updated limited case-by-case analysis per the requirements of §129.114(i) for sources that do not meet the presumptive RACT requirements of §129.112.

1.0 BACKGROUND AND FACILITY DESCRIPTION

On November 12, 2022, the Pennsylvania Department of Environmental Protection (PADEP) finalized amendments to 25 Pa. Code Chapters 121 (§121.1 relating to definitions) and 129 (§129.111 - §129.115), Additional RACT Requirements for Major Sources of NOx and VOCs for the 2015 Ozone NAAQS (known as RACT III). The requirements of 25 Pa. Code §129.111 - §129.115 apply to owners and operators of all facilities in Pennsylvania that emit or have the potential to emit greater than 100 tons per year (tpy) of NOx and/or 50 tpy of VOCs.

An owner or operator subject to RACT III has three compliance options as follows:

1. Compliance with presumptive RACT requirements and/emissions limits of §129.112;

2. Facility-wide or system-wide averaging for compliance with presumptive NOx emissions limits per §129.113; or

3. Case-by-case RACT determinations for sources that either do not have an applicable presumptive requirements or emissions limitation or cannot comply with the applicable presumptive RACT requirement per §129.114. If a source was previously subject to a

RACT II case-by-case determination, and that source has not been modified or changed, the facility may, in lieu of doing another full case-by-case proposal for RACT III, submit a limited analysis as specified in §129.114(i).

The Croydon Generating Station is located at 955 River Road in Bristol Township, Bucks County, Pennsylvania. The station consists of eight (8) distillate oil and/or kerosene-fired General Electric Frame 7B combustion turbine-generator units nominally rated at 64 megawatts (MW) each and were commissioned in 1974 (Simple Cycle Turbines 11, 12, 21, 22, 31, 32, 41 and 42). The units are operated in accordance with Title V Operating Permit 09-00016 issued by PADEP on December 10, 2019. The facility is considered a major source of NOx emissions; therefore, these combustion units must demonstrate compliance with RACT III requirements for sources of NOx emissions.

2.0 RACT AFFECTED SOURCES

Per 25 Pa. Code §129.111 and 129.115(a), an owner and operator of an air contamination source subject to the RACT III regulations must submit a notification describing how the facility intends to comply with the RACT III requirements and other information identified in 25 Pa. Code §129.115(a).

On December 28, 2022, Constellation submitted the required written notification of their plan to demonstrate compliance with the RACT III requirements for Croydon. A copy of the written notification is included as Attachment A.

The following table (Table 1-1) illustrates the sources at Croydon subject to RACT III and the method used for demonstrating compliance with the RACT III requirements.

Table 1-1: Description of RACT Affected Units

Source ID	Source Description	Capacity	Fuel	RACT III Compliance Method
031	Simple Cycle Turbine #11	5,940 gal/hr	No. 2 fuel oil	Case-by-case RACT – does not meet presumptive RACT emission limit of 96 ppmvd NOx at 15% oxygen for combustion turbines firing fuel oil per §129.112(g)
032	Simple Cycle Turbine #12	5,940 gal/hr	No. 2 fuel oil	Case-by-case RACT – does not meet presumptive RACT emission limit of 96 ppmvd NOx at 15% oxygen for combustion turbines firing fuel oil per §129.112(g)
033	Simple Cycle Turbine #21	5,940 gal/hr	No. 2 fuel oil	Case-by-case RACT – does not meet presumptive RACT emission limit of 96 ppmvd NOx at 15% oxygen for combustion turbines firing fuel oil per §129.112(g)
034	Simple Cycle Turbine #22	5,940 gal/hr	No. 2 fuel oil	Case-by-case RACT – does not meet presumptive RACT emission limit of 96 ppmvd NOx at 15% oxygen for combustion turbines firing fuel oil per §129.112(g)

Source ID	Source Description	Capacity	Fuel	RACT III Compliance Method
035	Simple Cycle Turbine #31	5,940 gal/hr	No. 2 fuel oil	Case-by-case RACT – does not meet presumptive RACT emission limit of 96 ppmvd NOx at 15% oxygen for combustion turbines firing fuel oil per §129.112(g)
036A	Simple Cycle Turbine #32	5,940 gal/hr	No. 2 fuel oil	Case-by-case RACT – does not meet presumptive RACT emission limit of 96 ppmvd NOx at 15% oxygen for combustion turbines firing fuel oil per §129.112(g)
037	Simple Cycle Turbine #41	5,940 gal/hr	No. 2 fuel oil	Case-by-case RACT – does not meet presumptive RACT emission limit of 96 ppmvd NOx at 15% oxygen for combustion turbines firing fuel oil per §129.112(g)
038	Simple Cycle Turbine #42	5,940 gal/hr	No. 2 fuel oil	Case-by-case RACT – does not meet presumptive RACT emission limit of 96 ppmvd NOx at 15% oxygen for combustion turbines firing fuel oil per §129.112(g)

Croydon previously demonstrated compliance with the requirements of 25 Pa. Code Chapter 129 (§129.96 - §129.100) "Additional RACT Requirements for Major Sources of NOx and VOCs" (known as RACT II) for the combustion sources located at the facility. PADEP approved an alternative RACT II proposal for the eight combustion turbines located at Croydon. The RACT II requirements have been incorporated into the facility's Title V Operating Permit and are, therefore, federally enforceable.

The eight combustion turbines located at Croydon have not been modified since the approved case-by-case RACT II proposal; therefore, Constellation is submitting the following limited case-by-case RACT analysis per §129.114(i) to demonstrate compliance with RACT III.

3.0 LIMITED CASE-BY-CASE RACT ANALYSIS

According to §129.114(i), if a source was previously subject to a RACT II case-by-case determination, and that source has not been modified or changed, the facility may, in lieu of doing another full case-by-case proposal for RACT III, submit to the Department a limited analysis certified by the responsible official.

Croydon previously demonstrated compliance with RACT II for the eight combustion turbines with a case-by-case analysis approved by PADEP. The RACT II requirements have been incorporated into the facility's Title V Operating Permit. The combustion turbines have not been modified since the RACT II analysis was completed and approved by the Department.

A copy of the case-by-case analysis completed to demonstrate compliance with RACT II for the combustion turbines is included in Attachment B. The analysis considered the technical and economic feasibility of the following control technologies:

- Water Injection
- Fuel Switching
- Selective Catalytic Reduction (SCR)
- Dry Low NOx Combustors

The analysis concluded that the only technologies technically feasible for the combustion turbines are water injection and SCR. Croydon performed an economic analysis for these control options. As shown in Table 5-1 of the analysis, the cost effectiveness was calculated to be $6,103 and $8,531 per ton NOx removed for water injection and SCR, respectively. Based on the presumptive RACT II benchmark of $3,500 per ton NOx removed, the cost analysis showed that both water injection and SCR were not cost effective for the combustion turbines at Croydon.

The eight combustion turbines at Croydon have not been modified since the approved case-by-case RACT II proposal; therefore, Constellation is submitting the following limited case-by-case RACT analysis per §129.114(i) to demonstrate compliance with RACT III. Because the RACT II analysis showed a cost effectiveness greater than $7,500 per ton of NOx emissions removed for SCR, Constellation may submit a limited case-by-case RACT analysis including the information required by §129.114(i)(1)(i) for this control option. For water injection, because the RACT II analysis showed a cost effectiveness less than $7,500 per ton of NOx emissions removed, Constellation may submit a limited case-by-case RACT analysis including the information required by §129.114(i)(1)(ii), which includes an updated economic feasibility analysis for this control option.

To demonstrate compliance with RACT III for SCR for the eight combustion turbines, Constellation is submitting this limited case-by-case RACT analysis. The following lists the information required by §129.114(i)(1)(i):

- *§129.114(i)(1)(i)(A): A statement that explains how the owner or operator determined that there is no new pollutant specific air cleaning device, air pollution control technology or technique available.*

  Constellation Response: Croydon consists of eight (8) distillate oil and/or kerosene-fired General Electric Frame 7B combustion turbine-generator units nominally rated at 64 MW each and were commissioned in 1974.

  The principal nitrogen pollutants generated by combustion turbines are nitric oxide (NO) and nitrogen dioxide (NO_2), collectively known as NOx. NOx is primarily formed by two mechanisms in the combustion turbine combustor. The first and primary mechanism is the fixation of atmospheric nitrogen during the combustion process and the resultant pollutant is referred to as thermal NOx. The second mechanism is the conversion of the fuel bound nitrogen to NOx in the presence of excess air during the combustion process.

  Available combustion turbine control technologies are common and widely known. The technology screening was based on unit specific information obtained from the manufacturer, General Electric, and site engineers at Croydon. The control options were evaluated based on process demonstrability, commercial availability, technical compatibility with the combustion turbine equipment and compatibility with the existing plant systems. Control options that did not meet this criteria were eliminated and were not considered in the cost evaluation phase. No new control technologies have been developed since the RACT II analysis was completed.

- *§129.114(i)(1)(i)(B): A list of the technically feasible air cleaning devices, air pollution control technologies or techniques previously identified and evaluated under §129.92(b)(1)—(3) included in the written RACT proposal submitted under §129.99(d) and approved by the Department or appropriate approved local air pollution control agency under §129.99(e).*

  Constellation Response: The RACT II analysis concluded that water injection and SCR passed the technology screening for Croydon. Fuel switching failed due the lack of a gas supply line in the vicinity of the station. Dry low NOx combustors were dropped from the analysis because General Electric has not developed a dry low NOx burner retrofit for firing distillate fuel for this model turbine. Based on the results of the technology screening, water injection and SCR were included in the cost evaluation.

- *§129.114(i)(1)(i)(C): A summary of the economic feasibility analysis performed for each technically feasible air cleaning device, air pollution control technology or technique listed in clause (B) and the cost effectiveness of each technically feasible air cleaning device, air pollution control technology or technique as submitted previously under §129.99(d) or as calculated consistent with the ''EPA Air Pollution Control Cost Manual'' (6th Edition), EPA/452/B- 02-001, January 2002, as amended.*

  Constellation Response: The RACT II analysis concluded that the only technologies technically feasible for Croydon's combustion turbines are water injection and SCR. Croydon performed an economic analysis for these control options. The analysis is included in Attachment B. As shown in Table 5-1 of the analysis, the cost effectiveness was calculated to be $6,103 and $8,531 per ton NOx removed for water injection and SCR, respectively. Based on the presumptive RACT II benchmark of $3,500 per ton NOx removed, the cost analysis showed that both water injection and SCR were not cost effective for the combustion turbines at Croydon.

- *§129.114(i)(1)(i)(D): A statement that an evaluation of each economic feasibility analysis summarized in clause (C) demonstrates that the cost effectiveness remains equal to or greater than $7,500 per ton of NOx emissions reduced.*

  Constellation Response: The economic feasibility analysis showed that the cost effectiveness of SCR is greater than $7,500 per ton of NOx emissions reduced.

  The cost evaluation was developed in accordance with the methodology outlined in USEPA's OAQPS Control Cost Manual. Capital costs for major equipment were estimated based on information from equipment suppliers. Costs such as those for foundations and supports, handling and erection, piping and indirect costs such as engineering, construction and field expenses were estimated as percentage of purchased equipment cost as per OAQPS methodology and site-specific conditions. Operating and maintenance costs are a constituent of the total compliance cost over the life of the plant and are needed to project the levelized life cycle compliance cost. Details of the methodology are included in Attachment B.

The OAQPS Control Cost Manual has not been updated since the RACT II analysis was completed. In addition, based on discussions with vendors and inflation, the costs of materials and labor have increased since the RACT II analysis. Based on the expected increase in material and labor costs, the cost effectiveness of SCR remains greater than $7,500 per ton of NOx emissions reduced.

To demonstrate compliance with RACT III for water injection for the eight combustion turbines, Constellation is submitting this limited case-by-case RACT analysis. The following lists the information required by §129.114(i)(1)(ii):

- *§129.114(i)(1)(ii)(A): A statement that explains how the owner or operator determined that there is no new pollutant specific air cleaning device, air pollution control technology or technique available.*

  Constellation Response: Croydon consists of eight (8) distillate oil and/or kerosene-fired General Electric Frame 7B combustion turbine-generator units nominally rated at 64 MW each and were commissioned in 1974.

  The principal nitrogen pollutants generated by combustion turbines are nitric oxide (NO) and nitrogen dioxide (NO_2), collectively known as NOx. NOx is primarily formed by two mechanisms in the combustion turbine combustor. The first and primary mechanism is the fixation of atmospheric nitrogen during the combustion process and the resultant pollutant is referred to as thermal NOx. The second mechanism is the conversion of the fuel bound nitrogen to NOx in the presence of excess air during the combustion process.

  Available combustion turbine control technologies are common and widely known. The technology screening was based on unit specific information obtained from the manufacturer, General Electric, and site engineers at Croydon. The control options were evaluated based on process demonstrability, commercial availability, technical compatibility with the combustion turbine equipment and compatibility with the existing plant systems. Control options that did not meet this criteria were eliminated and were not considered in the cost evaluation phase. No new control technologies have been developed since the RACT II analysis was completed.

- *§129.114(i)(1)(ii)(B): A list of the technically feasible air cleaning devices, air pollution control technologies or techniques previously identified and evaluated under §129.92(b)(1)—(3) included in the written RACT proposal submitted under §129.99(d) and approved by the Department or appropriate approved local air pollution control agency under §129.99(e).*

  Constellation Response: The RACT II analysis concluded that water injection and SCR passed the technology screening for Croydon. Fuel switching failed due the lack of a gas supply line in the vicinity of the station. Dry low NOx combustors were dropped from the analysis because General Electric has not developed a dry low NOx burner retrofit for firing distillate fuel for this model turbine. Based on the results of the technology screening, water injection and SCR were included in the cost evaluation.

- *§129.114(i)(1)(ii)(C): A summary of the economic feasibility analysis performed for each technically feasible air cleaning device, air pollution control technology or technique listed in clause (B) and the cost effectiveness of each technically feasible air cleaning device, air pollution control technology or technique as submitted previously under §129.99(d) or as calculated consistent with the ''EPA Air Pollution Control Cost Manual'' (6th Edition), EPA/452/B- 02-001, January 2002, as amended.*

  Constellation Response: The RACT II analysis concluded that the only technologies technically feasible for Croydon's combustion turbines are water injection and SCR. Croydon performed an economic analysis for these control options. The analysis is included in Attachment B. As shown in Table 5-1 of the analysis, the cost effectiveness was calculated to be $6,103 and $8,531 per ton NOx removed for water injection and SCR, respectively. Based on the presumptive RACT II benchmark of $3,500 per ton NOx removed, the cost analysis showed that both water injection and SCR were not cost effective for the combustion turbines at Croydon.

- *§129.114(i)(1)(ii)(D): A statement that an evaluation of each economic feasibility analysis summarized in clause (C) demonstrates that the cost effectiveness remains less than $7,500 per ton of NOx emissions reduced.*

  Constellation Response: The economic feasibility analysis showed that the cost effectiveness of water injection is less than $7,500 per ton of NOx emissions reduced.

  The cost evaluation was developed in accordance with the methodology outlined in USEPA's OAQPS Control Cost Manual. Capital costs for major equipment were estimated based on information from equipment suppliers. Costs such as those for foundations and supports, handling and erection, piping and indirect costs such as engineering, construction and field expenses were estimated as percentage of purchased equipment cost as per OAQPS methodology and site-specific conditions. Operating and maintenance costs are a constituent of the total compliance cost over the life of the plant and are needed to project the levelized life cycle compliance cost. Details of the methodology are included in Attachment B.

  Constellation performed an updated evaluation of cost effectiveness for water injection in accordance with the methodology outlined in USEPA's OAQPS Control Cost Manual and updated material and labor costs provided by the combustion turbine vendor (General Electric). The updated economic analysis including is included in Attachment C. The updated evaluation shows a cost effectiveness of $9,267 per ton NOx reduced, which increased to greater than $7,500 per ton of NOx reduced.

- *§129.114(i)(1)(ii)(E): A new economic feasibility analysis for each technically feasible air cleaning device, air pollution control technology or technique listed in clause (B) in accordance with §129.92(b)(4).*

Constellation Response: Constellation performed an updated evaluation of cost effectiveness for water injection in accordance with the methodology outlined in USEPA's OAQPS Control Cost Manual and updated material and labor costs provided by the combustion turbine vendor (General Electric). The economic analysis along with vendor data used in the analysis is presented Attachment C, which includes the following tables:

- Table C-1 – Summary of Results
- Table C-2 – Basis for Calculations
- Table C-3 – Capital Costs
- Table C-4 – Operating and Annualized Costs
- Table C-5 – Supporting Calculations

As shown in Table C-1 of the economic analysis, the cost effectiveness to add water injection to Croydon's combustion turbines is $9,267 per ton NOx reduced. According to the Preamble of RACT III, the cost-effectiveness benchmark for presumptive NOx RACT is $3,750/ton NOx. Based on this benchmark, Constellation submits that the addition of water injection is cost prohibitive.

4.0 RACT PROPOSAL AND CONCLUSION

Based on the technology screening analysis and economic analysis completed, there are no add-on NOx control technologies that are technologically feasible or cost effective for the combustion turbines at Croydon. The baseline NOx emissions show that the units do not meet the presumptive RACT requirements or emissions limits specified in RACT II. Because the units do not meet the presumptive RACT emission limits, Constellation has prepared this case-by-case RACT proposal in accordance with the requirements of 25 Pennsylvania Code §129.114(i)(1) for approval by the PADEP.

Based on the completed analysis, Constellation is submitting the following proposal to demonstrate compliance with RACT III:

- Emission and Operating Restrictions: To comply with RACT III, the facility will continue to comply with the following NOx emission and fuel restrictions as previously incorporated into the facility's Title V Operating Permit:

Permit Limits	Value
Facility-Wide NOx (Tons/yr)	1,296
Max. NOx (per turbine) (Lbs/MMBtu)	0.7
Max. NOx (per turbine) (Lbs/hr)	587
Capacity Factor	20%

- Testing Requirements: Constellation will demonstrate compliance with the proposed NOx RACT emission limitation with source testing in accordance with the terms and conditions of the facility's existing Title V Operating Permit. Constellation will test for the NOx emissions in lbs/MMBtu and lbs/hr in accordance with the provisions of

25 Pennsylvania Code §129 and 145. Constellation shall perform the testing on three of the eight turbines at least once per permit term and all eight of the turbines at least once every three permit terms.

- Monitoring, Recordkeeping and Reporting Requirements: Constellation will continue to comply with the monitoring, recordkeeping and reporting requirements in accordance with the facility's existing Title V Operating Permit. Constellation will record monthly fuel consumption, monthly electrical power generated, monthly and twelve-month rolling capacity factor for each turbine and monthly NOx emissions calculated using the most recent stack test results. The facility will also maintain records of the emissions tests conducted on the turbines. NOx emissions will be reported annually in the facility's annual emissions report submitted to the PADEP.

As required by §129.114(i), a certification of the RACT III analysis by the responsible official is included in Attachment D.

Please contact Albert M. Hatton III at 610-213-9958 or Albert.Hatton@constellation.com if you have any questions or require additional information.

Very truly yours,

Joseph Dick
General Manager

ATTACHMENT A

WRITTEN NOTIFICATION FORM

December 28, 2022

Via Electronic Mail
Mr. James Rebarchak
Regional Air Program Manager
PA Department of Environmental Protection
Bureau of Air Quality
Southeast Regional Office
2 East Main Street
Norristown, PA 19401

Dear Mr. Rebarchak:

Subject: RACT III Notification
Constellation Energy Generation, LLC
Croydon Generating Station
Title V Operating Permit No. 09-00016

Constellation Energy Generation, LLC (Constellation) is submitting this written notification of their plan to demonstrate compliance with the Reasonably Available Control Technology (RACT) requirements of 25 Pa. Code Sections §129.111 through §129.115 for their Croydon Generating Station (Croydon) located in Bristol Township, Bucks County, Pennsylvania.

On November 12, 2022, the Pennsylvania Department of Environmental Protection (PADEP) finalized amendments to 25 Pa. Code Chapters 121 (§121.1 relating to definitions) and 129 (§129.111 - §129.115), Additional RACT Requirements for Major Sources of NOx and VOCs for the 2015 Ozone NAAQS (known as RACT III). The requirements of 25 Pa. Code §129.111 - §129.115 apply to owners and operators of all facilities in Pennsylvania that emit or have the potential to emit greater than 100 tons per year (tpy) of NOx and/or 50 tpy of VOCs. Per 25 Pa. Code §129.111 and 129.115(a), an owner and operator of an air contamination source subject to the RACT III regulations must submit a notification describing how the facility intends to comply with the RACT III requirements and other information identified in 25 Pa. Code §129.115(a).

The Croydon Generating Station is located at 955 River Road in Bristol Township, Bucks County, Pennsylvania. The station consists of eight (8) General Electric Frame 7B combustion turbine-generator units nominally rated at 64 megawatts (MW) each fired on No. 2 fuel oil and/or kerosene and were commissioned in 1974 (Simple Cycle Turbines 11, 12, 21, 22, 31, 32, 41 and 42). The units are operated in accordance with Title V Operating Permit 09-00016 issued by PADEP on December 10, 2019. The facility is considered a major source of NOx emissions; therefore, these combustion units must demonstrate compliance with RACT III requirements. As such, Croydon is submitting this RACT III notification.

The attached RACT III written notification template as provided by the PADEP details how Croydon intends to comply with RACT III. The attached form provides the information required by §129.115(a). In summary, Constellation will submit a limited case-by-case RACT analysis per the requirements of §129.114(i) to demonstrate compliance with RACT III for the eight combustion turbines located at Croydon.

Please contact Albert M. Hatton III at 610-213-9958 or Albert.Hatton@constellation.com if you have any questions or require additional information.

Very truly yours,

Joseph Dick
General Manager

CHAPTER 129. STANDARDS FOR SOURCES ADDITIONAL RACT REQUIREMENTS FOR MAJOR SOURCES OF NOx AND VOCs FOR THE 2015 OZONE NAAQS

Written notification, 25 Pa. Code §§129.111 and 129.115(a)

25 Pa. Code Sections 129.111 and129.115(a) require that the owner and operator of an air contamination source subject to the final-form RACT III regulations submit a notification describing how you intend to comply with the final-form RACT III requirements, and other information spelled out in subsection 129.115(a). The owner or operator may use this template to notify DEP. Notification must be submitted in writing or electronically to the appropriate Regional Manager located at the appropriate DEP regional office. In addition to the notification required by §§ 129.111 and 129.115(a), you also need to submit an applicable analysis or RACT determination as per § 129.114(a) or (i).

Is the facility major for NOx?	**Yes** ☒ **No** ☐
Is the facility major for VOC?	**Yes** ☐ **No** ☒

FACILITY INFORMATION					
Facility Name	Croydon Generating Station				
Permit Number	09-00016	**PF ID if known**			
Address Line1	955 River Road				
Address Line2	Bristol Township				
City		**State**	PA	**Zip**	19020
Municipality	Bristol Township		**County**	Bucks	
OWNER INFORMATION					
Owner	Constellation Energy Generation, LLC				
Address Line1	200 Exelon Way				
Address Line2					
City	Kennett Square	**State**	PA	**Zip**	19348
Email	Albert.Hatton@constellation.com		Phone	610 213 9958	
CONTACT INFORMATION					
Permit Contact Name	Albert M. Hatton III				
Permit Contact Title	Manager, Environmental Programs				
Address Line	200 Exelon Way				
City	Kennett Square	**State**	PA	**Zip**	19348
Email	Albert.Hatton@constellation.com		Phone	610 213 9958	

Complete Table 1, including all air contamination sources that commenced operation on or before August 3rd, 2018. Air contamination sources determined to be exempt from permitting requirements also must be included. You may find this information in section A and H of your operating permit.

Table 1 - Source Information

Source ID	Source Name	Make	Model	Physical location of a source (i.e, building#, plant#, etc.)	Was this source subject to RACT II?
031	Simple Cycle Turbine #11	General Electric Co.	MS7001B/7B	Main Plant	Yes
032	Simple Cycle Turbine #12	General Electric Co.	MS7001B/7B	Main Plant	Yes
033	Simple Cycle Turbine #21	General Electric Co.	MS7001B/7B	Main Plant	Yes
034	Simple Cycle Turbine #22	General Electric Co.	MS7001B/7B	Main Plant	Yes
035	Simple Cycle Turbine #31	General Electric Co.	MS7001B/7B	Main Plant	Yes
036A	Simple Cycle Turbine #32	General Electric Co.	MS7001B/7B	Main Plant	Yes
037	Simple Cycle Turbine #41	General Electric Co.	MS7001B/7B	Main Plant	Yes
038	Simple Cycle Turbine #42	General Electric Co.	MS7001B/7B	Main Plant	Yes

Complete Table 2 or 3 if the facility is a major NOx or VOC emitting facility. For the column with the title "How do you intend to comply", compliance options are:

- Presumptive RACT requirement under §129.112 (**PRES**),
- Facility-wide averaging (**FAC**) §129.113,
- System-wide averaging (**SYS**) §129.113, or
- Case by case determination §129.114 (**CbC**).

Please provide the applicable subsection if source will comply with the presumptive requirement under §129.112.

Table 2 – Method of RACT III Compliance, NOx

Source ID	Source Name	NOx PTE TPY	Exempt from RACT III (yes or no)	How do you intend to comply? (PRES, CbC, FAC or SYS)	Specific citation of rule if presumptive option is chosen
031	Simple Cycle Turbine #11	637.42	No	CbC	
032	Simple Cycle Turbine #12	637.42	No	CbC	
033	Simple Cycle Turbine #21	500.06	No	CbC	
034	Simple Cycle Turbine #22	637.42	No	CbC	
035	Simple Cycle Turbine #31	637.42	No	CbC	
036A	Simple Cycle Turbine #32	400.05	No	CbC	
037	Simple Cycle Turbine #41	637.42	No	CbC	
038	Simple Cycle Turbine #42	400.05	No	CbC	

Please complete Table 3 if the facility is a major VOC emitting facility. Please provide the applicable section if a source is complying with any RACT regulation listed in 25 Pa Code §§ 129.51, 129.52(a)—(k) and Table I categories 1—11, 129.52a—129.52e, 129.54—129.63a, 129.64—129.69, 129.71—129.73, 129.75 129.71—129.75, 129.77 and 129.101—129.107.

Table 3 – Method of RACT III Compliance, VOC

Source ID	Source Name	VOC PTE TPY	Exempt from RACT III (yes or no)	How do you intend to comply?	Specify citation of rule or subject to 25 Pa Code RACT regulation, (list the applicable sections)
N/A					

ATTACHMENT B

APPROVED RACT II ANALYSIS

Exelon®

December 13, 2017

Mr. James Beach, P.E.
New Source Review Permit Manager
Air Quality Program
Southeast Region Office
Pennsylvania Department of Environmental Protection
2 E. Main Street
Norristown, PA 19401-4915

Re: **Exelon Generation Company, LLC**
Croydon Generating Station (Title V Operating Permit No. 09-00016)
RACT II and Title V Operating Permit Testing Requirements

Dear Mr. Beach:

Pursuant to our August 24, 2017 meeting and subsequent discussions, Exelon is submitting this revision to the RACT II proposal and Title V Operating Permit (TVOP) Significant Modification application submitted on October 21, 2016 for the Exelon Croydon Generating Station, located in Bristol Township, Bucks County. The Croydon facility contains eight (8) oil-fired simple-cycle combustion turbines ("engines" or "units") that are subject to RACT II requirements pertaining to emissions of oxides of nitrogen (NO_x).

On October 21, 2016, Exelon submitted a TVOP Significant Modification to the Department to incorporate requirements contained in the RACT II regulations (25 Pa. Code §§129.96 through 129.100) into the permit. During its review and in its comments regarding the TVOP Significant Modification, the United States Environmental Protection Agency (USEPA) indicated that the reduced testing requirements included in the TVOP issued on November 18, 2013 (i.e., testing of 3 of 8 engines during each permit term) are inconsistent with the RACT I requirements that are incorporated into the State Implementation Plan (SIP). Although the TVOP specifies testing of 3 of 8 engines, because the SIP has not been revised to reflect the reduced testing frequency, USEPA considers the facility to still be subject to the original testing requirements included with the initial 1996 TVOP (i.e., testing 8 of 8 engines during each permit term).

Therefore, Exelon is submitting revisions to the RACT II proposal and TVOP Significant Modification application submitted on October 21, 2016. These revisions are specifically requesting that the SIP-approved testing frequency requirements (i.e., testing 8 of 8 engines) be replaced with a requirement that specifies testing of 3 of 8 engines during each permit term. Additionally, Exelon is requesting that the Department initiate a SIP revision to change the Croydon testing frequency from 8 of 8 engines to 3 of 8 engines during each permit term[1].

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[1] See TVOP #09-00016, Section C, Condition #007(a) – The permittee shall perform a stack test on three (3) of the eight (8) turbines listed in Section A at least once per permit term, and all eight (8) units at least once every three (3) permit terms. Such testing shall be conducted at least twelve (12) months prior to the expiration of each permit.

Exelon has analyzed engine testing and emission rates for testing conducted since 2008, including the testing of all 8 engines conducted to comply with the SIP testing requirements. A summary of these test data is shown in Table 1. These data indicate that over the approximately 10-year period for which test data are available, NO_x emissions have not exceeded the 0.7 lb/MMBtu limit, and there is relatively little variation among the tested NO_x emissions for the engines. As shown in the table below, the historical mean NO_x emission rate is 0.586 lb/MMBtu, with a relatively small standard deviation of 0.032 lb/MMBtu. Statistically, assuming the data has a normal distribution, the values within two (2) standard deviations of the mean (0.552-0.649 lb/MMBtu) account for 95.45% of the data set, and the values within three (3) standard deviations (0.490-0.682 lb/MMBtu) account for 99.73% of the data set. Hence, the testing already performed to date on these engines demonstrates with an extremely high statistical probability that NO_x emissions from any engine will not exceed the emission limit of 0.7 lb/MMBtu[2]. Therefore, reducing the frequency of testing for these engines would have little, if any, likelihood of resulting in emissions increases from the units.

[2] TVOP #09-00016, Section D, Source IDs 031, 032, 033, 034, 035, 036A, 037, and 038, Condition #004 for each source ID limits the NO_x emissions for each individual turbine to 0.7 lb/MMBtu or 587 pounds per hour, whichever is more stringent.

Table 1. Summary of Emission Test Results

Date	Run No.	Croydon								
		11	12	21	22	31	32	41	42a[1]	42b[1]
		NO_x Emission Rate (lb/MMBtu)								
Jul-08	1	0.510	0.656					0.586		
	2	0.590	0.574					0.582		
	3	0.479	0.565					0.553		
Apr-13	1						0.644			
	2						0.648			
	3						0.653			
May-13	1						0.610			
	2						0.610			
	3						0.610			
Apr-17	1				0.600	0.540			0.600	0.610
	2				0.600	0.550			0.610	0.600
	3				0.610	0.550			0.610	0.600
Apr-17	1				0.590	0.590			0.590	0.600
	2				0.580	0.590			0.590	0.590
	3				0.590	0.590			0.600	0.580
Sep-17	1	0.560	0.560	0.600			0.560	0.600		
	2	0.560	0.560	0.580			0.570	0.600		
	3	0.560	0.560	0.570			0.550	0.600		
Mean		**0.586**								
Standard Deviation (STDEV)		**0.032**								
95.45% of data (Mean ± 2* STDEV)		**0.522 to 0.649**								
99.73% of data (Mean ± 3* STDEV)		**0.490 to 0.682**								

[1] Unit 42 (Source ID 038) is equipped with dual exhaust stacks.

In fact, reducing the required testing frequency for the engines would result in reduced emissions from the site. Units at the site are typically operated only when called on by PJM[3]. The historical annual capacity factor for the units is less than 1 percent, as shown in Table 2 below. This makes it difficult, if not impossible, to efficiently schedule emissions testing in advance. In order to satisfy testing the requirements, it is often necessary to operate a unit or units solely for testing when they would not otherwise be operated,

[3] PJM Interconnection LLC (PJM) is the Regional Transmission Organization (RTO) that coordinates, controls, and monitors the electric grid serving all or parts of Pennsylvania, 12 other states, and the District of Columbia.

resulting in unnecessary emissions. Reducing the frequency of required testing will reduce these periods of unnecessary emissions.

Table 2. Historical Capacity Factor of Each Engine

Year	Engine Capacity Factors							
	11	12	21	22	31	32	41	42
2003	0.05%	0.59%	0.32%	0.83%	0.55%	0.62%	0.42%	0.46%
2004	0.03%	0.03%	0.09%	0.03%	0.03%	0.10%	0.03%	0.10%
2005	0.13%	1.05%	1.34%	1.88%	1.58%	0.50%	1.19%	1.23%
2006	0.22%	0.76%	0.05%	0.90%	0.68%	0.46%	0.75%	0.68%
2007	0.33%	0.18%	0.39%	0.41%	0.16%	0.23%	0.17%	0.22%
2008	0.50%	0.48%	0.31%	0.39%	0.34%	0.34%	0.38%	0.31%
2009	0.21%	0.17%	0.10%	0.10%	0.10%	0.13%	0.25%	0.17%
2010	0.63%	0.59%	0.71%	0.79%	0.81%	0.78%	0.67%	0.67%
2011	0.70%	0.59%	0.55%	0.75%	0.45%	0.46%	0.47%	0.53%
2012	0.27%	0.27%	0.31%	0.22%	0.24%	0.23%	0.08%	0.13%
2013	0.30%	0.32%	0.35%	0.33%	0.25%	0.31%	0.45%	0.31%
2014	1.26%	1.03%	1.11%	1.16%	0.92%	0.82%	0.81%	1.00%
2015	1.16%	1.12%	0.92%	1.18%	1.84%	0.86%	1.51%	1.40%
2016	0.18%	0.41%	0.46%	0.31%	0.26%	0.33%	0.22%	0.22%
Average for all Engines	**0.53%**							

In summary, Exelon is requesting that the October 2016 RACT II submittal and TVOP Significant Modification application be revised to change the emissions testing requirements for the units at Croydon to require that testing be conducted on 3 of the 8 units during the TVOP term. Further, Exelon understands that this change in the testing frequency will require a revision to the Pennsylvania SIP; therefore, Exelon is requesting that the Department initiate action to revise the SIP to replace the requirement for testing 8 of 8 units at Croydon with the requirement to test 3 of the 8 units. As is shown in the summary of emissions test data, this action will not result in an emissions increase and, in fact, will result in lower emissions by reducing operation only for testing purposes.

If you have any questions regarding this request, please do not hesitate to contact me at (610) 765-5316 or albert.hatton@exeloncorp.com.

Sincerely,

Albert M. Hatton III
Manager, Environmental Programs

Exelon Generation.

October 21, 2016

James Rebarchak
Regional Air Program Manager
Pennsylvania Department of Environmental Protection
Southeast Regional Office
2 East Main Street
Norristown, PA 19401

Re: **Exelon Generation Company, LLC**
Croydon Generating Station (Title V Permit No. 09-00016)
Application for a Significant Operating Permit Modification

Dear Mr. Rebarchak:

In order to demonstrate compliance with the Final Rulemaking, Additional Reasonably Available Control Technology (RACT) Requirements for Major Sources of NOx and VOCs codified in 25 Pennsylvania Code §129.96 - §129.100, known as RACT II, Exelon Generation Company, LLC (Exelon) has prepared a case-by-case RACT proposal for the eight (8) combustion turbines located at the Croydon Generating Station. The enclosed significant operating permit modification application is being submitted for approval by the PADEP to incorporate the proposed RACT requirements into the facility's Title V Operating Permit No. 09-00016.

Included in the application are the following sections:

Section 1	General Information Form
Section 2	Compliance Review Form
Section 3	Title V Renewal Application Forms
Section 4	Municipal Notifications

Exelon submits a six month periodic update of the Compliance Review Form. A copy of the most recent Compliance Review Form is included in Section 2.

A check in the amount of $750 for the application fee is enclosed.

If you have any questions or concerns please feel free to contact me directly at (610) 765-5495 or by email John.Tissue@exeloncorp.com.

Thank you,

John Tissue
Senior Program Manager, Air Quality

enclosures

cc: Bryan Bennett
Edwin Much
Jennifer Gutekunst
Dale Davis

REASONABLY AVAILABLE CONTROL TECHNOLOGY PROPOSAL
Croydon Generating Station

Prepared for:

Exelon Generation Company, LLC
Kennett Square, Pennsylvania

Prepared by:

CB&I Environmental & Infrastructure, Inc.
500 Penn Center Boulevard
Suite 1000
Pittsburgh, Pennsylvania 15235

October 2016

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List of Acronyms & Abbreviations

CAA	Federal Clean Air Act
gal	gallons
hr	hour
lbs	pounds
MMBtu	million British thermal units
min	minute
NAAQS	National Ambient Air Quality Standard
NO_x	nitrogen oxides
PADEP	Pennsylvania Department of Environmental Protection
ppmvd	parts per million by volume, dry
RACT	reasonably available control technology
SCR	selective catalytic reduction
USEPA	U.S. Environmental Protection Agency

Executive Summary

On April 23, 2016, the Pennsylvania Environmental Quality Board (EQB) published a final-form rule for additional RACT requirements for major sources of nitrogen oxides (NOx) and/or volatile organic compounds (VOCs), known as RACT II. Affected facilities are required to demonstrate compliance with the RACT II requirements by January 1, 2017. Facilities may demonstrate compliance with RACT II through one of three options including meeting presumptive RACT requirements and/or emission limitations, utilizing facility or system wide NOx averaging or proposing an alternative RACT requirement or emission limitation with a case-by-case RACT evaluation. The alternative RACT proposal must be submitted to the Pennsylvania Department of Environmental Protection (PADEP) by October 24, 2016.

Exelon's Croydon Generating Station (Croydon Station) is a major source of NOx and is therefore required to demonstrate compliance with the RACT II requirements. The Croydon Station, located in Bristol Township, Bucks County, Pennsylvania, consists of eight (8) distillate oil-fired General Electric Frame 7B combustion turbine-generator units nominally rated at 64 MW each and were commissioned in 1974.

The combustion turbines located at the Croydon Station do not meet the presumptive RACT requirements or emission limits promulgated in RACT II. CB&I performed a case-by-case NOx RACT evaluation by first identifying available NOx control technologies for the combustion turbines at the Croydon Station, then performing a technology screening to evaluate the technical feasibility of applying the identified controls to these units. For those controls that were determined to be technologically feasible, a cost evaluation was performed to determine which controls were cost effective.

The RACT evaluation showed that no control technologies are cost effective for the combustion turbines at the Croydon Station. Because no control technologies are cost effective, Exelon is proposing an alternative RACT emission limit and is submitting the following RACT proposal in accordance with 25 Pennsylvania Code §129.92 (RACT proposal requirements). The enclosed significant operating permit modification is being submitted for PADEP's approval to incorporate the presented RACT proposal into the facility's Title V Operating Permit.

1.0 Introduction

1.1 Purpose of Analysis

Under the Federal Clean Air Act (CAA), Reasonably Available Control Technology (RACT) requirements must be re-evaluated when the United States Environmental Protection Agency revises a National Ambient Air Quality Standard (NAAQS). In order to implement the RACT requirements for the 1997 and 2008 8-hour ozone NAAQS, the Pennsylvania Environmental Quality Board (EQB) published a final-form rule on April 23, 2016 for additional RACT requirements for major sources of nitrogen oxides (NOx) and/or volatile organic compounds (VOCs), known as RACT II. Affected facilities are required to demonstrate compliance with the RACT II requirements by January 1, 2017. Facilities may demonstrate compliance with RACT II through one of three options including meeting presumptive RACT requirements and/or emission limitations, utilizing facility or system wide NOx averaging or proposing an alternative RACT requirement or emission limitation with a case-by-case RACT evaluation. The alternative RACT proposal must be submitted to the Pennsylvania Department of Environmental Protection (PADEP) by October 24, 2016.

The Croydon Station is a major source of NOx and is therefore required to demonstrate compliance with the RACT II requirements. This case-by-case NOx evaluation has been developed to meet the alternative RACT proposal petition process allowed under the RACT II requirements.

1.2 Affected Units

The Croydon Station is located at 955 River Road in Bristol Township, Bucks County, Pennsylvania. The station consists of eight (8) distillate oil-fired General Electric Frame 7B combustion turbine-generator units nominally rated at 64 MW each and were commissioned in 1974. The units are operated in accordance with Title V Operating Permit 09-00016 issued by PADEP on November 18, 2013. The following table lists the combustion turbines included in this analysis as listed in the operating permit:

Table 1-1: Emission Unit Summary

Source ID	Source Name	#2 Fuel Oil Throughput
31	Simple Cycle Turbine #11	5,940 Gallons/hr
32	Simple Cycle Turbine #12	5,940 Gallons/hr
33	Simple Cycle Turbine #21	5,940 Gallons/hr
34	Simple Cycle Turbine #22	5,940 Gallons/hr
35	Simple Cycle Turbine #31	5,940 Gallons/hr
36	Simple Cycle Turbine #32	5,940 Gallons/hr
37	Simple Cycle Turbine #41	5,940 Gallons/hr
38	Simple Cycle Turbine #42	5,940 Gallons/hr

The operating permit also includes the following limits:

Table 1-2: Operating Permit Limits

Permit Limits	Value
Facility-Wide NOx (Tons/yr)	1,296
Max. NOx (per turbine) (Lbs/MMBtu)	0.7
Max. NOx (per turbine) (Lbs/hr)	587
Max. fuel throughput (per turbine) (Gallons/hr)	5,940
Capacity Factor (%) (per turbine)	20%
Max. Heat Input (MMBtu/hr) (per turbine)	838

According to RACT II, the applicable presumptive RACT NOx emissions limitations for these combustion turbines under 25 PA Code §129.97(g) is 96 ppmvd NOx at 15% oxygen for combustion turbines firing fuel oil.

1.3 Analysis Methodology

The case-by-case NOx RACT evaluation was completed by first identifying available NOx control technologies for the combustion turbines at the Croydon Station. Next, a technology screening was performed to evaluate the technical feasibility of applying the identified controls to these units. For those controls that were determined to be technologically feasible, a cost evaluation was performed to determine which controls were cost effective. This section includes a general description of the technology screening process and cost evaluation, which are further detailed in Sections 4 and 5 of this report.

1.3.1 Description of Technology Screening Process

The purpose of the technology screening process was to eliminate those combustion turbine installation / emissions control combinations which are technically incompatible. The first step was to establish a set of criteria for use in screening the identified control technologies. Each NOx control option considered was evaluated against the following criteria:

- Process demonstrability
- Commercial availability
- Process/equipment compatibility
    - Combustion turbine equipment compatibility
    - Station configuration / equipment compatibility

The technology screening was based on unit specific information obtained from the manufacturer, General Electric, and site engineers at Exelon. Control options that did not meet this criteria were eliminated and were not considered in the cost evaluation phase. Details of the technology screening are included in Section 4.

1.3.2 Description of the Cost Evaluation Process

This second phase of the study considers capital costs, operating and maintenance costs and the effects of the identified control options on unit performance and plant systems. The cost evaluation was developed in accordance with the methodology outlined in USEPA's OAQPS Control Cost Manual.

Capital costs for major equipment were estimated based on information from equipment suppliers. Costs such as those for foundations and supports, handling and erection, piping and indirect costs such as engineering, construction and field expenses were estimated as percentage of purchased equipment cost as per OAQPS methodology and site-specific conditions.

Operating and maintenance costs were developed for each of the technologies. These operating and maintenance costs are a constituent of the total compliance cost over the life of the plant and are needed to project the levelized life cycle compliance cost. In addition, performance impacts on existing plant systems were considered.

The economic analysis was used to determine the annualized cost of the technologies. The annualized cost included: (i) recovery of capital costs using a discount rate; (ii) annual direct cost of utilities, reagents, and operation & maintenance (O&M) costs; and (iii) indirect costs such as overhead, administrative charges, contingency, taxes & insurance. The NOx removed was based on the difference of the annual emissions at baseline and after implementation of the control technology. The annualized cost for each control option was then divided by the amount of NOx removed, in tons/year, to establish the cost-effectiveness in constant dollars/ton NOx. Details of the methodology are included in Appendix A.

2.0 Description of Baseline Conditions

The baseline NOx emissions used in the RACT analysis represents current operating conditions at the Croydon Station. The RACT analysis is based on the maximum expected emissions situation and considers the combustion turbine-generator load, heat input, and emissions levels based on recent emission testing results. The baseline NOx emissions are summarized in the following table and correspond with the facility's current NOx permit limits.

Table 2-1: Baseline Emissions

					Baseline NOx Emissions			
Source Description	**Number of Units**	**Load (MW)**	**Heat Input (MMBtu/hr)**	**Fuel Type**	**lb/MMBtu**	**ppmvd@15% O2**	**lb/hr**	**Tons/yr (all units)**
GE Frame 7B Simple Cycle Combustion Turbines	8	64	838	#2 Fuel Oil	0.7	180	587	1296

3.0 NOx Control Technologies

The principal nitrogen pollutants generated by combustion turbines are nitric oxide (NO) and nitrogen dioxide (NO_2), collectively known as NOx. NOx is primarily formed by two mechanisms in the combustion turbine combustor. The first and primary mechanism is the fixation of atmospheric nitrogen during the combustion process and the resultant pollutant is referred to as thermal NOx. The second mechanism is the conversion of the fuel bound nitrogen to NOx in the presence of excess air during the combustion process. EPA has determined that there is little fuel bound NOx formation in natural gas and distillate oil fired combustion turbines and thermal NOx is the dominant mechanism in this source category.

Several NOx thermal control technologies are commercially available for combustion turbines. These technologies include:

- Water injection
- Fuel switching
- Selective Catalytic Reduction (SCR)
- Dry low-NOx combustors

This section provides a brief description of these technologies.

3.1 Water Injection

This technology is based on the injection of demineralized water into the combustion zone. This has the effect of lowering the peak flame temperature, thus reducing the level of production of thermal NOx. After admission to the combustor, the water both dilutes the combustion product stream and vaporizes while absorbing the heat of vaporization. This action lowers the peak combustion temperature. The additional mass flow rate through the combustion turbine due to water injection increases the output of the unit and decreases its efficiency. Water injection may also affect the internals of the turbine requiring more frequent maintenance. Water injection is commonly used for NOx reduction and power augmentation on combustion turbines and it is considered a proven technology. This control technology is considered technically feasible for the RACT affected units.

Water injection can typically reduce NOx emissions from combustion turbines by about 60-75% from the uncontrolled condition. The maximum reduction level depends on the combustion turbine design. Typically, the major unit/plant modifications required to install water injection system include the following items:

- A demineralized water supply and storage system
- Water injection skid, manifold and nozzles
- Modifications/additions to the combustion turbine control systems

- Modifications to the combustion turbine fuel systems
- Burner replacement

Water injection is considered a technically feasible control technology for these units.

3.2 Fuel Switching

This method reduces the production of NOx by switching to a fuel which produces less NOx. In the case of switching from oil to natural gas fuel, there is a significant impact on the production of thermal NOx since the flame temperature of natural gas is about 100 degrees lower than that of distillate fuel.

In cases where a natural gas supply line is in close proximity to a plant, switching from distillate oil to natural gas is a feasible method of NOx control. In most cases, however, where natural gas in not immediately available, the cost of bringing the fuel to the plant makes the fuel-switch option cost prohibitive.

There are no natural gas pipelines near the Croydon Station. Switching to natural gas will require laying of a large natural gas pipeline infrastructure and access at the site. This option will require detailed environmental assessment of the impacts of the pipeline on the surrounding media, industrial and residential area surrounding the facility. This option will be also extremely expensive. This technology is therefore considered not technically feasible for the RACT affected units.

3.3 Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction (SCR) removes NOx from the gas at the exhaust of the combustion turbine. The SCR system comprises various components, with the central component being the reactor containing the catalyst. This catalyst is typically an active phase of vanadium pentoxide on a carrier of titanium dioxide, formed into elements of a parallel flow configuration. A honeycomb-shaped substrate is the common shape of catalyst elements. The normal operating temperature for the catalytic process is typically 550°F to 900°F. The minimum operating temperature is plant-specific and depends on flue gas conditions.

Turbine exhaust that exceeds the maximum catalyst operating temperature must be cooled to within the catalyst reaction temperatures range and to prevent catalyst damage due to excessive heat. Tempering air fans that draw ambient air into the exhaust steam prior to the catalyst are used to control maximum temperatures but increase the system complexity, cost and the amount of exhaust that requires treatment.

The SCR process uses ammonia as the reducing agent to convert the NOx to nitrogen (N_2) and water vapor at the catalyst surface. Ammonia vapor is introduced into the flue gas duct via an ammonia injection grid (AIG) ahead of the SCR reactor and catalyst. The ammonia in the presence of catalyst causes the NOx to break down into nitrogen and water, which both are harmless compounds. One mole of ammonia reacts with one mole of NOx. A minor portion of ammonia will leave the catalyst unreacted. This unreacted ammonia is referred to as ammonia slip. With the reduction of NOx, other reactions between NOx and ammonia can also take place, but to a minor extent.

On the catalyst surface, the primary chemical reactions that occur are:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

$$NO + NO_2 + 2\ NH_3 \rightarrow 2\ N_2 + 3\ H_2O$$

The lower SCR operating temperature is determined from the composition of the flue gas with respect to SO_3, water, and NH_3. These compounds will form ammonia sulfate and ammonia bisulfate as the temperature is decreased. These salts will deposit in the catalyst pores and cause it to deactivate. The operating temperature is chosen to minimize this condensation.

Several side reactions may occur under certain conditions, but the oxidation of SO_2 to SO_3 is of most concern. This reaction is usually minimized by optimal catalyst design. The oxidation rate increases as the flue gas temperature increases, another flue gas temperature driver.

SCR is considered a technically feasible control technology for these units.

3.4 Dry Low NOx Combustors

Dry low NOx combustors utilize a staged combustion process to minimize residence time in the high temperature portion of the flame. They are also designed for very lean fuel-air mixtures, such that there is more oxygen available than there is fuel which results in a lower flame temperature.

General Electric has not yet developed a dry low NOx burner retrofit for firing distillate oil for this model combustion turbine firing distillate oil. When firing distillate oil, the use of a dry low NOx burner requires the concurrent use of water injection. This control technology is therefore not technically feasible for these RACT affected units.

4.0 Technology Screening Analysis

The following technologies were considered during the initial screening analysis:

- Water injection
- Fuel switching
- Selective Catalytic Reduction (SCR)
- Dry low-NOx combustors

The control options were evaluated based on process demonstrability, commercial availability, technical compatibility with the combustion turbine equipment and compatibility with the existing plant systems. In addition, the manufacturer of the combustion turbines, General Electric, assessed the available NOx control strategies based on the turbine configuration, model number, serial number and fuel type. Based on the analysis of the available NOx control technologies, water injection and SCR are the only options that passed the technology screening for the Croydon Station. A letter from General Electric confirming the available NOx controls for these units is included in Appendix B.

Fuel switching failed due the lack of a gas supply line in the vicinity of the station. Dry low NOx combustors were dropped from the analysis because General Electric has not developed a dry low NOx burner retrofit for firing distillate fuel for this model turbine.

Based on the results of the technology screening, water injection and SCR were included in the cost evaluation discussed in Section 5.

5.0 Economic Analysis

Based on the results of the technology screening analysis, water injection and SCR are the only technologically feasible NOx control options for the combustion turbines at the Croydon Station. These control technologies were further analyzed for cost effectiveness. This section provides a detailed description of the methodology used to complete the cost analysis.

The cost estimates were based on the control technology option (i.e. water injection or SCR) being installed on each combustion turbine and controlling the NOx from baseline level of 180 ppmv @15% O_2 (0.7 lbs/MMBTu) to presumptive RACT II level of 96 ppmv @ 15% O_2. Exelon is not proposing to use emission averaging between the units.

5.1 Total Capital Investment

Total installed capital cost of the technology was estimated, including mechanical equipment, piping, structures, foundations, electrical work, installation and indirect costs including engineering and construction supervision. Vendor quotations were used for equipment costs of the water injection and SCR systems. The methodology presented in the QAQPS Control Cost Manual was used to develop direct and indirect installation costs. The calculation of capital costs for water injection and SCR are presented in Appendix A, Tables A-3 and A-6, respectively.

5.2 Annualized Cost Analysis

Annual operating costs including operating and maintenance labor, reagent (ammonia) cost, catalyst replacement and demineralized water costs were estimated based on information from current plant operations and engineering estimates based on methods in the QAQPS Control Cost Manual. Auxiliary power and heat rate penalties resulting from the addition of the control technologies were also taken into account. In addition, a penalty for changes in unit capacity was calculated and expressed in terms of equivalent annual cost.

Annualized capital costs were determined by multiplying the total installed capital investment by the capital recovery factor, which was calculated based on an expected plant life of 20 years and an estimated interest rate of 10%.

The economic factors used in developing the annual costs for water injection and SCR are presented in Appendix A, Tables A-4 and A-7, respectively.

5.3 Control Technology Cost Effectiveness

After the total annual cost incurred for the installation of the control technology was determined, the cost effectiveness of the technology was determined by calculating a value for cost in dollars per ton NOx removed. This value was calculated by dividing the total annualized cost by the amount of NOx removed in tons per year. The cost effectiveness in dollars per ton NOx removed was determined to be $6,103/ton for water injection and $8,531/ton for SCR. A summary of the cost effectiveness results are included in the following table, and detailed calculations are included in Appendix A.

Table 5-1: Summary of Cost Analysis

Item	Water Injection	SCR
Total Direct Costs (TDC)	$ 20,939,406	$ 39,844,560
Total Indirect Installation Costs (TIIC)	$ 7,555,166	$ 17,131,777
TOTAL INSTALLED COST (TIC)	$ 28,494,572	$ 56,976,337
Total Utilities Cost	$ 931,820	$ 3,665,483
Additional Operation and Maintenance (O&M) Cost	$ 262,667	$ 178,434
Fuel Penalty	$ 2,663,977	$ 1,450,894
TOTAL DIRECT (O&M) COSTS	$ 3,858,464	$ 5,294,811
Additional Total Direct and Indirect Annual Costs (TIIC)	$ 8,360,296	$ 9,673,152
Capital Recovery Cost	$ 3,346,962	$ 6,692,419
TOTAL ANNUAL COSTS	$ 11,707,258	$ 16,365,571
NOx Emissions - Reduction (TPY):	$ 1,918	$ 1,918
Cost Effectiveness ($/Ton):	$ 6,103	$ 8,531

(1) Based on difference in annual emissions from baseline condition of 180 ppmv @ 15% O_2 to presumptive RACT II limit of 96 ppmv @15% O_2

The presumptive RACT benchmark for cost effectiveness is $2,800/ton NOx. The RACT II preamble notes that a 25% buffer to the cost-effectiveness will not change the presumptive RACT determination. This buffer increases the presumptive RACT benchmark to $3,500/ton NOx. Based on this benchmark, the cost analysis shows that both water injection and SCR are not cost effective for the combustion turbines at the Croydon Station.

6.0 RACT Proposal

Based on the technology screening analysis and economic analysis completed, there are no add-on NOx control technologies that are technologically feasible or cost effective for the combustion turbines at the Croydon Station. The baseline NOx emissions show that the units do not meet the presumptive RACT requirements or emissions limits specified in RACT II. Because the units do not meet the presumptive RACT emission limits, Exelon has prepared this case-by-case RACT proposal in accordance with the requirements of 25 Pennsylvania Code §129.92 for approval by the PADEP. A significant operating permit modification application has been prepared to incorporate the proposed RACT requirements into the facility's existing Title V Operating Permit. The modification application form along with the required General Information Form, Compliance Review Form and municipal notifications are included in Appendix C of this document. The proposed RACT requirements are as follows.

6.1 Emission Restrictions

The facility will operate in accordance with a Title V Operating Permit that restricts NOx emissions to the following permit limits:

Permit Limits	Value
Facility-Wide NOx (Tons/yr)	1,296
Max. NOx (per turbine) (Lbs/MMBtu)	0.7
Max. NOx (per turbine) (Lbs/hr)	587
Capacity Factor	20%

The baseline emission rate used in the economic analysis is based on the existing permit limit 0.70 lbs/MMBtu, which converts to a value of 180 ppmvd@15% O_2 using stack conditions. Because the RACT evaluation showed that there were no cost effective control technologies for the combustion turbines at the Croydon Station, Exelon proposes to keep the 0.70 lbs/MMBtu on a 30-day rolling average basis as the case by case RACT limit for each turbine.. Exelon will also maintain the facility-wide NOx limit of 1,296 tons per year and the hourly NOx limit of 587 lbs/hr per turbine.

6.2 Testing Requirements

Exelon will demonstrate compliance with the proposed NOx RACT emission limitation with source testing in accordance with the terms and conditions of the facility's existing Title V Operating Permit. Exelon will test for the NOx emissions in lbs/MMBtu and lbs/hr in accordance with the provisions of 25 Pennsylvania Code §129 and 145. Exelon shall perform the testing on three of the eight turbines at least once per permit term and all eight of the turbines at least once every three permit terms.

6.3 Monitoring, Recordkeeping and Reporting Requirements

Exelon will continue to comply with the monitoring, recordkeeping and reporting requirements in accordance with the facility's existing Title V Operating Permit. Exelon will record monthly fuel consumption, monthly electrical power generated, monthly and twelve month rolling capacity factor for each turbine and monthly NOx emissions calculated using the most recent stack test results. The facility will also maintain records of the emissions tests conducted on the turbines. NOx emissions will be reported annually in the facility's annual emissions report submitted to the PADEP.

Appendix A

Economic Analysis Calculations

Exelon Generation
Croydon Station
RACT II Control Technology Cost Evaluation
Table A-1: Summary of Results

Summary of Results

Item	Water Injection	SCR
Site Average Capacity Factor	20%	20%
Total Direct Costs (TDC)	$20,939,406	$39,844,560
Total Indirect Installation Costs (TIIC)	$7,555,166	$17,131,777
TOTAL INSTALLED COST (TIC)	$28,494,572	$56,976,337
Total Utilities Cost	$931,820	$3,665,483
Additional Operation and Maintenance (O&M) Cost	$262,667	$178,434
Fuel Penalty	$2,663,977	$1,450,894
TOTAL DIRECT (O&M) COSTS	$3,858,464	$5,294,811
Additional Total Direct and Indirect Annual Costs (TIIC)	$8,360,296	$9,673,152
Capital Recovery Cost	$3,346,962	$6,692,419
TOTAL ANNUAL COSTS	$11,707,258	$16,365,571
NOx Emissions - Reduction (TPY):	1918.42	1918.42
Cost Effectiveness ($/Ton):	**$6,103**	**$8,531**

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RACT II Control Technology Cost Evaluation

Table A-2: Basis for Calculations

Parameter	Value	Units	Reference/Basis
Unit Description:			
Unit Type	GE Frame 7B Simple Cycle		
Number of units	8		
CT Load	64	MW	10 Deg F - Winter Condition (Note: 49 MW in summer)
Fuel	Fuel oil #2		
Maximum Heat Input at 10 F ambient	838	mmbtu/hr	Croydon TV permit
NOX Permit Limit	0.7	lb/mmbtu	Croydon TV permit
NOX Permit Limit	586.6	lb/hr	Croydon TV permit
NOX Permit Limit at 100% CF per CT	2569	tpy/CT	calculated
NOX Permit Limit at 100% CF for all 8 CTs	20554	tpy/all 8 CTs	calculated
Permitted capacity factor for each CT	20%		TV permit
NOX Permit Limit at site average CF for all 8 CTs	4111	tpy/all 8 CTs	calculated
Design Control Condition:			
Baseline Uncontrolled Emissions	180	ppmvd @15% O2	Estimated based on lbs/MMBTU limit in TV permit
	0.700	lbs/MMBTu	Title V permit
Presumptive RACT	96	ppmvd @15% O2	PADEP 129.98 Limit
	0.373	lbs/MMBTu	calculated
NOx Control per CT	0.327	lbs/MMBTu/CT	calculated
% control	46.7%		calculated
Annual NOx Controlled at 100% capacity factor	1199.01	tpy/CT	calculated
Permitted Capacity Factor	20%	each	
Average capacity factor for site	20%		
Annual NOx Controlled at permitted capacity factor	239.80	tpy/CT	calculated
No. of units at Facility	8		
Total NOx Controlled at Permitted Capacity Factors	1918.42	tpy for all 8 CTs	calculated
Labor Requirements			
Hourly Cost of Operation Labor	$73.80	per hour	Based on annual burdened rate of $147607 and 2000 hrs/yr
Hourly Cost of Maintenance Labor	$73.80	per hour	Based on annual burdened rate of $147607 and 2000 hrs/yr
Hourly cost of supervisory labor	$82.79	per hour	Based on annual burdened rate of $165,585 and 2000 hrs/yr
Estimated annual operating labor at site - Water Injection	2000	hrs/yr	Estimated 2000 hrs per year of operation - one (1) operator present during operation
Estimated annual maintenance labor at site - Water Injection	52	hrs/yr	Routine and emergency maintenance; Station is currently unmanned
Estimated annual operating labor at site - SCR	2000	hrs/yr	Estimated 2000 hrs per year of operation - one (1) operator present during operation
Estimated annual maintenance labor at site - SCR	52	hrs/yr	Routine and emergency maintenance; Station is currently unmanned
Estimated supervisory labor as percentage of op/main labor	10%		Estimated
Economic Factors			
Life of Units	20	years	
Construction Period - water Injection	1	year	Site-specific estimate based on staging of construction
Construction Period - SCR	2	year	Site-specific estimate based on staging of construction
State tax (PA)	6%	Pennsylvania state tax	
Local tax	0%	Outside Philadelphia	
Interest during construction	4.7%	Exelon Data	
Interest on Capital	10.0%	Exelon Data	
Reagent/Fuel			
Delivered Demin Water Cost	$13.00	$/1000 gal	Based on Exelon data for similar sites
Delivered 19% Aqueous Ammonia Cost	$0.451	$/Lb of aqueous ammonia	Exelon data
Fuel oil heating value	137560	BTU/Gallon	TV Permit
Delivered #2 Fuel Oil Cost	$1.56	$/gallon	Exelon data
Electricity cost for site	$183.08	$/MWH	Site Data See tab "PJM Oil RACT Revenue - Confidential" under reference tabs
SCR Catalyst cost as % of total system cost	15.00%	of quoted system cost	Vendor (GE) data
SCR Catalyst Life for site average capacity factor	3	years	Vendor (GE) data
Performance Impacts			
Estimated net heat rate increase for water injection	2.00%	Estimated from vendor (GE) communication	
Estimated net derating of output for SCR pressure drop	0.42%	per 4 inch wg pressure drop	Vendor (GE) communication
Estimated SCR pressure drop	12	inch wg	Vendor (GE) communication
PJM Operating Requirements			
Continuous operation required from PJM	72	Hours at any time	PJM requirement
Average downtime between continuous operations	8	Hours at any time	estimated
Water and ammonia tank rated for	144	hours of continuous operation	calculated

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Table A-3: Capital Costs for Water Injection

Item				Basis	Unit Cost	Subtotal	Total
DIRECT COSTS							
• **Purchased Equipment**							
Purchased Equipment (PE)						$12,576,220	
	(8) Water injection system GE supply			GE proposal	$7,074,200		
	Laser scan survey (total for all units)			GE proposal	$113,200		
	(8) GE Mark Vie controls upgrade			GE proposal	$3,200,000		
	(8) NOx analyzers @$50k each			Engr Estimate	$400,000		
	(3) On-site Monitoring Lite Instrumentation			GE proposal	$38,820		
	(2) 1 million gallon demineralized water storage tanks & pumps			Engr Estimate	$1,750,000		
Freight & Tax Subtotal						$1,383,384	
	Freight	5.0%	assumed	% of PE	$628,811		
	Sales Tax	6.0%	Site	% of PE	$754,573		
	Local tax	0.0%					
Purchased Equipment Cost (PEC)						**$13,959,604**	
• **Direct Installation Cost**							
Foundations & Supports		8.0%	OAQPS	% of PEC		$1,116,768	
Handling and Erection		20.0%		% of PEC	Eng Estimate for site	$2,791,921	
Site Prep including relocation of interferences		10.0%	OAQPS	% of PEC		$1,395,960	
Buildings		0.0%		% of PEC	None needed	$0	
Electrical (MCC, wiring, control dashboards)		4.0%	OAQPS	% of PEC		$558,384	
Piping (All including recirculation except from vendor)		2.0%	OAQPS	% of PEC		$279,192	
Insulation, heat tracing		4.0%		% of PEC		$558,384	
Painting		2.0%		% of PEC		$279,192	
Direct Installation Cost (DIC)						**$6,979,802**	
Total Direct Costs (TDC)							**$20,939,406**
INDIRECT INSTALLATION COSTS							
• **Engineering and Project Management**		10.0%	OAQPS	% of PEC		$1,395,960	
• **Construction and Field Expenses**		5.0%	OAQPS	% of PEC		$697,980	
• **Contractor Fees**		10.0%	OAQPS	% of PEC		$1,395,960	
• **Start-up**		2.0%	OAQPS	% of PEC		$279,192	
• **Performance Test including initial RATA**				Estimate		$10,000	
• **Contingencies**		20.0%	OAQPS	% of PEC		$2,791,921	
• **Interest During Construction**				TDC*I*n		$984,152	
Construction Period (n)		1	Years				
Interest Rate (I)		4.7%		Exelon data			
Total Indirect Installation Costs (TIIC)							**$7,555,166**
TOTAL INSTALLED COST (TIC)							**$28,494,572**

Basis:
1: Retrofit of eight (8) GE 7B combustion turbines. to reduce NOx to 96 ppmvd @15% O2 (RACT Presumptive Limit).
2: Cost of water injection system including injection skid, piping from skid to combustors, new shower head liquid fuel nozzles, revised control curve, and laser scan survey for developing system layout from General Electric October 7, 2016 budgetary proposal.
3: Cost of controls upgrade to GE Mark VIe required for GE to incorporate water injection control program and associated combustor tuning per GE October 7, 2016 budgetary price; GE price includes hardware and installation.
4: Cost of demineralized water receiving and storage system (tank sized for maximum 144 hours of full load operation of all eight units) from engineering estimates.
5: All other costs are based on either percentages for generic plants per OAQPS manual or engineering judgement based on site specific data.

Notes

Cost for GE Mark Vie controls upgrade per combustion turbine =	$400,000	
Cost for GE water injection scope of supply per combustion turbine including the revised control curve=	$884,275	
Cost for site laser scan survey =	$113,200	
Cost to Install GE remote monitoring to maintain required reliability	$38,820	
Full load water injection rate per combustion turbine (GE Data)=	27400	lb/h
Full load water usage with all Combustion turbines operating at full load =	219200	lb/h
	438	gpm
Minimum demineralized water storage requirement =	1,892,374	gallons

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Croydon Station
RACT II Control Technology Cost Evaluation
Table A-4: Operating and Annualized Costs for Water Injection

Item	Variables		Basis	Unit Cost	Subtotal	Total
Total Direct Costs (TDC)	*(Calculated on previous table)*					**$20,939,406**
TOTAL INSTALLED COST (TIC)	*(Calculated on previous table)*					**$28,494,572**
ANNUAL COSTS						
• **Utilities Cost**					$333,199	
Utility Rate	183.077	$/MW-hr	estimated			
Capacity	1,820	MW-hr/yr				
• **Demin water Cost**					$598,621	
Total Utilities Cost						**$931,820**
• **Additional Operation and Maintenance (O&M) Cost**						
Annual Maintenance Labor Cost					$3,838	
Annual operating Labor Cost					$147,607	
Annual supervisory Labor cost					$16,989	
Annual testing cost including RATA				estimate	$10,000	
Annual Maintenance Material Cost					$59,900	
Annual Inspection Cost					$24,333	**$262,667**
• **Fuel Penalty**						
Additional fuel cost for compensating higher heat rate					$2,663,977	**$2,663,977**
• **Capacity Change Credit**					$0	**$0**
Total Direct (O&M) Cost						**$3,858,464**
ADDITIONAL INDIRECT ANNUAL COSTS						
• **Overhead**	60%		% of O&M - OAQPS			**$2,315,079**
• **Administrative Charges**	2%		% of TCI - OAQPS			**$569,891**
• **Annual Contingency**	5%		% of TDC - OAQPS			**$1,046,970**
• **Property Taxes**	1%		% of TCI - OAQPS			**$284,946**
• **Insurance**	1%		% of TCI - OAQPS			**$284,946**
Total Additional Indirect Costs						**$4,501,832**
Additional Total Direct and Indirect Annual Costs (TIIC)						**$8,360,296**
• **Capital Recovery Cost**			TCI*CRF - OAQPS			**$3,346,962**
Life (n)	20		assumed			
Interest Rate (i)	0.10		Exelon Input			
Capital Recovery Factor (CRF)	0.1175		$(i*(1+i)^n)/((1+i)^n-1)$			
TOTAL ANNUAL COSTS						**$11,707,258**

COST EFFECTIVENESS ANALYSIS (Total Annual Costs / Emissions Reduction) based on Average Permitted Capacity Factor of 23.8%	
Total Annual Costs:	**$11,707,258**
NOx Emissions - Reduction (TPY):	1918.42
Cost Effectiveness ($/Ton):	**$6,103**

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RACT II Control Technology Cost Evaluation
Table A-5: Water Injection Supporting Calculations

Electricity Cost Calculation:

No. of combustion turbines	8	#	Comments
Demineralized Water Tank Pumps, power	170	hp	Required water pressure at water injection skid: 15-65 psig per GE; full load water injection rate is 438 gpm; pressure at combustor showerhead estimated at 200 psig
Annual hours of operation	8760	hr/yr	
Average capacity factor for site	20.0%		TV permit
Expected annual hour of operations for pumps	1752	hr/yr	
Annual power consumption for pumps	1,777	MW-hr/yr	Calculated
Demin water storage tank heaters	2	#	
Tank heater power	30	kw	Tank heater average winter electric usage
Annual hours of operation winter only	720	hr/yr	4 months in a year (winter) - 6 hours a day (during night when ambient is <32 F)
Annual power consumption heater	43	MW-hr/yr	Calculation
Total Additional Parasitic Power Requirements	1,820	MW-hr/yr	
Cost of electricity Generation at site:	$183.08	per MW-hr	Site data
Annual electricity cost:	$333,199	per year	Calculation

Demineralized Water Cost Calculations:

Water usage rate per CT	27400	lb/hr	Vendor (GE) Data
No. of CTs operating	8	# of units	
Total water usage at site	219200	lbs/hr	
Total hours per year	8760	hrs/yr	
Site average capacity factor	20.0%		TV permit
Annual water usage rate	384038400	lbs/yr	
	46048	1000 gals/yr based on water density of 8.34 lbs/gal	
Delivered cost of Demin water	13	$/1000 gal	Based on Exelon data for similar sites
Annual cost of water	$598,621	per year	Calculation

Labor Costs

Operating Labor

Annual operating labor requirements per shift for site	2000	hrs/yr	Estimated 2000 hrs per year of operation - one (1) operator present during operation
Site specific labor costs for operating labor	$73.80	$/hr	site data
Annual operating labor cost	$147,607	$/yr	

Maintenance labor

Annual maintenance labor requirements per shift for site	52	hrs/yr	Routine and emergency maintenance; Station is currently unmanned
Site specific labor costs for operating labor	$73.80	$/hr	Site data
Annual operating labor cost	$3,838	$/yr	

Supervisory Labor:

Supervisory Labor hours	205	hr/yr	10% of operating & maintenance labor
Supervisory labor rate	$82.79	$/hr	
Supervisory Labor cost	$16,989	$/yr	

Total labor cost	$168,434	$/yr	

Maintenance Material & Inspection Cost

Maintenance material cost for site per year	$59,900	per yr	Same as 2012 RACT Study
Inspection Cost (combustion system) for Site per 3 years	$73,000	per 3 years	Same as 2012 RACT Study
Annual inspection cost	$24,333	per year	calculated

Fuel Penalty Cost:

Net estimated heat rate increase at NOx limit of 96 ppmvd @15% O2	2.00%	Based on vendor (GE) communication	
Rating of each simp0le cycle unit	838	MMBTU/hr	
Capacity factor for simple cycle units	20%		
Average permitted capacity factor for station	20%		
Total annual heat input for station at site average capacity factor	11745408	MMBTU/yr	basis: 8 units
Additional heat input due to heat rate increase due to water injection	234908	MMBTU/yr	incremental value due to increase in heat rate
Fuel oil high heating value	137560	Btu/gal	Station TV Permit Data
Additional fuel oil requirement	1707678	gal/yr	
Delivered cost of fuel oil at site	$1.56	$/gal	Site data: Ref John Tissue email dated October 10, 2016
Additional fuel cost at site for all 8 CTs	$2,663,977	$/yr	for all 8 CTS

Capacity Change Credit

Capacity change credit is the revenue gained by the facility due to increased output of the facility for operating water injection. The facility plans to maintain the permitted capacity (64 MW) because the safety and operability impacts of higher generation capacity on downstream electrical equipment are unknown at this time. The facility will increase the fuel input to compensate lower heat rate as shown above under Fuel Penalty Cost. Therefore, capacity change credit is not calculated.

Exelon Generation

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RACT II Control Technology Cost Evaluation

Table A-6: Capital Costs for Selective Catalytic Reduction (SCR)

Item			Basis	Unit Cost	Subtotal	Total
DIRECT COSTS						
• **Purchased Equipment**						
Purchased Equipment (PE)					$25,640,000	
(8) SCR & Auxiliaries Cost			GE proposal	$24,440,000		
NOx analyzers before & after each SCR			Engr Estimate	$800,000		
40,000 gallon 19% aqueous ammonia storage system including pumps			Existing Estimate	$400,000		
Freight & Tax Subtotal					$2,820,400	
Freight	5.0%	assumed	% of PE	$1,282,000		
Sales Tax	6.0%	Site	% of PE	$1,538,400		
Purchased Equipment Cost (PEC)					**$28,460,400**	
• **Direct Installation Cost**						
Foundations & Supports	8.0%	OAQPS	% of PEC		$2,276,832	
Handling and Erection	15.0%	OAQPS	% of PEC		$4,269,060	
Site Prep including removal of ductwork & relocation of interferences.	10.0%	OAQPS	% of PEC		$2,846,040	
Buildings	0.0%		% of PEC	None needed	$0	
Electrical(MCC, wiring, control dashboards)	4.0%	OAQPS	% of PEC		$1,138,416	
Piping (All except those from Vendor)	2.0%	OAQPS	% of PEC		$569,208	
heat tracing, Insulation, laggings for ductwork	0.0%		% of PEC	included by vendor	$0	trench
Painting	1.0%		% of PEC		$284,604	
Direct Installation Cost (DIC)					**$11,384,160**	
Total Direct Costs (TDC)						**$39,844,560**
INDIRECT INSTALLATION COSTS						
• **Engineering and Project Management**	10.0%	OAQPS	% of PEC		$2,846,040	
• **Construction and Field Expenses**	5.0%	OAQPS	% of PEC		$1,423,020	
• **Contractor Fees**	10.0%	OAQPS	% of PEC		$2,846,040	
• **Start-up**	2.0%	OAQPS	% of PEC		$569,208	
• **Performance Test including initial RATA**			Estimate		$10,000	
• **Contingencies**	20.0%	OAQPS	% of PEC		$5,692,080	
• **Interest During Construction**			TDC*I*n		$3,745,389	
Construction Period (n)	2	Years				
Interest Rate (I)	4.7%					
Total Indirect Installation Costs (TIIC)						**$17,131,777**
TOTAL INSTALLED COST (TIC)						**$56,976,337**

Basis:
1: Retrofit of eight (8) GE 7B combustion turbines.
2: Cost of SCR system including tempering air fan ,ammonia injection grid, catalyst, ammonia injection skid, and controls from General Electric September 30, 2016 indicative proposal.
3: Cost of ammonia receiving and storage system CEMS from CB&I engineering estimate.
4: Existing exhaust system on each unit must be removed to GT exhaust flange; stack to be re-used.
5: All other costs are based on either percentages for generic plants per OAQPS manual or engineering judgement based on site specific data.

Notes

SCR equipment cost from GE = $24,440,000
(includes one dilution air fan only)

SCR Equipment freight cost from GE = $1,952,000
other freight costs to be added

Exelon Generation

Croydon Station

RACT II Control Technology Cost Evaluation

Table A-7: Operating and Annualized Costs for SCR

Item	Variables	Basis	Unit Cost	Subtotal	Total
Total Direct Costs (TDC)	*(Calculated on previous table)*				**$39,844,560**
TOTAL INSTALLED COST (TIC)	*(Calculated on previous table)*				**$56,976,337**
ANNUAL COSTS					
• **Utilities cost for additional parasitic load**				$833,952	
Utility Rate	183.077 $/MW-hr	Site Data			
Parasitic load	4,555 MW-hr/yr	Calculated			
• **Cost of derating of unit due to SCR pressure drop**					
Utility Rate	183.077 $/MW-hr	Site data		$2,069,227	
Derated load	11,303 MW-hr/yr	Calculated			
• **Reagent (19% aqueous ammonia) Cost**				$762,304	
Total Utilities Cost					**$3,665,483**
• **Additional Operation and Maintenance (O&M) Cost**					
Annual Maintenance Labor Cost			$3,838	$3,838	
Annual Operating Labor Cost			$147,607	$147,607	
Annual supervisory Labor Cost			$16,989	$16,989	
Annual testing cost including RATA			$10,000	$10,000	Estimate
Total O&M Cost					**$178,434**
• **Additional Catalyst Replacement and Disposal Cost**					
System Cost	$24,440,000	Vendor (GE) proposal			
- Basis of Catalyst Cost	15.0%	% of System Cost	Vendor (GE) data		
Catalyst Cost				$3,666,000	
Spent Catalyst Disposal & New Catalyst Installation Cost	25%	% of Catalyst Cost - Eng estimate		$916,500	
Sales Tax - State	6%	% of Catalyst Cost		$219,960	
Sales Tax - Local	0%			$0	
Total Costs				$4,802,460	
• **Annualized Catalyst Replacement and Disposal Cost**					
- Catalyst Life (n)	3	estimated			
- Interest Rate (i)	0.10	Exelon data			
Future Worth Factor (FWF)	0.302	$i*(1)/((1+i)^n-1)$			
Total Catalyst Cost		(Total Costs) * (FWF)			**$1,450,894**
• **Total Direct Annual Cost**					**$5,294,811**
INDIRECT ANNUAL COSTS					
• **Overhead**	60%	% of O&M - OAQPS			**$107,060**
• **Administrative Charges**	2%	% of TCI - OAQPS			**$1,139,527**
• **Annual Contingency**	5%	% of TDC - OAQPS			**$1,992,228**
• **Property Taxes**	1%	% of TCI - OAQPS			**$569,763**
• **Insurance**	1%	% of TCI - OAQPS			**$569,763**
Total Additional Indirect Costs					**$4,378,342**
Total Direct and Indirect Annual Costs (TIIC)					**$9,673,152**
• **Capital Recovery Cost**		TCI*CRF - OAQPS			**$6,692,419**
Life (n)	20	assumed			
Interest Rate (i)	0.10	Exelon data			
Capital Recovery Factor (CRF)	0.1175	$(i*(1+i)^n)/((1+i)^n-1)$			
TOTAL ANNUAL COSTS					**$16,365,571**

COST EFFECTIVENESS ANALYSIS (Total Annual Costs / Emissions Reduction)	
Total Annual Costs:	**$16,365,571**
NOx Emissions - Reduction (TPY):	1918.42
Cost Effectiveness ($/Ton):	**$8,531**

Exelon Generation
Croydon Station
RACT II Control Technology Cost Evaluation
Table A-8: SCR Supporting Calculations

Electricity Cost Calculation:

No. of simple cycle units	8	#	
Ammonia injection and recirculation pumps, dilution air fan, and heaters	175	kW/CT	Estimated from vendor (GE) communication considering heater for rapid start
Power required for tempering air fans	150	kW/CT	Vendor (GE) communication
Total load per CT	325	kW/CT	
Annual hours of operation	8760	hr/yr	
Average capacity factor for site	20.0%		Calculated
Expected annual hour of operations for pumps	1752	hr/yr	
Annual power consumption for ammonia system (parasitic load)	4,555	MW-hr/yr	Calculated

Derating of Unit for SCR Pressure drop

Estimated pressure drop in SCR	12.00	inches wg Vendor (GE) Data	
Derating of unit	0.42%	per 4 inch	Vendor (GE) communication
Estimated derating of unit	1.26%	per CT	
Rating of each CT	64.00	MW/CT	
Loss in capacity for all 8 CTs at 100% CF	6.45	MW/ for 8 CTs	
Estimated average capacity factor	20.0%		
Estimated annual operational time	1752	hrs/yr - site wide - for each of 8 CTs	
Estimated annual loss of capacity	11303	MW-hr/yr	

19% Aqueous Ammonia(Reagent) Cost Calculations:

19% Aqueous ammonia usage per CT	0.259	gpm	Vendor (GE) Data: see calculations on the side
No. of CTs operating	8	#	
19% aqueous ammonia usage rate for site per minute	2.07	gpm	
19% aqueous ammonia usage rate for site per hour	124.44	gph	
Total hours per year	8760	hrs/yr	
Site average capacity factor	20.0%		TV permit
Annual 19% aqueous ammonia usage rate	218027	gall/yr	for all 8 CTs at site average CF
Density of 19% aqueous ammonia	7.75	lbs/gal	Based on 19% aqueous ammonia specific gravity of 0.929 and density of water as 8.345 lbs/gal
Annual weight of 19% aqueous ammonia delivered for all CTs	1690253	lbs/yr	
Delivered cost of 19% aqueous ammonia	0.451	$/lb	Site data
Annual cost of 19% aqueous ammonia	$762,304	per year	Calculation

GE considered NOx removal of	90%	GE Proposal
Ammonia usage rate	0.5	gpm per CT - GE Proposal
Required control per presumptive RACT	46.7%	
Revised ammonia usage rate	0.2593	gpm per CT

Exelon Generation
Croydon Station
RACT II Control Technology Cost Evaluation
Table A-8: SCR Supporting Calculations

Labor Costs

Operating Labor

Annual operating labor requirements	2000	hrs/yr	
Site specific labor costs for operating labor	73.80	$/hr	
Annual operating labor cost	$147,607	$/yr	

Maintenance labor

Annual maintenance labor requirements per shift for site	52	hrs/yr	
Site specific labor costs for operating labor	73.80	$/hr	
Annual operating labor cost	$3,838	$/yr	

Supervisory Labor:

Supervisory Labor hours	205	hr/yr	10%	of operating & maintenance labor
Supervisory labor rate	$82.79	$/hr		
Supervisory Labor cost	$16,989	$/yr		

Total labor cost	$168,434	$/yr	

Maintenance Material & Inspection Cost

Maintenance material cost for site per year	$59,900	per yr	Same as 2012 RACT Study
Inspection Cost for Site per 3 years	$73,000	per 3 years	Same as 2012 RACT Study
Inspection Cost for Site per year	$24,333	per year	

Fuel Penalty Cost:

There is no fuel penalty costs. Costs due to derating already considered.

Capacity Change Credit

The SCR does not increase output of the units. Therefore, capacity change credit is not calculated.

ATTACHMENT C

ECONOMIC FEASIBILITY ANALYSIS

Constellation
Croydon Generating Station
RACT III Control Technology Cost Evaluation
Table C-1: Summary of Results

Summary of Results

Item	Water Injection
Site Average Capacity Factor	**20%**
Total Direct Costs (TDC)	$27,784,662
Total Indirect Installation Costs (TIIC)	$10,021,740
TOTAL INSTALLED COST (TIC)	$37,806,402
Total Utilities Cost	$931,820
Additional Operation and Maintenance (O&M) Cost	$262,667
Fuel Penalty	$5,327,955
TOTAL DIRECT (O&M) COSTS	$6,522,442
Additional Total Direct and Indirect Annual Costs (TIIC)	$13,337,396
Capital Recovery Cost	$4,440,726
TOTAL ANNUAL COSTS	$17,778,122
NOx Emissions - Reduction (TPY):	1918.42
Cost Effectiveness ($/Ton):	**$9,267**

Constellation

Croydon Generating Station

RACT III Control Technology Cost Evaluation

Table C-2: Basis for Calculations

Parameter	Value	Units	Reference/Basis
Unit Description:			
Unit Type	GE Frame 7B Simple Cycle		
Number of units	8		
CT Load	64	MW	10 Deg F - Winter Condition (Note: 49 MW in summer)
Fuel	Fuel oil #2		
Maximum Heat Input at 10 F ambient	838	mmbtu/hr	Croydon TV permit
NOX Permit Limit	0.7	lb/mmbtu	Croydon TV permit
NOX Permit Limit	586.6	lb/hr	Croydon TV permit
NOX Permit Limit at 100% CF per CT	2569	tpy/CT	calculated
NOX Permit Limit at 100% CF for all 8 CTs	20554	tpy/all 8 CTs	calculated
Permitted capacity factor for each CT	20%		TV permit
NOX Permit Limit at site average CF for all 8 CTs	4111	tpy/all 8 CTs	calculated
Design Control Condition:			
Baseline Uncontrolled Emissions	180	ppmvd @15% O2	Estimated based on lbs/MMBTU limit in TV permit
	0.700	lbs/MMBTu	Title V permit
Presumptive RACT	96	ppmvd @15% O2	PADEP 129.112(g)(2)(ii)(C) Presumptive RACT
	0.373	lbs/MMBTu	calculated
NOx Control per CT	0.327	lbs/MMBTu/CT	calculated
% control	46.7%		calculated
Annual NOx Controlled at 100% capacity factor	1199.01	tpy/CT	calculated
Permitted Capacity Factor	20%	each	
Average capacity factor for site	20%		
Annual NOx Controlled at permitted capacity factor	239.80	tpy/CT	calculated
No. of units at Facility	8		
Total NOx Controlled at Permitted Capacity Factors	1918.42	tpy for all 8 CTs	calculated
Labor Requirements			
Hourly Cost of Operation Labor	$73.80	per hour	Based on annual burdened rate of $147607 and 2000 hrs/yr
Hourly Cost of Maintenance Labor	$73.80	per hour	Based on annual burdened rate of $147607 and 2000 hrs/yr
Hourly cost of supervisory labor	$82.79	per hour	Based on annual burdened rate of $165,585 and 2000 hrs/yr
Estimated annual operating labor at site - Water Injection	2000	hrs/yr	Estimated 2000 hrs per year of operation - one (1) operator present during operation
Estimated annual maintenance labor at site - Water Injection	52	hrs/yr	Routine and emergency maintenance; Station is curremtly unmanned
Estimated annual operating labor at site - SCR	2000	hrs/yr	Estimated 2000 hrs per year of operation - one (1) operator present during operation
Estimated annual maintenance labor at site - SCR	52	hrs/yr	Routine and emergency maintenance; Station is curremtly unmanned
Estimated supervisory labor as percentage of op/main labor	10%		Estimated
Economic Factors			
Life of Units	20	years	
Construction Period - water Injection	1	year	Site-specific estimate based on staging of construction
State tax (PA)	6%	Pennsylvania state tax	
Local tax	0%	Outside Philadelphia	
Interest during construction	4.7%	Constellation Data	
Interest on Capital	10.0%	Constellation Data	
Reagent/Fuel			
Delivered Demin Water Cost	$13.00	$/1000 gal	Based on Constellation data for similar sites
Fuel oil heating value	137560	BTU/Gallon	TV Permit
Delivered #2 Fuel Oil Cost	$3.12	$/gallon	Constellation data
Electricity cost for site	$183.08	$/MWH	Site Data
Performance Impacts			
Estimated net heat rate increase for water injection	2.00%	Estimated from vendor (GE) communication	

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Table C-3: Capital Costs for Water Injection

Item			Basis	Unit Cost	Subtotal	Total
DIRECT COSTS						
• **Purchased Equipment**						
Purchased Equipment (PE)					$16,687,485	
(8) Water injection system GE supply			GE proposal	$9,920,000		
Laser scan survey (total for all units)			GE proposal	$139,236		
(8) GE Mark Vie controls upgrade			GE proposal	$3,936,000		
(8) NOx analyzers @$50k each			Engr Estimate	$492,000		
(3) On-site Monitoring Lite Instrumentation			GE proposal	$47,749		
(2) 1 million gallon demineralized water storage tanks & pumps			Engr Estimate	$2,152,500		
Freight & Tax Subtotal					$1,835,623	
Freight	5.0%	assumed	% of PE	$834,374		
Sales Tax	6.0%	Site	% of PE	$1,001,249		
Local tax	0.0%					
Purchased Equipment Cost (PEC)					**$18,523,108**	
• **Direct Installation Cost**						
Foundations & Supports	8.0%	OAQPS	% of PEC		$1,481,849	
Handling and Erection	20.0%		% of PEC	Eng Estimate for site	$3,704,622	
Site Prep including relocation of interferences	10.0%	OAQPS	% of PEC		$1,852,311	
Buildings	0.0%		% of PEC	None needed	$0	
Electrical (MCC, wiring, control dashboards)	4.0%	OAQPS	% of PEC		$740,924	
Piping (All including recirculation except from vendor)	2.0%	OAQPS	% of PEC		$370,462	
Insulation, heat tracing	4.0%		% of PEC		$740,924	
Painting	2.0%		% of PEC		$370,462	
Direct Installation Cost (DIC)					**$9,261,554**	
Total Direct Costs (TDC)						**$27,784,662**
INDIRECT INSTALLATION COSTS						
• **Engineering and Project Management**	10.0%	OAQPS	% of PEC		$1,852,311	
• **Construction and Field Expenses**	5.0%	OAQPS	% of PEC		$926,155	
• **Contractor Fees**	10.0%	OAQPS	% of PEC		$1,852,311	
• **Start-up**	2.0%	OAQPS	% of PEC		$370,462	
• **Performance Test including initial RATA**			Estimate		$10,000	
• **Contingencies**	20.0%	OAQPS	% of PEC		$3,704,622	
• **Interest During Construction**			TDC*I*n		$1,305,879	
Construction Period (n)	1	Years				
Interest Rate (I)	4.7%		Constellation data			
Total Indirect Installation Costs (TIIC)						**$10,021,740**
TOTAL INSTALLED COST (TIC)						**$37,806,402**

Basis:
1: Retrofit of eight (8) GE 7B combustion turbines. to reduce NOx to 96 ppmvd @15% O2 (RACT Presumptive Limit).
2: Cost of water injection system including injection skid, piping from skid to combustors, new shower head liquid fuel nozzles, revised control curve, and laser scan survey for developing system layout from General Electric October 7, 2016 budgetary proposal, updated in December 2022.
3: Cost of controls upgrade to GE Mark VIe required for GE to incorporate water injection control program and associated combustor tuning per GE October 7, 2016 budgetary price; GE price includes hardware and installation.
4: Cost of demineralized water receiving and storage system (tank sized for maximum 144 hours of full load operation of all eight units) from engineering estimates.
5: All other costs are based on either percentages for generic plants per OAQPS manual or engineering judgement based on site specific data.

Notes

Cost for GE Mark Vie controls upgrade per combustion turbine =	$492,000	Updated value from GE 12/2022
Cost for GE water injection scope of supply per combustion turbine including the revised control curve=	$1,240,000	Updated value from GE 12/2022
Cost for site laser scan survey =	$139,236	Updated value from GE 12/2022
Cost to Install GE remote monitoring to maintain required reliability	$47,749	Updated value from GE 12/2022
Full load water injection rate per combustion turbine (GE Data)=	27400	lb/h
Full load water usage with all Combustion turbines operating at full load =	219200	lb/h
	438	gpm
Minimum demineralized water storage requirement =	1,892,374	gallons

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Table C-4: Operating and Annualized Costs for Water Injection

Item	Variables	Basis	Unit Cost	Subtotal	Total
Total Direct Costs (TDC)	*(Calculated on previous table)*				**$27,784,662**
TOTAL INSTALLED COST (TIC)	*(Calculated on previous table)*				**$37,806,402**
ANNUAL COSTS					
• **Utilities Cost**				$333,199	
Utility Rate	183.077 $/MW-hr	estimated			
Capacity	1,820 MW-hr/yr				
• **Demin water Cost**				$598,621	
Total Utilities Cost					**$931,820**
• **Additional Operation and Maintenance (O&M) Cost**					
Annual Maintenance Labor Cost				$3,838	
Annual operating Labor Cost				$147,607	
Annual supervosry Labor cost				$16,989	
Annual testing cost including RATA			estimate	$10,000	
Annual Maintenance Material Cost				$59,900	
Annual Inspection Cost				$24,333	**$262,667**
• **Fuel Penalty**					
Additional fuel cost for compensating higher heat rate				$5,327,955	**$5,327,955**
• **Capacity Change Credit**				$0	**$0**
Total Direct (O&M) Cost					**$6,522,442**
ADDITIONAL INDIRECT ANNUAL COSTS					
• **Overhead**	60%	% of O&M - OAQPS			**$3,913,465**
• **Administrative Charges**	2%	% of TCI - OAQPS			**$756,128**
• **Annual Contingency**	5%	% of TDC - OAQPS			**$1,389,233**
• **Property Taxes**	1%	% of TCI - OAQPS			**$378,064**
• **Insurance**	1%	% of TCI - OAQPS			**$378,064**
Total Additional Indirect Costs					**$6,814,954**
Additional Total Direct and Indirect Annual Costs (TIIC)					**$13,337,396**
• **Capital Recovery Cost**		TCI*CRF - OAQPS			**$4,440,726**
Life (n)	20	assumed			
Interest Rate (i)	0.10	Constellation Input			
Capital Recovery Factor (CRF)	0.1175	$(i*(1+i)^n)/((1+i)^n-1)$			
TOTAL ANNUAL COSTS					**$17,778,122**

COST EFFECTIVENESS ANALYSIS (Total Annual Costs / Emissions Reduction) based on Average Permitted Capacity Factor of 23.8%	
Total Annual Costs:	**$17,778,122**
NOx Emissions - Reduction (TPY):	1918.42
Cost Effectiveness ($/Ton):	**$9,267**

Constellation
Croydon Generating Station
RACT III Control Technology Cost Evaluation
Table C-5: Water Injection Supporting Calculations

Electricity Cost Calculation:

No. of combustion turbines	8	#	Comments
Demineralized Water Tank Pumps, power	170	hp	Required water pressure at water injection skid: 15-65 psig per GE; full load water injection rate is 438 gpm; pressure at combustor showerhead estimated at 200 psig
Annual hours of operation	8760	hr/yr	
Average capacity factor for site	20.0%		TV permit
Expected annual hour of operations for pumps	1752	hr/yr	
Annual power consumption for pumps	1,777	MW-hr/yr	Calculated
Demin water storage tank heaters	2	#	
Tank heater power	30	kw	Tank heater average winter electric usage
Annual hours of operation winter only	720	hr/yr	4 months in a year (winter) - 6 hours a day (during night when ambient is <32 F)
Annual power consumption heater	43	MW-hr/yr	Calculation
Total Additional Parasitic Power Requirements	1,820	MW-hr/yr	
Cost of electricity Generation at site:	$183.08	per MW-hr	Site data
Annual electricity cost:	$333,199	per year	Calculation

Demineralized Water Cost Calculations:

Water usage rate per CT	27400	lb/hr	Vendor (GE) Data
No. of CTs operating	8	# of units	
Total water usage at site	219200	lbs/hr	
Total hours per year	8760	hrs/yr	
Site average capacity factor	20.0%		TV permit
Annual water usage rate	384038400	lbs/yr	
	46048	1000 gals/yr based on water density of 8.34 lbs/gal	
Delivered cost of Demin water	13	$/1000 gal	Based on Constellation data for similar sites
Annual cost of water	$598,621	per year	Calculation

Labor Costs

Operating Labor

Annual operating labor requirements per shift for site	2000	hrs/yr	Estimated 2000 hrs per year of operation - one (1) operator present during operation
Site specific labor costs for operating labor	$73.80	$/hr	site data
Annual operating labor cost	$147,607	$/yr	

Maintenance labor

Annual maintenance labor requirements per shift for site	52	hrs/yr	Routine and emergency maintenance; Station is curremtly unmanned
Site specific labor costs for operating labor	$73.80	$/hr	Site data
Annual operating labor cost	$3,838	$/yr	

Supervisory Labor:

Supervisory Labor hours	205	hr/yr	10%	of operating & maintenance labor
Supervisory labor rate	$82.79	$/hr		
Supervisory Labor cost	$16,989	$/yr		

Total labor cost	$168,434	$/yr	

Maintenance Material & Inspection Cost

Maintenance material cost for site per year	$59,900	per yr	Same as 2012 RACT Study
Inspection Cost (combustion system) for Site per 3 years	$73,000	per 3 years	Same as 2012 RACT Study
Annual inspection cost	$24,333	per year	calculated

Fuel Penalty Cost:

Net estimated heat rate increase at NOx limit of 96 ppmvd @15% O2	2.00%	Based on vendor (GE) communication	
Rating of each simp0le cycle unit	838	MMBTU/hr	
Capacity factor for simple cycle units	20%		
Average permitted capacity factor for station	20%		
Total annual heat input for station at site average capacity factor	11745408	MMBTU/yr	basis: 8 units
Additional heat input due to heat rate increase due to water injection	234908	MMBTU/yr	incremental value due to increase in heat rate
Fuel oil high heating value	137560	Btu/gal	Station TV Permit Data
Additional fuel oil requirement	1707678	gal/yr	
Delivered cost of fuel oil at site	$3.12	$/gal	Site data: Ref John Tissue email dated October 10, 2016
Additional fuel cost at site for all 8 CTs	$5,327,955	$/yr	for all 8 CTS

Capacity Change Credit

Capacity change credit is the revenue gained by the facility due to increased output of the facility for operating water injection. The facility plans to maintain the permitted capacity (64 MW) because the safety and operability impacts of higher generation capacity on downstream electrical equipment are unknown at this time. The facility will increase the fuel input to compensate lower heat rate as shown above under Fuel Penalty Cost. Therefore, capacity change credit is not calculated.

From: Whelton, Jeffrey J (GE Gas Power) <jeffrey.whelton@ge.com>
Sent: Wednesday, December 14, 2022 2:32 PM
To: Hatton III, Albert Miller M:(Constellation Power - TSA) <Albert.Hatton@constellation.com>; Del Grosso, Anthony:(Constellation Power) <anthony.delgrosso@constellation.com>
Subject: Updated 2022 Estimates. FW: GE proposals

Hello Al, Tony:

Below are the updated 2022 estimates for the SCR System and Water Injection System.

All CPI Inflation 2016-2022: +23%
Series Title: PPI Commodity data for Metals and metal products, not seasonally adjusted 2016-2022: +57%
PPI Commodity data for Metals: 60%
All CPI Inflation: 40%
Total Application Escalation 2016-2022: 43.4%

2022 7B SCR System Budget Estimate: $17.52M
2022 Water Injection System Budget Estimate Per Gas Turbine: $1.24M

The budgetary estimates and scopes are subject to change. The estimates are intended only to assist in CEG's budget planning and does not constitute a firm quotation on the part of GE.

Thank you.

Jeff

Jeff Whelton
Account Manager
GE Power Services
jeffrey.whelton@ge.com
708-427-8507

ATTACHMENT D

CERTIFICATION

TRUTH, ACCURACY, AND COMPLETENESS CERTIFICATION BY RESPONSIBLE OFFICIAL		
I certify that, based on information and belief formed after reasonable inquiry, the statements and information contained in the attached RACT III case-by-case proposal are true, accurate and complete.		
Signature		Date 12/28/2022
Responsible Official Name	Joseph M. Dick	
Responsible Official Title	General Manager	