Division of Air Quality
601 57th Street SE
Charleston, WV 25304
Phone (304) 926-0475 • FAX: (304) 926-0479

Ear Ray Tomblin, Governor
Randy C. Huffman, Cabinet Secretary
www.dep.wv.gov

ENGINEERING EVALUATION / FACT SHEET

BACKGROUND INFORMATION

Application No.:	R14-0013D
Plant ID No.:	031-00002
Applicant:	Columbia Gas Transmission LLC
Facility Name:	Lost River Compressor Station
Location:	Hardy County
NAICS Code:	486210
Application Type:	Minor Modification
Received Date:	November 21, 2012
Engineer Assigned:	Joe Kessler
Fee Amount:	$2,000
Date Received:	November 30, 2012
Complete Date:	April 11, 2013
Due Date:	July 10, 2013
Applicant Ad Date:	December 11, 2012
Newspaper:	*Grant County Press*
UTM's:	Easting: 685.5 km Northing: 4,305.1 km Zone: 17
Latitude/Longitude:	38.87517/-78.86162
Description:	Addition of two (2) new Solar Taurus 70 Combustion Turbines and removal of three (3) existing Clark HRA-8T Compressor Engines. A Prevention of Significant Deterioration (PSD) applicability analysis is included in the following review.

On February 19, 2003, Columbia Gas Transmission LLC (Columbia Gas) was issued PSD Permit Number R14-0013 for a major modification of the Lost River Compressor Station (which was constructed in 1952). The major modification consisted of removing limitations on Engine E10 (Clark TLAD-10 4,640 hp) that had not been previously permitted but had been operating with restrictions under a under a Consent Order (signed in 1990) with the West Virginia Air Pollution Control Commission. The following is a brief discussion of substantive preconstruction permitting actions involving the facility since that time.

- On July 10, 2006, Permit Number R14-0013A was issued to Columbia Gas as a minor modification to a major source. The modification involved adjusting CO emission levels from engines E1 through E9.

- On August 8, 2007, Permit Number R14-0013B was issued to Columbia Gas as a minor modification to a major source. The modification involved the addition of Engine E11 and the removal of Engines E03 and E06 (which did not occur until 2009).

- On April 17, 2008, Permit Number R14-0013C was issued to Columbia Gas as a minor modification to a major source. The modification involved changing the required retirement date of Engines E03 and E06.

DESCRIPTION OF PROCESS/MODIFICATIONS

Existing Facility

The existing Lost River Compressor Station is a typical large natural gas compression facility that utilizes reciprocating internal combustion engines (RICE) to drive centrifugal gas compressors. In addition to compressor engines the existing facility also contains two (2) natural gas-fired emergency generators, one (1) waste water evaporator/boiler, one (1) fuel gas heater, and numerous storage tanks. The existing facility consists of the following substantive combustion sources:

Table 1: Lost River Combustion Sources

Emission Unit ID	Description	Make/Model	Design Capacity	Installed
001-01	Heating System Boiler	Pennco 633SA	3.99 MMBtu/hr	1953
001-02	Fuel Heater #1	NATCO SBW/20-8D	0.72 MMBtu/hr	1990
001-03	Wastewater Evaporator Boiler	SAMSCO	0.20 MMBtu/hr	1997
002-01	Compressor Engine	Clark HRA-8T	1,320 hp	1953
002-02	Compressor Engine	Clark HRA-8T	1,320 hp	1953
002-04	Compressor Engine	Clark HRA-8T	1,320 hp	1953
002-05	Compressor Engine	Clark HRA-8T	1,320 hp	1954
002-07	Compressor Engine	Clark TLA-8	2,700 hp	1969
002-08	Compressor Engine	Clark TLA-8	2,700 hp	1969
002-09	Compressor Engine	Clark TLA-8	2,700 hp	1970
002-10	Compressor Engine	Clark TLA-10	4,640 hp	1991
002-11	Emergency Generator	Ingersoll-RandPVG-6	306 hp	1952
002-12	Emergency Generator	Waukesha VGF48GL	1,063 hp	2009
002-13	Compressor Engine	Caterpillar G3616 4	4,735 hp	2009

Proposed Modifications

The proposed modifications evaluated herein are:

- Addition of two (2) Solar Taurus 70 9,236 hp natural gas-fired turbines (003-01 and 003-02);

- Addition of one (1) 0.75 mmBtu/hr and one (1) 0.25 mmBtu/hr natural gas-fired Fuel Heater (001--04 and 001-05);

- Addition of forty (40) 0.072 mmBtu/hr natural gas-fired Catalytic Heaters (001-06);

- Permanent removal from service of three (3) Clark HRA-8T 1,320 hp compressor engines (002-02, 002-04, and 002-05) from service; and

- Placement of three (3) Clark TLA-8 2,700 hp compressor engines (E07 - E09) and one (1) Clark TLA-10 4,640 hp compressor engine (E10) on standby status;

In addition to the above, Columbia Gas is requesting the addition to the permit of an Emergency Generator (002-12) installed in 2009 but not previously permitted. It is important to note that while four additional engines are to be put in "stand-by" mode, Columbia Gas is not requesting any limitations on the engines' PTE.

SITE INSPECTION

On April 4, 2012 Mr. Karl Dettinger of the Compliance/Enforcement (C/E) Section conducted a site inspection of the Lost River Compressor Station. The result of the inspection was, at the time: "Status 30 - In Compliance." However, in October 2012, Columbia Gas was issued a Notice of Violation (NOV) for failure to conduct required 40 CFR 63, Subpart ZZZZ performance testing on Engine 002-013. Subsequently, this testing was conducted on November 6, 2012 and it demonstrated that the engine was in compliance with Subpart ZZZZ. Due to the recent site inspection of the facility conducted by a C/E inspector, and the nature of the modifications, an additional inspection by the writer was deemed unnecessary.

AIR EMISSIONS AND CALCULATION METHODOLOGIES

The following will detail the air emissions and calculation methodologies for the emission units added/removed as part of this permitting action and added/removed during the PSD applicability analysis contemporaneous period (see below under the Regulatory Applicability for a full discussion of this analysis).

New Emission Units

Solar Taurus 70 Turbines

Potential emissions from each of the two (2) 9,236 hp natural gas-fired Solar Taurus 70 turbines (003-01 and 003-02) were based on emission factors provided by the turbine manufacturer (NO_x, CO, and VOC), fuel mass balance calculations (SO_2), and as given in AP-42, Section 3.1 (particulate matter and GHGs). AP-42 is a database of emission factors maintained by USEPA.

For particulate matter, hourly emissions were based on the maximum design heat input (MDHI) of the engine of 83.89 mmBtu/hr and annual emissions were based on 8,760 hours of operation per year. For GHGs, hourly emissions were based on the MDHI of the engine and annual emissions were based on an aggregate (of both turbines) annual heat input rate of 1,280,000 mmBtu/yr (a capacity factor of 87.09%). For SO_2, hourly emissions were based on a maximum natural gas usage of 82,245 ft^3/hour and a worst-case fuel (short-term) sulfur level of 20 grains/100 ft^3-natural gas. Annual emissions of SO_2 were based on a worst-case fuel (long-term) sulfur level of 0.25 grains/100 ft^3-natural gas and 8,760 hours of operation per year. For NO_x, CO, and VOC, hourly emissions were based on the emission factors provided by Solar that are temperature/load dependent. Annual emissions were based on an aggregate total operation of 8,760 hours of operation per year with a worst-case estimate of operational hours at each temperature/load with different emissions characteristics. The following table details the potential-to-emit (PTE) of each engine:

Table 1: Per- Turbine PTE

Pollutant	Emission Factor	Source	Hourly[(1)] (lb/hr)	Annual (ton/yr)
CO	Varies Based on Load/Temperature -See Above	Vendor	1,708.23	51.50
NO_X	Varies Based on Load/Temperature -See Above	Vendor	42.84	23.79
PM[(2)]	6.60×10^{-3} lb/mmBtu	AP-42, Table 3.1-2a	0.55	2.43
SO_2	20 grains-S/ft^3/hr 0.25 grains-S/ft^3/yr	Mass Balance	4.70	0.26
VOCs[(3)]	Varies Based on Load/Temperature	Vendor	24.40	3.68
Formaldehyde	*7.10×10^{-4} lb/mmBtu*	*AP-42, Table 3.1-3*	*0.06*	*0.26*
Non-CH_2O HAPs[(4)]	*3.17×10^{-4} lb/mmBtu*	*AP-42, Table 3.1-3*	*0.03*	*0.12*
Total HAPs	n/a	n/a	0.09	0.38
CH_4	*8.60×10^{-3} lb/mmBtu*	*AP-42, Table 3.1-2a*	*0.72*	*2.75*
N_2O	*3.00×10^{-3} lb/mmBtu*	*AP-42, Table 3.1-2a*	*0.25*	*0.96*
CO_2	*110 lb/mmBtu*	*AP-42, Table 3.1-2a*	*9,227.90*	*35,199.82*
CO_2e[(5)]	n/a	n/a	n/a	35,257.62

(1) Hourly emissions listed are for the worst-case short-term emissions even if expected to occur only rarely.
(2) Conservatively, all particulate matter emissions are assumed to be less than 2.5 microns. Includes condensables.
(3) VOC emissions based on 25% of Unburnt Hydrocarbon (UHC) vendor emission factors per Solar.
(4) An aggregate of all HAP emission factors (minus C_2HO) from AP-42 Table 3.1-3.
(5) Based on multiplying the mass amount of emissions for each of the six greenhouse gases by the gas's associated global warming potential published at Table A-1 to Subpart A of 40 CFR Part 98 - Global Warming Potentials. Used to determine major source status of facilities under 45CSR14.

Natural Gas-Fired Heaters

Potential emissions from the Fuel Heaters (001-04 and 001-05) and the Catalytic Heaters (001-06) were based on the emission factors provided for natural gas combustion as given in AP-42 Section 1.4. and fuel mass balance calculations (SO_2). Hourly emissions were based on the maximum design heat input (MDHI) of each unit and annual emissions were based on an annual operation of 8,760 hours. A heat content of the gas of 1,020 Btu/scf was used in the calculations. For SO_2, hourly emissions were based on a maximum natural gas usage of 82,245 ft^3/hour and a worst-case fuel (short-term) sulfur level of 20 grains/100 ft^3-natural gas. Annual emissions of SO_2 were based on a worst-case fuel (long-term) sulfur level of 0.25 grains/100 ft^3-natural gas and 8,760 hours of operation per year.

Table 2: Natural Gas-Fired Heaters' Exhaust PTE

Pollutant	**Fuel Heater 2**		**Fuel Heater 3**		**Catalytic Heaters**	
	lbs/hr	**tons/year**	**lbs/hr**	**tons/year**	**lbs/hr**	**tons/year**
CO	0.06	0.27	0.02	0.09	0.24	1.04
NO_X	0.07	0.32	0.02	0.11	0.28	1.24
PM(1)	0.01	0.02	~0.00	0.01	0.02	0.09
SO_2	0.04	~0.00	0.01	~0.00	0.16	0.01
VOCs	0.00	0.02	~0.00	<0.01	0.02	0.07
HAPs(2)	~0.00	0.01	~0.00	~0.00	0.01	0.02
CO_2e(3)	82.50	361.35	27.50	120.45	316.80	1,387.58

(1) Conservatively, all particulate matter emissions are assumed to be less than 2.5 microns. Includes condensables.
(2) As based on the emission rate of Hexane in AP-42, Section 1.4.
(3) Due to the small size of the units in question, the emissions of methane were not included.

Removed Emission Units

Clark HRA-8T Engines (002-02, 002-03, 002-04, 002-05, and 002-06)

Potential emissions from the three (3) 2-Stroke Lean Burn (2SLB) Clark HRA-8T 1,320 hp engines (002-02, 002-04, and 002-05) to be removed were based on the annual emission limits () given under Section A of R14-0013C (NO_x and CO) and on AP-42, Section 3.2 (other criteria pollutants, HAPs, and GHGs). When AP-42 emission factors were used, hourly emissions were based on the maximum design heat input (MDHI) of each unit (calculated @ 8,200 Btu/hp) and annual emissions were based on an annual operation of 8,760 hours.

Actual emissions of NO_x and CO from the above units and the two (2) 2SLB Clark HRA-8T 1,320 hp engines (002-03 and 002-06) removed in 2009 are also based on the emission factors discussed above with actual operating data from June 2007 through May 2009 used to calculate annualized average emissions. For the determination of actual emissions, however, Columbia did not use the hourly emission limits (given in g/hp-hr) listed in R13-0013C for the engines as these represent short-term emission limits with built-in safety factors. Instead the annual emission limits were used and, based on 8,760 hours of operation per year, a long-term average hourly emission rate was calculated. This hourly emission rate, when combined with the operating data, was used to calculate actual emissions. Using the long-term average hourly emission rate produces lower emissions than using the short-term emission limit listed in the permit (see 45CSR14 discussion in the Regulatory Applicability section below).

Other Contemporaneous Changes

Caterpillar G36164 Engine (002-13)

Potential emissions from the 4-Stroke Lean Burn (4SLB) Caterpillar G36164 4,735 hp engine (002-13) added in 2009 were based on information provided by the vendor (NO_x, CO, VOC, and formaldehyde) and on AP-42, Section 3.2 (other pollutants). When AP-42 emission factors were used, hourly emissions were based on the MDHI of the unit (31.90 mmBtu/hr calculated @ 6,738 Btu/hp) and annual emissions were based on an annual operation of 8,760 hours.

Waukesha Model VGF48GL (002-12)

Although added in 2009, the 4SLB Waukesha Model VGF48GL 1,063 hp emergency generator (002-0012) has not been previously permitted. Potential emissions from this unit are based on information provided by the vendor (NO_x, CO, VOC) and on AP-42, Section 3.2 (other pollutants). When AP-42 emission factors were used, hourly emissions were based on the MDHI of the unit (7.25 mmBtu/hr calculated @ 6,825 Btu/hp) and annual emissions were based on an annual operation of 500 hours. Although not limited to 500 hours in a previous permit (it will be limited to 500 hours of annual operation in the draft permit), based on a September 6, 1995 USEPA memo from John Seitz, it is appropriate to calculate the PTE of an emergency generator at 500 hours/yr: "The EPA believes that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions."

Project Emissions Summary

Based on the above estimation methodology, which is determined to be appropriate, a summary of the post-modification PTE change is given in the following table:

Table 3: Annual (ton/yr) Criteria Pollutant/HAP/GHG PTE Summary

Source	CO	NO_x	PM[1]	SO_2	VOCs	HAPs	CO_2e
Turbine 003-01	51.50	23.79	2.43	0.26	3.68	0.38	35,258
Turbine 003-02	51.50	23.79	2.43	0.26	3.68	0.38	35,258
Fuel Heater 001-04	0.27	0.32	0.02	~0.00	0.02	0.01	361
Fuel Heater 001-05	0.09	0.11	0.01	~0.00	<0.01	~0.00	120
Catalytic Heaters 001-06	1.04	1.24	0.09	0.01	0.07	0.02	1,388
New Equipment Increase →	***104.40***	***49.25***	***4.98***	***0.53***	***7.46***	***0.79***	***72,385***
Engine 002-02	(28.10)	(103.20)	(1.70)	(0.04)	(5.50)	(3.17)	(6,659)
Engine 002-04	(28.10)	(103.20)	(1.70)	(0.04)	(5.50)	(3.17)	(6,659)
Engine 002-05	(28.10)	(103.20)	(1.70)	(0.04)	(5.50)	(3.17)	(6,659)

Removed Equipment Decrease ➜	***(84.30)***	***(309.60)***	***(5.10)***	***(0.12)***	***(16.50)***	***(9.51)***	***(19,977)***
Project PTE Change ➜	***20.10***	***(260.35)***	***(0.12)***	***0.41***	***(9.04)***	***(8.72)***	***52,408***

(1) Conservatively, all particulate matter emissions are assumed to be less than 2.5 microns. Includes condensables.

Based on information given in the Title V Permit Renewal Fact Sheet (R30-03100002-2012), the new post-modification facility-wide PTE is given in the following table:

Table 4: Post-Modification Change in Annual (ton/yr) PTE

Source	NO_x	CO	VOCs	SO_2	PM(1)	HAPs	CO_2e(2)
Pre-Modification(1)	1,203.62	356.90	119.14	0.68	24.04	51.21	>100,000
Modification Change	(260.35)	20.10	(9.04)	0.41	(0.12)	(8.72)	52,408
Post-Modification	***943.27***	***377.00***	***110.10***	***1.09***	***23.92***	***42.49***	***>100,000***

(1) As listed in Title V Permit Renewal Fact Sheet (R30-03100002-2012) issued in 2012.
(2) CO_2e was not reported in the Title V Renewal Permit Fact Sheet. Assumed that pre-modification and post-modification rate is in excess of 100,000 TPY.

REGULATORY APPLICABILITY

This section will address the potential regulatory applicability/non-applicability of substantive state and federal air quality rules relevant to the new emissions units discussed above.

45CSR2: To Prevent and Control Particulate Air Pollution from Combustion of Fuel in Indirect Heat Exchangers

The Fuel Heaters (001-04 and 001-05) and the Catalytic Heaters (001-06) each have been determined to meet the definition of a "fuel burning unit" under 45CSR2 and are, therefore, subject to the applicable requirements therein. However, pursuant to the exemption given under §45-2-11, as the MDHI of the units are each less than 10 mmBtu/hr, they are not subject to sections 4, 5, 6, 8 and 9 of 45CSR2. The only remaining substantive requirement is under Section 3.1 - Visible Emissions Standards.

Pursuant to 45CSR2, Section 3.1, the heaters are subject to an opacity limit of 10%. Proper maintenance and operation of the units (and the use of natural gas as fuel) should keep the opacity of the units well below 10% during normal operations.

45CSR10: To Prevent and Control Air Pollution from the Emission of Sulfur Oxides (non-applicability)

45CSR10 has requirements limiting SO_2 emissions from "fuel burning units," limiting in-stack SO_2 concentrations of "manufacturing processes," and limiting H_2S concentrations in process gas streams. The only potential applicability of 45CSR10 to Lost River is the limitations on fuel burning units. The Fuel Heaters (001-04 and 001-05) and the Catalytic Heaters (001-06) have each been determined to meet the definition of a "fuel burning unit" under 45CSR10. However, pursuant to the exemption given under §45-10-10.1, as the MDHI of the units are all less than 10 mmBtu/hr, those units are not subject to the limitations on fuel burning units under 45CSR10.

45CSR13: Permits for Construction, Modification, Relocation and Operation of Stationary Sources of Air Pollutants, Notification Requirements, Administrative Updates, Temporary Permits, General Permits, and Procedures for Evaluation

The proposed changes at Lost River have the potential to increase a regulated pollutant in excess of six (6) lbs/hour and ten (10) TPY that would, pursuant to §45-13-2.17, define the changes as a "modification" under 45CSR13. Pursuant to §45-13-5.1, "[n]o person shall cause, suffer, allow or permit the modification . . . and operation of any stationary source to be commenced without . . . obtaining a permit to construct." Therefore, Columbia Gas was required to obtain a permit under 45CSR13 for the proposed modification discussed herein.

As required under §45-13-8.3 ("Notice Level A"), Columbia Gas placed a Class I legal advertisement in a "newspaper of general circulation in the area where the source is . . . located." The ad ran on December 11, 2012 in the *Grant County Press*. The affidavit of publication for this legal advertisement was submitted on January 11, 2013.

45CSR14: Permits for Construction and Major Modification of Major Stationary Sources of Air Pollution for the Prevention of Significant Deterioration

Determination of Existing Major Source Status

Columbia Gas' Lost River Compressor Station is located in an area - Hardy County - classified as "in attainment" with all National Ambient Air Quality Standards (NAAQS) and, therefore, the major source status of the source is determined under 45CSR14. As the facility is not a source listed under §45-14-2.43(a), the threshold for defining the existing source as a "major stationary source," pursuant to §45-14-2.43(b), is a potential-to-emit (PTE) of 250 TPY of any regulated pollutant (or greater than 100,000 TPY of CO_2e pursuant to §45-14-2.80(e)(2)).

As shown above in Table 4, the existing unmodified source has a PTE of NO_x and CO greater than 250 TPY (and a CO_2e PTE of greater than 100,000 TPY). The PTE of these pollutants define the source as an existing major stationary source under 45CSR14.

Determination of a Major Modification

As Columbia Gas is proposing a "physical change in or change in the method of operation of a major stationary source," included in the permit application is an applicability analysis to determine if the proposed changes to the facility are defined as a "major modification" and subject to Prevention of Significant Deterioration (PSD) review under 45CSR14. A "major modification" is defined under section 2.40 of 45CSR14 as a:

> . . . physical change in or change in the method of operation of a major stationary source which results in: a significant emissions increase (as defined in subsection 2.75) of any regulated NSR pollutant (as

defined in subsection 2.66); and a significant net emissions increase of that pollutant from the major stationary source. [. . .]

Section 3.4 of 45CSR14 provides guidance on the process of determining if proposed changes are a major modification. §45-14-3.4(a) states that:

> . . . consistent with the definition of major modification contained in subsection 2.40, a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases -- a significant emissions increase (as defined in subsection 2.75), and a significant net emissions increase (as defined in subsections 2.46 and 2.74). The proposed project is not a major modification if it does not cause a significant emissions increase. [. . .]

Therefore, for the proposed changes to meet the definition of a major modification, the changes themselves must result in a significant emissions increase. The methodology for calculating the emissions increase under the first step is given under Sections 3.4(b), 3.4(c), 3.4(d) and 3.4(f). The substantive language of each is given below:

> [§45-14-3.4(b)]
> The procedure for calculating (before beginning actual construction) whether a significant emissions increase (i.e., the first step of the process) will occur depends upon the type of emissions units being modified, according to subdivisions 3.4.c through 3.4.f.

> [§45-14-3.4(c)]
> Actual-to-projected-actual applicability test for projects that only involve existing emissions units. -- A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions (as defined in subsection 2.63) and the baseline actual emissions (as defined in subdivisions 2.8.a and 2.8.b), for each existing emissions unit, equals or exceeds the significant amount for that pollutant (as defined in subsection 2.74).

> [§45-14-3.4(d)]
> Actual-to-potential test for projects that only involve construction of a new emissions unit(s). – A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit (as defined in subsection 2.58) from each new emissions unit following completion of the project and the baseline actual emissions (as defined in subdivision 2.8.c) of these units before the project equals or exceeds the significant amount for that pollutant (as defined in subsection 2.74).

> [§45-14-3.4(f)]
> Hybrid test for projects that involve multiple types of emissions units. -- A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the emissions increases for each emissions unit, using the method specified in subdivisions 3.4.c through 3.4.d as applicable with respect to each emissions unit, for each type of emissions unit equals or exceeds the significant amount for that pollutant (as defined in subsection 2.74).

Further, under the definition of "projected actual emissions" - Section 2.63(a)(4), the applicant may use an emission unit's PTE in lieu of projecting actual emissions.

Columbia Gas PSD Applicability Analysis

Based on the above, Columbia Gas included a PSD applicability analysis for the proposed project as outlined in the Description of Process/Modifications above. Pursuant to Step 1 of the of the applicability analysis, the following table details the annual emissions increase of the proposed new equipment:

Table 5: PSD Applicability Analysis Step 1 - Project Increase[1]

Source	CO	NO_x	PM[2]	SO_2	VOCs	CO_2e
Turbine 003-01	51.50	23.79	2.43	0.26	3.68	35,258
Turbine 003-02	51.50	23.79	2.43	0.26	3.68	35,258
Fuel Heater 001-04	0.27	0.32	0.02	~0.00	0.02	361
Fuel Heater 001-05	0.09	0.11	0.01	~0.00	<0.01	120
Catalytic Heaters 001-06	1.04	1.24	0.09	0.01	0.07	1,388
New Equipment Increase ➜	**104.40**	**49.25**	**4.98**	**0.53**	**7.46**	**72,385**
PSD Significance Level	*100*	*40*	*10*	*40*	*40*	*75,000*
Potential Major Modification?	*Yes*	*Yes*	*No*	*No*	*No*	*No*

(1) In lieu of projecting actual emissions, emission unit's PTEs were used.
(2) Conservatively, all particulate matter emissions are assumed to be less than 2.5 microns. Includes condensables.

Based on the above, only CO and NO_x have the potential to trigger a major modification under 45CSR14 (equal a "significant emissions increase"). Therefore, the other pollutants are no longer of concern. While Columbia Gas has claimed decreases as part of the project (removal of three compressor engines), these decreases may only be included in the analysis as part of Step 2 - the determination of a "significant net emissions increase." This is given in the following table:

Table 6: PSD Applicability Analysis Step 2 - Project Net Emissions Increase

Source	CO	NO_x
New Equipment Increase ➜	**104.40**	**49.25**
Proposed Project Removed Equipment		
Engine 002-02	(6.33)	(23.30)
Engine 002-04	(6.87)	(25.29)
Engine 002-05	(7.07)	(26.04)
Removed Equipment Decrease ➜	***(20.27)***	***(74.63)***
Project Change ➜	***84.13***	***(25.38)***

For the removed sources, "baseline actual emissions" were based - pursuant to the definition under §45-14-2.8 - on the annualized actual operating data from the calendar years June 2007 through May 2009 and the emission factors as described above in the AIR EMISSIONS AND CALCULATION METHODOLOGIES Section.

It is important to note that when any emissions decrease is claimed including those associated with the proposed modification, all source-wide creditable and contemporaneous increases and decreases of the pollutant subject to netting must be included in the PSD applicability analysis (see DRAFT New Sour Review Workshop Manual - i.e., "The Puzzle Book" pp. A.36). This determination is defined under the definition of "net emissions increase" [§45-14-2.46] and must include “any other increases and decreases in actual emissions at the major source that are contemporaneous with the particular change and are otherwise creditable.” A change is contemporaneous if it “occurs not more than five (5) years prior to the date on which construction on the particular change commences nor later than the date on which the increase from the particular change occurs.” Based on the expected date of construction of the new equipment - June 2013, the contemporaneous period extends back to June 2008. Several changes have occurred since that time and are detailed in the following table:

Table 7: PSD Applicability Analysis Step 2 Continued - Contemporaneous Changes

Source	CO	NO_x
Project Change ➜	**84.13**	**(25.38)**
Contemporaneous Decreases		
Engine 002-03 (June 2009)	(6.98)	(25.70)
Engine 002-06 (June 2009)	(7.01)	(25.80)
Removed Equipment Decrease ➜	***(13.99)***	***(51.50)***
Contemporaneous Increases(1)		
Engine 002-13 (June 2009)	28.55	31.98
Generator 002-12 (2009)	0.76	1.17
Added Equipment Increase ➜	***29.31***	***33.15***
Net Emissions Increase ➜	***99.45***	***(43.73)***

(1) In lieu of projecting actual emissions, emission unit's PTEs were used.

For the removed sources, “baseline actual emissions” were based - pursuant to the definition under §45-14-2.8 - on the annualized actual operating data from the calendar years June 2007 through May 2009 and the emission factors as described above in the AIR EMISSIONS AND CALCULATION METHODOLOGIES Section. Columbia Gas has provided semiannual reports from June 2007 through May 2009 verifying operating data for that time period.

As the net emissions increase of CO and NO_x, when considering creditable contemporaneous increases and decreases, are less than the significant levels, the proposed modifications are not defined as a “major modification” and are not subject to PSD review. The following table provides the complete CO and NO_x PSD Applicability Analysis:

Table 8: CO and NO_x Complete PSD Applicability Analysis

Source	CO	NO_x	
Turbine 003-01	51.50	23.79	***Step 1***
Turbine 003-02	51.50	23.79	
Fuel Heater 001-04	0.27	0.32	

Fuel Heater 001-05	0.09	0.11	
Catalytic Heaters 001-06	1.04	1.24	
Engine 002-02[1]	(6.33)	(23.30)	***Step 2***
Engine 002-04[1]	(6.87)	(25.29)	
Engine 002-05[1]	(7.07)	(26.04)	
Engine 002-03 (June 2009)[1]	(6.98)	(25.70)	***Contemporaneous***
Engine 002-06 (June 2009)[1]	(7.01)	(25.80)	
Engine 002-13 (June 2009)	28.55	31.98	
Generator 002-12 (2009)	0.76	1.17	
Net Emissions Increase ➜	***99.45***	***(43.73)***	
PSD Significance Level	*100*	*40*	
Defined as Major Modification?	***No***	***No***	

(1) Based on actual emissions.

It is important to note that, based on the language of §45-14-2.46(h), and the historical interpretation thereof, the removal of engines 002-02, 002-04, and 002-05 is required by the conclusion of a "reasonable shakedown period" - not to exceed 180 days from startup - of the new turbines (see 4.1.2. and 4.1.3. of the draft permit).

45CSR30: Requirements for Operating Permits

45CSR30 provides for the establishment of a comprehensive air quality permitting system consistent with the requirements of Title V of the Clean Air Act. The Lost River Compressor Station, defined under Title V as a "major source," was last issued a Title V permit on October 31, 2012. Proposed changes evaluated herein must also be incorporated into the facility's Title V operating permit. Commencement of the operations authorized by this permit shall be determined by the appropriate timing limitations associated with Title V permit revisions per 45CSR30.

40 CFR 60 Subpart JJJJ: Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

According to information provided by the applicant, the Waukesha Model VGF48GL1,063 hp emergency generator was manufactured in August 2008. The Subpart JJJJ applicability date for emergency generators is January 1, 2009 and, therefore, the Waukesha is not subject to Subpart JJJJ.

40 CFR 60 Subpart KKKK: Standards of Performance for Stationary Combustion Turbines

Pursuant to §60.4305, Subpart KKKK applies to each "stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005." Columbia Gas' proposed two (2) 9,236 hp natural gas-fired Solar Taurus 70 turbines (003-01 and 003-02) are defined as stationary combustion turbines with a heat input greater than 10 mmBtu/hr (83.89 mmBtu/hr). Therefore, these units are subject to applicable requirements under Subpart KKKK.

Subpart KKKK requires applicable combustion turbines to meet emission limits for NO_x and SO_2. Under §60.4320, the turbines must meet the NO_x emission limits given in Table 1 of Subpart KKKK. As the Solar Turbines are each a "new turbine firing natural gas" between 50 and 850 mmBtu/hr, Table 1 sets a NO_x limit of 25 ppm at 15% O_2 or 150 ng/J of useful output. Based on information provided by Solar, the turbines will have NO_x emission rates of 15 ppm at 15% O_2 at loads above 50% and under normal meteorological conditions. To demonstrate compliance with the limit, §60.4400(a) requires both an initial (within 180 days of startup or 60 days of achieving full load operation) and annual (not to exceed 14 months from previous test) performance test. However, §60.4340 allows the permittee to be exempted from the annual testing if continuous emission monitors or continuous parameter monitoring systems are installed that meet the requirements of the section. Additionally, if the NO_x testing results show emissions less than 75% of the limit, testing frequency can be reduced to once every 2 years (with no more than 26 months after the previous test.)

Subpart KKKK also limits SO_2 emissions from the turbines. Pursuant to §60.4330(a)(2), the facility can meet the SO_2 limit by burning fuel with a total potential SO_2 emissions of less than 0.06 lb/mmBtu. The worst-case hourly emission rate of SO_2 from each turbine is 0.056 lb/mmBtu which is in compliance with Subpart KKKK. Additionally, §60.4365(a) exempts the permittee from monitoring fuel sulfur content if a source burns only natural gas that is covered by a purchase or transportation contract that limits sulfur to no more than 20 grains per 100 scf. Columbia qualifies for this exemption.

TOXICITY ANALYSIS OF NON-CRITERIA REGULATED POLLUTANTS

This section provides an analysis for those regulated pollutants that may be emitted from the new/modified equipment and that are not classified as "criteria pollutants" or Greenhouse Gases. Criteria pollutants are defined as Carbon Monoxide (CO), Lead (Pb), Oxides of Nitrogen (NO_x), Ozone, Particulate Matter (PM), Particulate Matter less than 10 microns (PM_{10}), Particulate Matter less than 2.5 microns ($PM_{2.5}$), and Sulfur Dioxide (SO_2). Criteria pollutants have National Ambient Air Quality Standards (NAAQS) set for each that are designed to protect the public health and welfare. Other pollutants of concern, although designated as non-criteria and without national concentration standards, are regulated through various federal and programs designed to limit their emissions and public exposure. These programs include federal source-specific Hazardous Air Pollutants (HAPs) limits promulgated under 40 CFR 61 (NESHAPS) and 40 CFR 63 (MACT). Any potential applicability to these programs were discussed above under REGULATORY APPLICABILITY.

The majority of non-criteria regulated pollutants fall under the definition of HAPs which, with some revision since, were 188 compounds identified under Section 112(b) of the Clean Air Act (CAA) as pollutants or groups of pollutants that EPA knows or suspects may cause cancer or other serious human health effects. As the net PTE change of HAPs from the modifications discussed herein is a decrease, no toxicity analysis is required.

AIR QUALITY IMPACT ANALYSIS

The estimated maximum emissions of the proposed changes are less than applicability thresholds that would define the proposed changes as a “major modification” under 45CSR14 and, therefore, no air quality impacts modeling analysis was required. Additionally, based on the nature of the proposed modifications, modeling was not required under 45CSR13, Section 7.

MONITORING, COMPLIANCE DEMONSTRATIONS, REPORTING, AND RECORDING OF OPERATIONS

The following substantive monitoring, compliance demonstration, reporting and recording requirements (MRR) shall be required for the new equipment (the MRR requirements for the existing equipment will substantively remain the same as under R14-0013C):

- Columbia Gas shall be required to calculate and record, on a monthly and rolling twelve month basis, the emissions of each pollutant limited under Table 4.1.7(b) of the draft permit generated by turbines 003-01 and 003-02. The calculation shall be based on the emission factors used in permit application R14-0013D and the following information:

  - Columbia Gas shall be required to monitor and record the number of hours that the turbines 003-01 and 003-02 operate in the following operational modes:

    (1) Normal: ≥50% Load and ≥ 10°F;
    (2) Low Temp: < 10°F ≥ -20°F;
    (3) Very Low Temp: < -20°F; and
    (4) Low-Load: < 50% Load.

  - Columbia Gas shall be required to monitor and record the number of startup/shutdowns of each turbine;

  - Columbia Gas shall be required to monitor and record the actual heat input to the turbines.

- For the purposes of demonstrating compliance with visible emissions limitations set forth in 4.1.8(e)of the draft permit, Columbia Gas shall be required to:

  - Conduct an initial Method 22 visual emission observation on the line heaters to determine the compliance with the visible emission provisions. Columbia Gas shall be required to take a minimum of two (2) hours of visual emissions observations on the Fuel Heaters and the Catalytic Heaters;

  - Conduct monthly Method 22 visible emission observations of the Fuel Heaters' and the Catalytic Heaters' stack to ensure proper operation for a minimum of ten (10) minutes each month the Fuel Heaters and the Catalytic Heaters are in operation;

  - In the event visible emissions are observed in excess of the limitations given under 4.1.8(e), Columbia Gas shall be required to take immediate corrective action;

- Columbia Gas shall be required to maintain records of all visual emission observations pursuant to the monitoring required under 4.2.5. of the draft permit including any corrective action taken; and

- Any deviation(s) from the allowable visible emission requirement for any emission source discovered during observations using 40CFR Part 60, Appendix A, Method 9 or 22 shall be reported in writing to the Director of the Division of Air Quality as soon as practicable, but in any case within ten (10) calendar days of the occurrence and shall include at least the following information: the results of the visible determination of opacity of emissions, the cause or suspected cause of the violation(s), and any corrective measures taken or planned.

- For the purposes of demonstrating compliance with the maximum usage limits set forth in 4.1.9(b) of the draft permit, Columbia Gas shall be required to monitor and record the monthly and rolling twelve month hours of operation of the emergency generator.

- Columbia Gas shall be required to meet all applicable Monitoring, Compliance Demonstration, Source-Specific Recording and Reporting Requirements as given under 40 CFR 60, Subpart KKKK and 40 CFR 63, Subpart ZZZZ.

PERFORMANCE TESTING OF OPERATIONS

The following performance testing requirements shall be required for the new equipment:

- In addition to the NO_x performance testing as required under 40 CFR 60, Subpart KKKK, within 60 days after achieving full load, but not later than 180 days after initial startup, and at such times thereafter as may be required by the Director, Columbia Gas shall be required to conduct, or have conducted, a performance test on each turbine to determine compliance with the "normal load" CO emission limit specified under Table 4.1.7(b) of the draft permit and in accordance with 3.3.1. of the draft permit. Columbia Gas shall be required to use an appropriate EPA-approved test method as given under 40 CFR 60, Appendix A and approved in writing by the Director in a protocol submitted pursuant to 3.3.1(c) of the draft permit. The testing shall take place while the engines are operating at "normal load" as defined under 4.2.3(a) of the draft permit.

- In addition to the NO_x performance testing as required under 40 CFR 60, Subpart KKKK, within 60 days after achieving full load, but not later than 180 days after initial startup, and at such times thereafter as may be required by the Director, Columbia Gas shall be required to conduct, or have conducted, a performance test on each turbine to determine compliance with the particulate matter emission limit (Including condensables) specified under Table 4.1.7(b) and in accordance with 3.3.1. of the draft permit. The permittee shall use an appropriate EPA-approved test method as given under 40 CFR 60, Appendix A and approved in writing by the Director in a protocol submitted pursuant to 3.3.1(c) of the draft permit. The testing shall take place while the engines are operating at 100% of load or, if this is not practicable, the results of the test shall scaled up by an appropriate ration to represent operation at 100%

load.

- Columbia Gas shall be required to meet all applicable testing requirements as given under 40 CFR 60, Subpart KKKK and 40 CFR 63, Subpart ZZZZ.

CHANGES TO PERMIT R14-0013C

The following substantive changes were made to Permit Number R14-0013C:

- The Emissions Units Table 1.0 was revised to reflect the changes evaluated herein;
- Requirement 4.1.1 was added to the permit to restrict equipment authorized by the draft permit to that listed under the Emissions Units Table 1.0;
- Direct references to engines 002-03 and 002-06 were removed from the draft permit;
- New emission limits - pre and post shakedown period of the new turbines - for the four (4) remaining Clark HRA-8T engines were added under 4.1.2 of the draft permit;
- Emission limits and operating restrictions of the new Solar Turbines were added under 4.1.7. of the draft permit;
- Emission limits and operating restrictions of the new Fuel Heaters and Catalytic Heaters were added under 4.1.8. of the draft permit;
- Emission limits and operating restrictions of the Emergency Generator were added under 4.1.9. of the draft permit;
- Monitoring and recording requirements for the turbines, heaters, and emergency generator were added under 4.2.5., 4.2.6., and 4.2.7. of the draft permit;
- Performance testing of the new turbines were added under 4.3.2. and 4.3.3. of the draft permit; and
- Due to the restructuring of the permit, some existing requirements were moved to other places in the permit and, therefore, the requirement numbers changed.

RECOMMENDATION TO DIRECTOR

The information provided in the permit application and subsequent revisions thereto indicates that compliance with all applicable state and federal air quality regulations will be achieved. Therefore, I recommend to the Director the issuance of Permit Number R14-0013D to Columbia Gas Transmission LLC for the above discussed modifications at the Lost River Compressor Station located in Mathias, Hardy County, WV.

Joseph Kessler, PE
Engineer

____
Date