

NORTH CAROLINA DIVISION OF AIR QUALITY			Region: Fayetteville Regional Office		
Air Permit Review – Renewal			County: Cumberland		
Permit Issue Date: XXXX, 2008			NC Facility ID: 2600094		
			Inspector's Name: Robert Hayden		
			Date of Last Inspection: 08/21/2007		
			Compliance Code: 3/In Compliance - Inspection		
Facility Data			Permit Applicability (this application only)		
Applicant (Facility's Name): Public Works Commission, Butler-Warner Generation Plant			SIP: 15A NCAC 2Q .0513		
Facility Address: Public Works Commission - Butler-Warner Generation Plant 2274 Custer Avenue Fayetteville, NC 28306			NSPS: N/A		
			NESHAP: N/A		
			PSD: N/A		
			PSD Avoidance: N/A		
			NC Toxics: N/A		
			112(r): N/A		
			Other: N/A		
SIC: 4911/ Elec & Other Services Combined					
NAICS: 221112 / Fossil Fuel Electric Power Generation					
Facility Classification: Before: Title V After: Title V					
Fee Classification: Before: Title V After: Title V					
Contact Data					
Facility Contact		Authorized Contact		Technical Contact	
John Ezzelle, Jr Environmental Compliance Specialist 955 Old Wilmington Rd. Fayetteville NC, 28301 (910) 223-4118		Allen Wallace Power Plant Supervisor P. O. Drawer 1089 Fayetteville NC, 28302 (910) 223-4813		Allen Wallace Power Plant Supervisor P. O. Drawer 1089 Fayetteville NC, 28302 (910) 223-4813	
Review Engineer: Booker Pullen			Application Data		
Regional Engineer: Robert Hayden			Application Number: 2600094.07A		
Review Engineer's Signature:			Date Received: 02/19/2007		
Begin Date: October 30, 2007			Application Type: Renewal		
			Application Schedule: TV-Renewal		
			Existing Permit Data		
			Existing Permit Number: 03029/T14		
			Existing Permit Issue Date: 03/30/2007		
			Existing Permit Expiration Date: 11/30/2007		
			Comments / Recommendations:		
			Issue 03029/T15		
			Permit Issue Date: XXXX, 2008		
			Permit Expiration Date: XX, 2013		

I. **Introduction/Description:** This facility is requesting "Renewal" of the existing Title V Permit. Application 2600094.07A was received by the Division of Air Quality (DAQ) on February 19, 2007. The application was considered complete on this date.

The Butler-Warner Generation Plant for the Public Works Commission (PWC) of Fayetteville, NC is designed to provide electric generation to meet PWC load during peak loading situations, and on short notice, and to provide for sales to other utilities. This is a nominal 280 megawatt capacity plant. There are eight (8) combustion turbine generators available for electric generation (ID Nos. GT-1 through GT-8). Each turbine generator nominally produces approximately 26-29 megawatts of power, for a total of 208 megawatts. The additional 72 megawatts is produced by a single turbine generator. This steam turbine generator is powered by the steam generated in three heat recovery generators (HRSG) from the waste heat of six of the gas turbines (two gas turbines per HRSG, GT-1 & 8, GT-2 & 3, and GT-6 & 7). The exhaust heat from the turbines goes through the HRSGs to produce the steam and then the steam goes through the steam turbines.

All eight combustion turbine generators utilize a water-injection system for the reduction of adiabatic flame temperatures and resulting thermal NO_x (nitrogen oxides) generation. Unit No. 8 is an NSPS source that mandates NO_x reduction; the other seven units have the same NO_x reduction system. The water injection system does not begin immediately when the turbine generators start up. Water injection is designed to commence at a certain load so that it does not interfere with operation during start-up/ramp-up. For natural gas combustion, the water injection system comes on at 15 megawatts.

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I. Introduction/Description: (continued)

A water-demineralization plant provides water for this process. The used resins generated from this process are taken off-site, regenerated, and sold to a customer with less stringent resin specifications.

TURBINE GENERATOR CONTROL ROOMS: One staff member is assigned to walk through and monitor each of the turbine generator control rooms. Each turbine generator control room is equipped with a control panel that has real-time data for the fuel consumption and ratio of water to fuel. PWC has installed software to use the water injection/fuel injection ratio.

FACILITY CONTROL ROOM: The facility stores this computer data (approximately 1 month of data per storage tape) in a small room located adjacent to the facility control room. If the system injects more or less water than is acceptable an alarm goes off in the turbine generator control room and the facility control room. In the facility control room a red light flashes on the wall and a red message flashes on the control room computer. Personnel respond to this alarm by first checking the water pump to the turbine generator. If the problem occurs on GT-8 and cannot be identified and solved immediately (usually within 4 to 10 minutes of notification), the unit will be shut down to prevent excess emissions.

II. Purpose of this application (2600094.07A):

Renewal of existing Title V Air Permit and to satisfy the requirement in 15A NCAC 22Q .0501(c)(2) in which the modification permitted in the previous revision (T14) will be sent to the 30 day public notice and 45 day EPA review in order that the requirements for this modification become Federally Enforceable.

III. Changes to existing Title V Permit No. 03029T14 per application (2600094.07A):

Old Page No.	New Page No.	Condition No.	Changes
Page 1	Page 1	Cover letter	Changed date, revised permit number, added "Renewal" language to cover page, removed the requirement to submit an application within twelve months
Page 2	Page 2	Cover letter	Changed date on letter, changed effective date of permit, Changed the expiration date of the permit, added EPA Region IV to "c" list
Page 3	Page 3	Table	Updated the "changes to the permit" table to reflect the changes per this application
Page 4	Page 4	Insignificant activities table	Changed permit revision to T15
Body of the permit			
Page 1	Page 1	Cover page	Changed: permit revision, "replaces permit" date, effective date of permit, application number, permit issue date, complete application date, and removed renewal date
Page 2	Page 2	Table of Contents	Removed Part II Section
All pages	All pages	Heading of page	Changed the revision no. of Permit to T15
Page 3	Page 3	Specific Limitation and Conditions	Removed * from beside control device No. GT2C-1
Page 4	Page 4	Specific Limitation and Conditions	Removed footnote from the bottom of table
Pages 5 -10	N/A	Specific Limitation and Conditions	Removed 40 CFR 52 Subpart II references from the permit, because 2D .0521 is now Federally Enforceable Removed 40 CFR 52 Subpart II references from the permit, because 2D .0521 is now Federally Enforceable
Page 9	Page 8	Specific Limitation and Conditions	Added "NSPS Subpart GG" to description in Condition "C"
Pages 10-11	Page 9-12	Specific Limitation and Conditions	Revised NSPS, Subpart GG requirements, removed the last sentence of Section 2.1.C.3.f.i from the permit
Pages 12-13	N/A	Multiple Emissions	Removed the NOx allocation tables
N/A	Pages 13-14	Multiple Emissions	Added CAIR conditions
Pages 23-25	N/A	Part II	Removed Part II Section from the permit
Pages 14-22	Page 15-23	General Conditions	Added revised General Conditions

IV. Statement of Compliance:

The DAQ has reviewed the compliance status of this facility. On its latest inspection, performed on August 8, 2007, by Mr. Robert Hayden of the Fayetteville Regional Office, the facility appeared to be in compliance with all applicable requirements. The applicant has certified that the facility will be in compliance with all applicable requirements at the time of permit issuance and will continue to comply with these requirements. The applicant has also certified that the facility will be in compliance with any applicable requirements taking effect during the term of the permit and will meet such requirements on a timely basis.

V. Summary Of Emission Sources For Which This Significant Modification Is Being Issued

The following table contains a summary of all permitted emission sources and associated air pollution control devices and appurtenances:

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
GT-1	one (1) natural gas/ No. 2 fuel oil-fired simple-cycle/combined-cycle turbine generator (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate), with exhaust gas directed through one heat recovery steam generator (HRSG-2) during combined-cycle operation or to the atmosphere through an exhaust stack during simple-cycle operation	GT1C-1	one (1) NO _x -reducing water injection system installed on the turbine generator
GT-2	one (1) natural gas/ No. 2 fuel oil-fired simple-cycle/combined-cycle turbine generator (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate), with exhaust gas directed through one heat recovery steam generator (HRSG-1) during combined-cycle operation or to the atmosphere through an exhaust stack during simple-cycle operation	GT2C-1	one (1) NO _x -reducing water injection system installed on the turbine generator
GT-3	one (1) natural gas/ No. 2 fuel oil-fired simple-cycle/combined-cycle turbine generator (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate),with exhaust gas directed through one heat recovery steam generator (HRSG-1) during combined-cycle operation or to the atmosphere through an exhaust stack during simple-cycle operation	GT3C-1	one (1) NO _x -reducing water injection system installed on the turbine generator
GT-4	one (1) natural gas/No. 2 fuel oil-fired simple-cycle turbine generators (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate each)	GT4C-1	one (1) NO _x -reducing water injection system installed on the turbine generator
GT-5	one (1) natural gas/No. 2 fuel oil-fired simple-cycle turbine generators (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate each)	GT5C-1	one (1) NO _x -reducing water injection system installed on the turbine generator
GT-6	one (1) natural gas/ No. 2 fuel oil-fired simple-cycle/combined-cycle turbine generator (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate), with exhaust gas directed through one heat recovery steam generator (HRSG-3) during combined-cycle operation or to the atmosphere through an exhaust stack during simple-cycle operation	GT6C-1	one (1) NO _x -reducing water injection system installed on the turbine generator

V. Summary Of Emission Sources For Which This Significant Modification Is Being Issued - Continued

The following table contains a summary of all permitted emission sources and associated air pollution control devices and appurtenances:

Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
GT-7	one (1) natural gas/ No. 2 fuel oil-fired simple-cycle/combined-cycle turbine generator (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate), with exhaust gas directed through one heat recovery steam generator (HRSG-3) during combined-cycle operation or to the atmosphere through an exhaust stack during simple-cycle operation	GT7C-1	one (1) NO _x -reducing water injection system installed on the turbine generator
GT-8 NSPS, Subpart GG	one (1) natural gas/ No. 2 fuel oil-fired simple-cycle/combined-cycle turbine generator (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate), with exhaust gas directed through one heat recovery steam generator (HRSG-2) during combined-cycle operation or to the atmosphere through an exhaust stack during simple-cycle operation	GT8C-1	one (1) NO _x -reducing water injection system installed on the turbine generator

VI. Emission Source-by-Source Evaluation

This is a 280 megawatt capacity plant. There are eight (8) combustion turbine generators available for electric generation (ID Nos. GT-1 through GT-8). Each turbine generator produces approximately 26-29 megawatts of power, each, for a total of 208 megawatts. The additional 72 megawatts is produced from a single steam turbine that is powered by waste heat from six of the gas turbines (two gas turbines per steam turbine).

The facility operates on natural gas unless there is a curtailment by the supplier, Piedmont Natural Gas. The facility seldom operates on fuel oil. The most significant combustion of fuel oil since 2004 was associated with emissions testing performed during the first half of 2007.

This turbine generator utilizes a water-injection system for the reduction of adiabatic flame temperatures and resulting thermal NO_x (nitrogen oxides) generation. The water injection system does not begin immediately when the turbine generator starts up. Water injection is designed to commence at a certain load so that it does not interfere with operation during start-up/ramp-up. For natural gas combustion, the water injection system comes on at 15 megawatts.

- A. Five (5) natural gas/ No. 2 fuel oil-fired simple-cycle/combined-cycle electric utility stationary gas internal combustion turbines (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate each, ID Nos. GT-1, GT-2, GT-3, GT-6, and GT-7), each equipped with water injection for NO_x control, and with exhaust gas directed through one of three heat recovery steam generators (ID Nos. HRSG-1, HRSG-2, or HRSG-3)**
 - 1. 15A NCAC 2D .0516 "Sulfur Dioxide Emissions from Combustion Sources"**
 - 2. 15A NCAC 2D .0521 "Control Of Visible Emissions"**
 - 3. 15A NCAC 2D .1417 "Emission Allocations For Large Combustion Sources"**

No regulatory review is required for the regulations listed above. Regulation 40 CFR 52 Subpart II "North Carolina State Implementation Plan" was removed from the permit because visible emissions regulation 15A NCAC 2D .0521 is now federally enforceable.

4. 15A NCAC 2D .0614 "Compliance Assurance Monitoring" (CAM)

The five (5) natural gas/No. 2 fuel oil-fired simple-cycle/combined-cycle internal combustion turbines (ID Nos. GT-1, GT-2, GT-3, GT-6, GT-7) are exempted from the requirements of Compliance Assurance Monitoring (CAM). Even though the water injection system spray nozzles are considered control devices for NO_x, they are not used to meet any specific emission limit for NO_x.

- A. Five (5) natural gas/ No. 2 fuel oil-fired simple-cycle/combined-cycle electric utility stationary gas internal combustion turbines (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate each, ID Nos. GT-1, GT-2, GT-3, GT-6, and GT-7), each equipped with water injection for NO_x control, and with exhaust gas directed through one of three heat recovery steam generators (ID Nos. HRS_G-1, HRS_G-2, or HRS_G-3) – Continued-

5. 15A NCAC 2D. 0524, “NSPS, Subpart Da” (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978)

Four of the five simple-cycle/combined-cycle internal combustion turbines with steam generating units (ID Nos. GT-1, 2, 3, and 6) each “commenced construction” prior to October 1977. This date is prior to the Subpart D_a applicability date. Therefore, NSPS, Subpart Da does not apply.

The simple-cycle/combined-cycle internal combustion turbine (ID No. GT-7) with steam generating unit requested an applicability determination from the DAQ and the US EPA for the installation of Unit (ID No. GT-7).

The US EPA responded in a letter to the Division of Environmental Management (Mr. Paul R. Wilms), received on June 26, 1989, stating that PWC entered into a contractual obligation (commenced construction) sufficient to avoid NSPS applicability. The EPA noted that PWC would not have been able to void the contract without “significant liability”. Therefore, NSPS Subpart Da does not apply to unit GT-7)

6. 15A NCAC 2D .0530(v) “PSD Applicability”

Regulation 15A NCAC 2D . 0530 (v) was added in permit revision T15 in which a permit modification was requested to install breech-loaded fuel nozzles (BLFN) on unit 2 (Unit ID No. GT-2) with a goal of achieving higher NO_x emission reductions. The nozzles represent an enhanced emissions control measure that will assure continued compliance with the facility’s NO_x allocation under the current NO_x SIP Call rule and future allocations under CAIR program. These new nozzles have a higher water injection rate than the current nozzles on turbine unit GT-2. The usage and installation of these new nozzles **does** constitute a physical change with an associated increase in CO emissions.

Unit 2 is the only turbine to add the new nozzles. The other turbines will be included at some later date, which would appear to require a PSD permit application due to the *total* potential increase in CO emissions from the other 7 turbines. This modification was processed as a 501(c)(2) modification that required submittal of another application within 12 months of operation of turbine G-2 with the new nozzles. **This requirement has now been met with the submittal of this renewal application (APP2600094.07A).**

Carbon Monoxide Emissions Increase due to modification:

This facility is major for PSD, therefore the emissions increases of the criteria pollutants must be less than the significant emission rates in accordance with 40 CFR §51.166 (b)(23)(i). The only expected increase of a criteria pollutant will be carbon monoxide. The significant level of increase for PSD purposes is 100 tons per year.

Emission factors for natural gas fired in turbine:

TSP = 6.60E-03 lbs TSP/million Btu heat input (AP-42, table 3.1-2a)
PM10 = 6.60E-03 lbs PM10/million Btu heat input (AP-42, table 3.1-2a)
PM_{2.5} = 4.70E-03 lbs PM2.5/million Btu heat input (AP-42, table 3.1-2a)
SO₂ = 3.40E-03 lbs SO₂/million Btu heat input (AP-42, table 3.1-2a, note “h”)
NO_x = 0.31 lbs NO_x/million Btu heat input (M20 Test for Low Mass Emission in December 2003)
CO = 0.37 lbs CO/million Btu heat input (Sampling data)
VOC = 0.011 lbs VOCs/million Btu heat input (AP-42, table 3.1-2a)

- A. **Five (5) natural gas/ No. 2 fuel oil-fired simple-cycle/combined-cycle electric utility stationary gas internal combustion turbines (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate each, ID Nos. GT-1, GT-2, GT-3, GT-6, and GT-7), each equipped with water injection for NOx control, and with exhaust gas directed through one of three heat recovery steam generators (ID Nos. HRSG-1, HRSG-2, or HRSG-3) - Continued-**

5. 15A NCAC 2D .0530(v) “PSD Applicability” – continued-

Emission factors for No. 2 fuel oil fired in turbine:

- TSP = 1.15E-02 lbs TSP/million Btu heat input (AP-42, table 3.1-2a)
- PM10 = 1.15E-02 lbs PM10/million Btu heat input (AP-42, table 3.1-2a)
- PM_{2.5} = 7.20E-03 lbs PM2.5/million Btu heat input (AP-42, table 3.1-2a)
- SO₂ = 0.0505 lbs SO₂/million Btu heat input (AP-42, table 3.1-2a, note “h”)
- NOx = 0.36 lbs NOx/million Btu heat input (M20 Test for Low Mass Emission in December 2003)
- CO = 0.08 lbs CO/million Btu heat input (Sampling data)
- VOC = 0.004 lbs VOCs/million Btu heat input (AP-42, table 3.1-2a)

Maximum emission for Either Fuel fired in the turbine:

- TSP (from fuel oil) = 0.0115 lbs TSP/million Btu heat input (AP-42, table 3.1-2a)
- PM10 (from fuel oil) = 0.0115 lbs PM10/million Btu heat input (AP-42, table 3.1-2a)
- PM2.5 (from fuel oil) = 0.0072 lbs PM2.5/million Btu heat input (AP-42, table 3.1-2a)
- SO₂ (from fuel oil) = 0.0505 lbs SO₂/million Btu heat input (AP-42, table 3.1-2a, note “h”)
- NOx (from fuel oil) = 0.36 lbs NOx/million Btu heat input (M20 Test for Low Mass Emission in December 2003)
- CO (from gas) = 0.37 lbs CO/million Btu heat input (Sampling data)
- VOC (from gas) = 0.011 lbs VOCs/million Btu heat input (AP-42, table 3.1-2a)

Unit 2 CO emissions from the past 5 years as reported on annual inventories

Table 1:

Year	Natural gas	No. 2 fuel oil	Total Emissions
2001	2.13 tpy	2.41 tpy	4.53 tpy
2002	6.21 tpy	0.86 tpy	7.08 tpy
2003	0.88 tpy	4.64 tpy	5.52 tpy
2004	2.07 tpy	1.08 tpy	3.15 tpy
2005	2.56 tpy	0.99 tpy	3.55 tpy

The average tons per year for the highest to consecutive years is taken from the years 2002 and 2003
7.08 tpy + 5.52 tpy = 6.30 tpy

Projected Annual Emissions Using the BLFN Upgrade

Site specific Test data: Table 2

BWGP CO Testing Data								
Power (MW)	Fuel type	Fuel flow (lb/sec)	Water flow (lbs/sec)	IGV Angle (degrees)	Exhaust (degrees F)	CO (meas) (ppm)	O ₂ (meas) (ppm)	CO (lbs/mmBtu)
5	NG	1.63 lbs/sec	0.00 lbs/sec	85 degrees	558 degrees F	87.60 ppm	18.53 ppm	1.03 *
10	NG	2.16 lbs/sec	0.00 lbs/sec	85 degrees	662 degrees F	17.70 ppm	17.85 ppm	0.20 *
15	NG	2.89 lbs/sec	1.24 lbs/sec	85 degrees	686 degrees F	33.76 ppm	17.44 ppm	0.37 **
20	NG	3.39 lbs/sec	1.36 lbs/sec	85 degrees	789 degrees F	18.80 ppm	16.80 ppm	0.20 **
25.5	NG	4.11 lbs/sec	1.37 lbs/sec	85 degrees	916 degrees F	5.40 ppm	15.90 ppm	0.05 **
5	Distillate	2.12 lbs/sec	1.36 lbs/sec	85 degrees	550 degrees F	253.46 ppm	18.49 ppm	2.97 *
10	Distillate	2.79 lbs/sec	1.48 lbs/sec	85 degrees	611 degrees F	6.80 ppm	18.00 ppm	0.08 **
15	Distillate	3.44 lbs/sec	1.92 lbs/sec	85 degrees	694 degrees F	6.00 ppm	17.30 ppm	0.07 **
20	Distillate	4.17 lbs/sec	2.07 lbs/sec	85 degrees	799 degrees F	4.20 ppm	16.50 ppm	0.04 **
21.8	Distillate	4.53 lbs/sec	2.28 lbs/sec	85 degrees	929 degrees F	5.10 ppm	15.70 ppm	0.05 *

*Data from June 2001 sampling of GT-1 with conventional nozzles (best available comparable data)

**Data from January 2007 GE sampling of GT-2 with BLFN in service

- A. Five (5) natural gas/ No. 2 fuel oil-fired simple-cycle/combined-cycle electric utility stationary gas internal combustion turbines (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate each, ID Nos. GT-1, GT-2, GT-3, GT-6, and GT-7), each equipped with water injection for NOx control, and with exhaust gas directed through one of three heat recovery steam generators (ID Nos. HRSG-1, HRSG-2, or HRSG-3) - Continued-

5. 15A NCAC 2D .0530(v) "PSD Applicability" – continued-

Table 3:

Combustion Turbine No. 2 Historical Heat Input Data					
Year	Natural Gas (mcf)	No. 2 Fuel Oil (gal)	Natural Gas (mmBtu)	No. 2 Fuel Oil (mmBtu)	Total (mmBtu)
2005	165,693	186,560	170,663	25,932	196,595
2004	133,892	205,119	137,909	28,512	166,420
2003	56,738	878,528	58,440	122,115	180,555
2002	402,102	163,397	414,165	22,712	436,878
2001	137,676	455,818	141,807	63,359	205,165
Total			922,984 mmBtu	262,630 mmBtu	1,185,614 mmBtu

Example calculation for Table 3 above:

$$\frac{165,693 \text{ mcf (natural gas)}}{\text{year 2005}} \times \frac{1000 \text{ cf}}{1 \text{ mcf}} \times \frac{1030 \text{ Btu}}{\text{cf (natural gas)}} \times \frac{1 \text{ mmBtu}}{1 \times 10^6 \text{ Btu}} = \frac{170,663 \text{ mmBtu}}{\text{year 2005}}$$

$$\frac{186,560 \text{ gallons (No.2 fuel oil)}}{\text{year 2005}} \times \frac{139,000 \text{ Btu}}{\text{gallon (No.2 fuel oil)}} \times \frac{1 \text{ mmBtu}}{1 \times 10^6 \text{ Btu}} = \frac{25,932 \text{ mmBtu}}{\text{year 2005}}$$

$$17,663 \text{ mmBtu} + 25,932 \text{ mmBtu} = 196,595 \text{ mmBtu}$$

From table 3 on the previous page, the average percentage usages of No. 2 fuel oil and natural gas for years 2001 through 2005 are:

22.15% for No. 2 fuel oil usage (262,630 mmBtu ÷ 1,185,614) and
77.85% for natural gas usage (922,984 mmBtu ÷ 1,185,614)

The average 5 year heat input from Table 3 = 237,123 mmBtu (1,185,614 ÷ 5)

The average 2 highest consecutive years from Table 3 = 321,021 mmBtu {(436878 + 205165) ÷ 2}

Table 4:

Projected Future Actual CO Calculation Using Average of Highest 2 Years Heat Input								
Power Range	Load factor	Gas Heat input	Oil Heat input	Gas CO rate (lbs/mmBtu)	Oil CO rate (lbs/mmBtu)	CO from Gas (tons)	CO from Oil (tons)	Annual CO (tons)
P < 5	0.10	249911 mmBtu	71111 mmBtu	1.03	2.97	13.35 tons	10.88 tons	24.13 tons
5 < P < 10	0.07	249911 mmBtu	71111 mmBtu	0.20	0.08	1.68 tons	0.18 tons	1.86 tons
10 < P < 15	0.12	249911 mmBtu	71111 mmBtu	0.37	0.07	5.53 tons	0.28 tons	5.80 tons
15 < P < 20	0.36	249911 mmBtu	71111 mmBtu	0.20	0.04	8.89 tons	0.56 tons	9.45 tons
P > 20	0.36	249911 mmBtu	71111 mmBtu	0.05	0.05	2.42 tons	0.64 tons	3.06 tons
Total								44.30 tons

Example calculation for Table 4 above for Power Range 10 < P < 15:

$$\frac{0.12 \text{ (load factor)}}{1} \times \frac{249,911 \text{ mmBtu}}{\text{year}} \times \frac{0.37 \text{ lbs CO}}{\text{mmBtu}} \times \frac{1 \text{ ton}}{2000 \text{ lbs CO}} = \frac{5.54 \text{ tons}}{\text{year}} \text{ (firing natural gas)}$$

$$\frac{0.12 \text{ (load factor)}}{1} \times \frac{71,111 \text{ mmBtu}}{\text{year}} \times \frac{0.07 \text{ lbs CO}}{\text{mmBtu}} \times \frac{1 \text{ ton}}{2000 \text{ lbs CO}} = \frac{0.29 \text{ tons}}{\text{year}} \text{ (firing No. fuel oil)}$$

- A. **Five (5) natural gas/ No. 2 fuel oil-fired simple-cycle/combined-cycle electric utility stationary gas internal combustion turbines (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate each, ID Nos. GT-1, GT-2, GT-3, GT-6, and GT-7), each equipped with water injection for NOx control, and with exhaust gas directed through one of three heat recovery steam generators (ID Nos. HRSG-1, HRSG-2, or HRSG-3) – Continued-**

5. 15A NCAC 2D .0530(v) “PSD Applicability” – continued-

The applicant computed the projected future actual emissions using the 2 highest year’s heat input to calculate the potential carbon monoxide emissions (44.30 tons per year) for the Unit No. 2 modification of installing the nozzles with a higher water injection rate. This projected future actual rate was compared with the actual emissions from the most recent annual inventories. A PSD permit is not required at this time because the increase in CO emissions (44.3 tons CO – 6.30 tons CO = 38.00 tons) is less the PSD significant level of 100 tons.

The following regulation applies to this modification since the applicant used the projected actual emissions to avoid the applicability of PSD.

If the owner or operator of a source is using projected actual emissions to avoid applicability of prevention of significant deterioration requirements, the owner or operator shall notify the director of the modification. The notification shall include:

- ** a description of the project,
- ** identification of sources whose emissions could be affected by the project,
- ** the calculated projected actual emissions and an explanation of how the projected actual emissions were calculated,
- ** the calculated baseline emissions and an explanation of how the baseline emissions were calculated,
- and
- ** any netting calculations if applicable.

These items were included in permit application No. 2600094.07A.

If upon reviewing the notification, the DAQ finds that it will cause a prevention of significant deterioration evaluation, then the Director shall notify the owner or operator of his findings. The owner or operator shall not make the modification until it has received a permit issued pursuant to this Rule.

The modification in application 2600094.07A does not trigger PSD.

If a permit revision is not required pursuant to this rule, the owner or operator shall maintain records of emissions related to the modifications for **10 years** if the project involves increasing the emission unit’s design capacity or its potential to emit the regulated NSR pollutant by a significant amount, as defined at 40 CFR 51.166(b)(23)(i), when compared to the pre-modification potential to emit, otherwise these records shall be maintained for **five years**.

The modification in application 2600094.07A does not increase the design capacity of the turbine, however, the potential to emit in accordance with 40 CFR 51.166(b)(23)(i) will be increased. Therefore, this facility is required under 15A NCAC 2D .0530 (v) to keep records for 10 years for the operation of the nozzles in Unit No. 2 (ID No. GT-2).

The following condition was placed in the body of the permit:

In accordance with 15A NCAC 2D .0530 (v), the owner or operator of a source using projected actual emissions to demonstrate that Prevention of Significant Deterioration (PSD) requirements do not apply, shall maintain records of emissions related to the modification for 10 years if the project involves increasing the unit’s potential to emit the New Source Review pollutant (CO) by a significant amount as defined in 40 CFR 51.166(b)(23)(i), when compared to the pre-modification potential-to-emit.

The Permittee may use continuous emissions monitoring data, operational levels, fuel usage data, source test results, or any other readily available data of sufficient accuracy for the purpose of documenting Unit No 2.’s (ID No. GT-2) post-change actual annual utilization.

- A. **Five (5) natural gas/ No. 2 fuel oil-fired simple-cycle/combined-cycle electric utility stationary gas internal combustion turbines (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate each, ID Nos. GT-1, GT-2, GT-3, GT-6, and GT-7), each equipped with water injection for NO_x control, and with exhaust gas directed through one of three heat recovery steam generators (ID Nos. HRSG-1, HRSG-2, or HRSG-3) – Continued-**

5. 15A NCAC 2D .0530(v) “PSD Applicability” – continued-

If the Director of the Division of Air Quality determines that the actual annual utilization rate for Unit No. 2 (ID No. GT-2) for any of the reported 10 years has exceeded the respective projected future annual utilization rate as included in permit application 2600094.07B and the Permittee further determines that this increase in utilization is due to the installation of the breech loaded fuel nozzles (water injection system) on Unit No. 2 (ID No. GT-2) and such increased utilization would have resulted in a significant net emission increase at the time of submittal of application for installation of the breech loaded fuel nozzles (water injection system), the Permittee shall be deemed in violation of 15A NCAC 2D .0530.

6. 15A NCAC 2D .2400 “Clean Air Interstate Rules” (CAIR)

The Five (5) natural gas/No. 2 fuel oil-fired simple-cycle/combined-cycle internal combustion turbines (ID Nos. GT-1, GT-2, GT-3, GT-6, GT-7) are subject to CAIR.

On March 15, 2006 the U.S. Environmental Protection Agency (EPA) promulgated federal implementation plans, or FIPs, for power plants to ensure that the emissions reductions required by the Clean Air Interstate Rule (CAIR) are achieved on schedule. The CAIR requires states to reduce emissions of nitrogen oxides (NO_x) and sulfur dioxide (SO₂) that significantly contribute to fine particle (PM 2.5) and ground-level ozone pollution problems in downwind states. 28 States and the District of Columbia will be required to revise their State Implementation Plans. Each state covered by CAIR may independently determine which emission sources to control and which control measures to adopt. CAIR includes model rules for multi-state cap and trade programs for power plants that states may choose to adopt to meet the required emissions reductions in a flexible and highly cost-effective manner. The rule specifies emissions reductions requirements for SO₂ and NO_x.

The first phase of NO_x reductions starts in 2009 (covering 2009-2014) and the first phase of SO₂ reductions starts in 2010 (covering 2010-2014). The second phase of both SO₂ and NO_x reductions starts in 2015 (covering 2015 and thereafter).

Regulatory language will be added to the permit. See Section VIII of this review.

- B. **Two (2) natural gas/No. 2 fuel oil-fired simple-cycle electric utility stationary gas turbine generators (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate each) each equipped with water injection for NO_x control**
1. **15A NCAC 2D .0516 “Sulfur Dioxide Emissions from Combustion Sources”**
 2. **15A NCAC 2D .0521 “Control Of Visible Emissions”**
 3. **15A NCAC 2D .1417 “Emission Allocations For Large Combustion Sources”**

No regulatory review is required for the regulations listed above. Regulation 40 CFR 52 Subpart II “North Carolina State Implementation Plan” was removed from the permit because visible emissions regulation 15A NCAC 2D .0521 is now federally enforceable.

4. 15A NCAC 2D .0614 “Compliance Assurance Monitoring” (CAM)

The two natural gas/No. 2 fuel oil-fired simple-cycle combustion turbines (ID Nos. GT-4, and GT-5) are exempted from the requirements of Compliance Assurance Monitoring (CAM). Even though the water injection system nozzles are considered a control device for NO_x, they are not used to meet any specific emission limit for NO_x.

5. 15A NCAC 2D. 0524, “NSPS, Subpart Da” (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978)

These two simple-cycle/combined-cycle internal combustion turbines do not include a steam generating unit, therefore, NSPS, Subpart Da does not apply.

6. 15A NCAC 2D .2400 “Clean Air Interstate Rules” (CAIR)

The two (2) natural gas/No. 2 fuel oil-fired simple-cycle internal combustion turbines (ID Nos. GT-4, and GT-5) are subject to CAIR.

On March 15, 2006 the U.S. Environmental Protection Agency (EPA) promulgated federal implementation plans, or FIPs, for power plants to ensure that the emissions reductions required by the Clean Air Interstate Rule (CAIR) are achieved on schedule. The CAIR requires states to reduce emissions of nitrogen oxides (NOx) and sulfur dioxide (SO₂) that significantly contribute to fine particle (PM 2.5) and ground-level ozone pollution problems in downwind states. 28 States and the District of Columbia will be required to revise their state implementation plans. Each state covered by CAIR may independently determine which emission sources to control and which control measures to adopt. CAIR includes model rules for multi-state cap and trade programs for power plants that states may choose to adopt to meet the required emissions reductions in a flexible and highly cost-effective manner. The rule specifies emissions reductions requirements for SO₂ and NOx. The first phase of NOx reductions starts in 2009 (covering 2009-2014) and the first phase of SO₂ reductions starts in 2010 (covering 2010-2014). The second phase of both SO₂ and NOx reductions starts in 2015 (covering 2015 and thereafter).

Regulatory language will be added to the permit. See Section VIII of this review.

C. One (1) natural gas/ No. 2 fuel oil-fired simple-cycle/combined-cycle electric utility stationary gas turbine generator (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate, GT-8)with exhaust gas directed through one heat recovery steam generator (HRSG-2), NSPS Subpart GG

- 1. 15A NCAC 2D .0524 “Standards of Performance For Stationary Gas Turbines”- Sulfur Dioxide**
- 2. 15A NCAC 2D .0521 "Control Of Visible Emissions”**
- 3. 15A NCAC 2D. 0524 “Standards of Performance For Stationary Gas Turbines”- Nitrogen Dioxide**
- 4. 15A NCAC 2D .1417 “Emission Allocations For Large Combustion Sources”**

No regulatory review is required for the regulations listed above. Regulation 40 CFR 52 Subpart II “North Carolina State Implementation Plan” was removed from the permit because visible emissions regulation 15A NCAC 2D .0521 is now federally enforceable. 15A NCAC 2D .0524 will be revised to include the revised 40 CFR Part 60, Subpart GG requirements and the NCDAQ’s current format for monitoring and compliance determinations for a facility that uses the continuous compliance method in lieu of CAM.

Note: The last sentence “Any unit operating hour in which water is injected into the turbine shall be considered an excess emission” in Section 2.1.C.3.f.i was removed from the permit. Compliance testing fro source GT-8 was completed on natural gas fuel at power levels of 3 MW and 11MW with no water injection flow. The NOx concentration were demonstrated during testing to be less than the 89 ppm standard.

5. 15A NCAC 2D. 0524, “NSPS, Subpart Da” (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978)

The simple-cycle/combined-cycle internal combustion turbine (ID No. GT-8) with steam generating unit is not subject to NSPS, Subpart Da because the steam generating unit because fuel in not combusted in the steam generating unit. The heat used to produce steam comes from the exhaust heof the turbine. Per 40 CFR Part 60, Subpart Da, §60.60Da(b)(4), the only emissions resulting from combustion of fuels in the steam-generating unit are subject to this subpart.

5. 15A NCAC 2D .0614 “Compliance Assurance Monitoring” (CAM)

The one natural gas/No. 2 fuel oil-fired simple-cycle/combined-cycle turbine generator (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate each, ID No. GT-8), is exempted from the requirements of Compliance Assurance Monitoring (CAM) in accordance with 40 CFR Part 64, §64.2(b) (vi). This regulation states that if a Part 70 permit specifies a continuous compliance determination method (CCDM) as defined in 40 CFR §64.1, the source is exempt from CAM.

Note: (CCDM is a method, specified by the applicable standard or an applicable permit condition, which: (1) Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and (2) Provides data either in units of the standard or correlated directly with the compliance limit. Regulatory language will be added to the permit. See Section VII of this review.

6. 15A NCAC 2D .2400 “Clean Air Interstate Rules” (CAIR)

The one natural gas/No. 2 fuel oil-fired simple-cycle/combined-cycle turbine generator (General Electric Model No. 5001P, 341.1 million Btu per hour nominal heat input rate, ID No. GT-8), is subject to CAIR.

On March 15, 2006 the U.S. Environmental Protection Agency (EPA) promulgated federal implementation plans, or FIPs, for power plants to ensure that the emissions reductions required by the Clean Air Interstate Rule (CAIR) are achieved on schedule. The CAIR requires states to reduce emissions of nitrogen oxides (NOx) and sulfur dioxide (SO₂) that significantly contribute to fine particle (PM 2.5) and ground-level ozone pollution problems in downwind states. 28 States and the District of Columbia will be required to revise their state implementation plans. Each state covered by CAIR may independently determine which emission sources to control and which control measures to adopt. CAIR includes model rules for multi-state cap and trade programs for power plants that states may choose to adopt to meet the required emissions reductions in a flexible and highly cost-effective manner. The rule specifies emissions reductions requirements for SO₂ and NOx. The first phase of NOx reductions starts in 2009 (covering 2009-2014) and the first phase of SO₂ reductions starts in 2010 (covering 2010-2014). The second phase of both SO₂ and NOx reductions starts in 2015 (covering 2015 and thereafter).

Regulatory language will be added to the permit. See Section VIII of this review.

VII. Compliance Assurance Monitoring:

This regulation states that if a Part 70 permit specifies a continuous compliance determination method (CCDM) as defined in 40 CFR §64.1, the source is exempt from CAM.

Turbine (GT-8) employs water injection to meet the NSPS, Subpart GG emission limit for NOx and has potential pre-control emissions greater than the major source threshold for NOx (100 tons per year). Water injection meets the definition of *control device* under Part 64. This turbine will be using the requirements under NSPS, Subpart GG to provide a continuous monitoring system in order to demonstrate reasonable assurance of compliance with the NOx limits. Subpart GG requires that the facility establish water-to-fuel curves for a turbine showing compliance with the permitted NOx limits, as developed during a stack test. However, rather than incorporating the water-to-fuel injection curves into CAM to demonstrate reasonable assurance of compliance with the NOx limits, the Title V permit will add testing, monitoring/ recordkeeping, and reporting requirements for compliance with the NOx emission limits for this combustion turbine.

VII. Compliance Assurance Monitoring: - Continued-

These upgraded conditions will allow, and ensure, that the use of water injection to control NOx emissions for the turbines meets the definition of the CAM exemption in §64.2(b)(vi) of 40 CFR Part 64 for “Emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method...” *As a result of the upgraded monitoring, recordkeeping, and reporting and the fact that CCDM meets the CAM exemption, CAM does not apply and will not be added into the permit.*

VIII. Clean Air Interstate Rules” (CAIR):

B. 15A NCAC 2D .2400 “Clean Air Interstate Rule” (CAIR)

- **Five (5) natural gas/No. 2 fuel oil-fired simple-cycle/combined-cycle internal combustion turbines (ID Nos. GT-1, GT-2, GT-3, GT-6, GT-7)**
- **Two (2) natural gas/No. 2 fuel oil-fired simple-cycle internal combustion turbines (ID Nos. GT-4, GT-5) d**
- **One (1) natural gas/No. 2 fuel oil-fired simple-cycle/combined-cycle internal combustion turbine (ID Nos. GT-8)**

1. The annual allocations of sulfur dioxide and nitrogen dioxide allowances shall be determined by the US EPA. The emissions of sulfur dioxide and nitrogen dioxide of a source shall not exceed the number of allowances that it has in its compliance account established and administered in accordance with 15A NCAC 2D .2408.
2. Emission measurement requirements:
 - a. Emission measurements recorded and reported according to 40 CFR Part 96 Subpart HH shall be used to determine compliance by each CAIR NO_x source with its limitation according to 40 CFR 96.106(c).
 - a. Emission measurements recorded and reported according to 40 CFR Part 96 Subpart HHH shall be used to determine compliance by each CAIR SO₂ source with its limitation according to 40 CFR 96.206(c).
3. Excess Emissions:
 - a. The provisions of 40 CFR 96.106(d) shall be used for excess NO_x emissions.
 - b. The provisions of 40 CFR 96.206(d) shall be used for excess SO₂ emissions

Monitoring/Reporting/Recordkeeping [15A NCAC 2D .2407]

4. The owner or operator of a CAIR unit shall comply with the monitoring, recordkeeping, and reporting requirements in:
 - a. 40 CFR 96.106(b) and (e) and in 40 CFR Part 96, Subpart HH for each CAIR NO_x unit;
 - b. 40 CFR 96.206(b) and (e) and in 40 CFR Part 96, Subpart HHH for each CAIR SO₂ unit;
 - c. 40 CFR 96.306(b) and (e) and in 40 CFR Part 96, Subpart HHHH for each CAIR Ozone Season NO_x unit.

Trading Program and Banking [15A NCAC 2D .2408]

5. The United States Environmental Protection Agency shall administer the allowance tracking system according to the procedures in:
 - a. 40 CFR Part 96, Subpart FF and Subpart GG for nitrogen oxides;
 - b. 40 CFR Part 96, Subpart FFF and Subpart GGG for sulfur dioxide; and
 - c. 40 CFR Part 96, Subpart FFFF and Subpart GGGG for ozone season nitrogen oxides.
6. The owners and operators of each source covered under this Section shall have a compliance account in the EPA administered tracking system that satisfies the requirements of:
 - a. 40 CFR 96.151 for nitrogen oxides,
 - b. 40 CFR 96.251 for sulfur dioxides, and
 - b. 40 CFR 96.351 for ozone season nitrogen oxides.
7. Any person may apply to open a general account to hold and transfer allowances by using the procedures and meeting the requirements in:
 - a. 40 CFR 96.151(b) for nitrogen oxides and may close that account using the procedures in 40 CFR 96.157,
 - b. 40 CFR 96.251(b) for sulfur dioxides and may close that account using the procedures in 40 CFR 96.257, and
 - c. 40 CFR 96.351(b) for ozone season nitrogen oxides and may close that account using the procedures in 40 CFR 96.357.

8. Allowancetransfers:
 - a. Any person who has a compliance or general account established under 40CFR96.151 may transfer allowances using the procedures in 40 CFR 96.160.
 - b. Any person who has a compliance or general account established under 40CFR96.251 may transfer allowances using the procedures in 40 CFR 96.260.
 - c. Any person who has a compliance or general account established under 40 CFR 96.351 may transfer allowances using the procedures in 40 CFR 96.360.
 9. Persons with accounts shall submit information to EPA following the requirements of:
 - a. 40 CFR 96.152 for nitrogen oxides,
 - b. 40 CFR 96.252 for sulfur dioxides, and
 - c. 40 CFR 96.352 for ozone season nitrogen oxides.
 10. Any person who has a compliance account or a general account may bank allowances for future use or transfer under:
 - a. 40 CFR 96.155 for nitrogen oxides,
 - b. 40 CFR 96.255 for sulfur dioxides, and
 - c. 40 CFR 96.355 for ozone season nitrogen oxides.
 11. The appeal procedures for decisions of the Administrator are set forth in:
 - a. 40 CFR 96.108 for nitrogen oxides,
 - b. 40 CFR 96.208 for sulfur dioxides, and
 - c. 40 CFR 96.308 for ozone season nitrogen oxides.
- IX.** A zoning consistency determination **is not** required for this renewal application or the second part of the 2-step significant process for this application.
- X.** An application fee **is not** required for renewal application (2600094.07A).
- XI.** A professional engineer's seal **is not** required for either of these applications because no new control devices are being added.
- XII.** The appropriate number of copies were received for the renewal application (2600094.07A), received by the DAQ on February 19, 2007.
- XIV.** The application did contain the Reduction and Recycling Form.
- XV.** The application was signed by an authorized official as defined by 15A NCAC 2Q .0304(j).
- XVI.** An air toxics review **is not** required because no new sources are being added in this renewal application nor in the second step of the significant modification.
- XVII. Other:**
This facility is not subject to 40 CFR Part 68, Prevention of Accidental Releases program, Section 112(r) of the Clean Air Act because the facility does not have any substances above the applicable threshold.
- XVIII. Public Notice/EPA Review:**
A thirty-day public notice and a forty-five day EPA review period **is required.**
- Public notice:** The 30 day public notice period was from **January 16, 2008** through **February 15, 2008**.
____public comments were received for this permit application.
- EPA 45-Day review Period:** The DAQ sent copies of the appropriate information to the USEPA on prior to the public notice. The EPA 45-day review period was from **January 16, 2008** through **March 3, 2008**. The USEPA ____ have any comments on the renewal permit for this facility.

IX. Recommendations

This renewal permit for Public Works Commission, which is located at 2274 Custer Avenue, State Road 1723, Fayetteville, Cumberland County, North Carolina, has been reviewed by the DAQ to determine compliance with all procedures and requirements. The DAQ has determined that this facility is complying or will achieve compliance as specified in the permit with all applicable requirements.

The permit and engineering review were sent to the Regional Office and the applicant on December 4, 2007.

Regional Comments for this permit and review were received on December 27, 2007. Comments from the applicant were received on December 11, 2007. All legitimate comments were addressed in the review and the final permit.

This permit does not contain a Part II Section.

Issue permit No. 03029T15.